INSTITUTE OF ENERGY FOR SE EUROPE

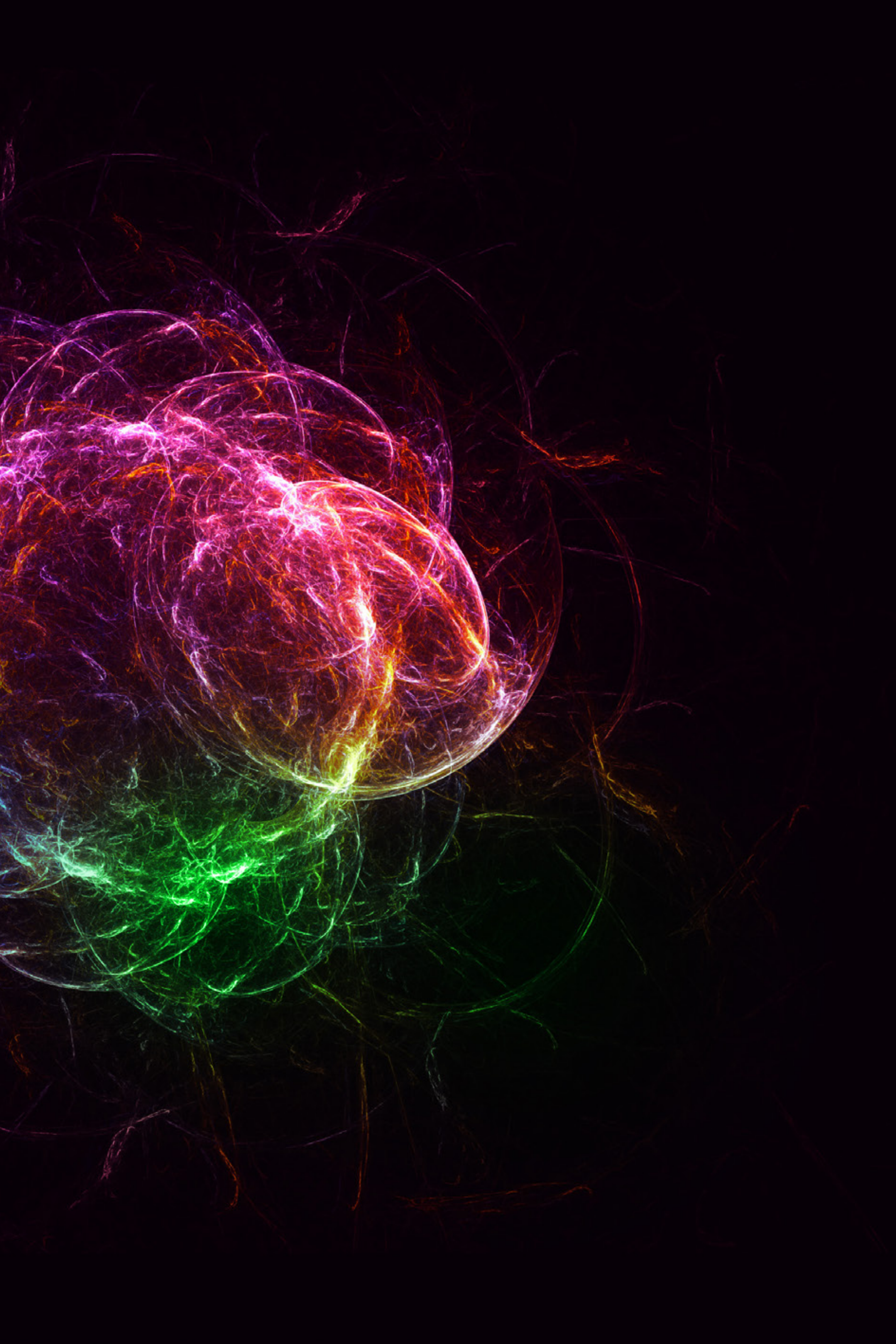
South East Europe Energy Outlook 2021/2022

INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

South East Europe Energy Outlook 2021/2022

INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

Athens, December 2021



INSTITUTE OF ENERGY FOR SE EUROPE

South East Europe Energy Outlook 2021/2022

Lead Sponsor

Sponsors

Supporters


IENE
INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

The Institute of Energy for South East Europe (IENE)

The Institute of Energy for South East Europe (IENE) was founded in 2003 by a small group of independent professionals and business executives active in the energy sector of the region. The Institute, which has its headquarters in Athens, Greece, is a non-governmental and nonprofit organization. The Institute's prime purpose is to constitute a permanent forum where energy issues can be discussed, analyzed, reformulated and presented to a broader audience, in unbiased, objective and credible terms. This is achieved thanks to the Institute's scientific standing, its managerial rectitude and the transparency of all its operations.

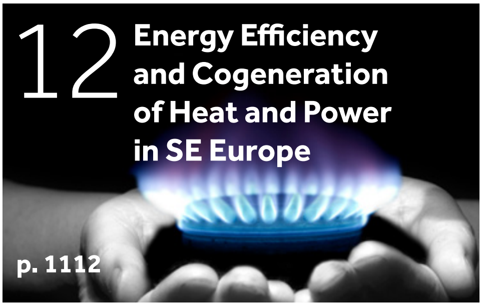
The Institute activities span all forms of energy including hydrocarbons, solid fuels, electricity, emissions, nuclear, renewables, energy efficiency and energy technologies. The Institute is largely funded from its membership which includes both corporate entities and individual energy professionals.

One of IENE's key objectives is to participate in the formulation of energy policies, both at national and international level, within the broader region of South-East Europe. These policies focus on rationalizing the production and utilization of both conventional and renewable sources of energy. IENE is thus contributing towards the implementation of the European Union's sustainable strategy which combines social and economic development, security of supply and environmental protection. The Institute aspires to play a significant role in providing factual and unbiased information to professionals and to a broader audience alike on subjects concerning energy, the environment and sustainable development. Through an expansion of its partnership base in 2020/2021 IENE is now representing 13 counties of the region and can be truly regarded as a regional entity. Further information on the Institute, its mission, its objectives and its activities can be found in **www.iene.eu**

SE Europe Energy Outlook 2021/22
An IENE Study Project, M48
ISBN: 978-960-999940-5-7

Institute of Energy for S.E. Europe (IENE)
3, Alex. Soutsou, 106 71 Athens, Greece
tel: 0030 210 3628457, 3640278 fax: 0030 210 3646144
www.iene.eu, e-mail: secretariat@iene.gr

Summary of Contents



Contents

* Throughout this Study, this designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.

Acknowledgements

Several people have worked to make this study happen and therefore deserve a fair mention. Indeed, all study contributors, authors, peer reviewers and support staff are fully listed and acknowledged in the appropriate sections of the report. I wish to sincerely thank all of them for their most valuable input.

Special thanks go to Mr. Dimitris Mezartasoglou, who in addition to being a key study contributor acted as Associate Editor, often facilitating me through his timely intervention and tireless work in compiling and sorting out what at times appeared to be a mountain of papers and a meander of electronic files. In addition to the above and as project coordinator I wish to acknowledge with thanks the continuous encouragement and moral support provided by IENE's past Chairman Mr. John Chadjivassiliadis, a Peer Reviewer himself and by Mr. Christos Dimas, an IENE partner and Chairman of IENE's Geopolitical Committee who also acted as Peer Reviewer. Special thanks also go to Ms. Mary Mavrogeni in charge of IENE's accounts department. She helped me selflessly and in a very determined way to overcome several hurdles in the arduous path of raising the necessary funding which allowed the realization and publication of the study.

Finally, I want to sincerely thank all IENE staff who work in our offices in Athens for their important contribution and patience in dealing with my endless information requests and pressing communication demands.

Costis Stambolis

Executive Director, Institute of Energy for SE Europe (IENE)

Preface

The present "Energy Outlook" study for South East Europe is the third of its kind to be published by IENE in the space of a decade, signifying the Institute's strong commitment to a comprehensive approach when it comes to examining the region's diverse energy landscape. The first embryonic 'Outlook' study was released in the summer of 2011 and the second, far better organised with enriched content and a broader team of contributors was published in May 2017.

Now, following almost two years of intense preparation the third edition of the "SEE Energy Outlook", dated 2021/2022, is out and contains a compendium of facts and a review of latest activities backed by exhaustive data and analysis on the energy situation in the region. The publication would have been published 12 months ago but COVID-19 related complications in data collection and in the analysis phase prevented the IENE team from moving much faster. Despite the delay the 'Outlook' is still timely as several of the major energy issues discussed and presented, such as electricity and gas market integration, electricity and gas grid expansion, the higher penetration of renewables in the energy mix, the region's decarbonisation process, improvement in energy efficiency and the increasingly important role of technology are still very relevant, and hence a discussion backed by detailed data is most timely.

Because of the considerable delay experienced in producing this work with most country profiles submitted by the summer of 2020 energy data from most countries uses 2018 as a reference year. In several cases we have managed to include latest data covering 2019 and 2020. When it comes to electricity and gas prices and in view of major market anomalies experienced in the second half of 2021, we have included a whole Addendum to the Electricity section (See Chapter 10) where all latest moves on prices are discussed.

The present edition of the "SEE Energy Outlook" is expanded in terms of content compared to the last edition, as it includes profiles of two more countries and one extra sector (technology). So, a total of 15 countries from the broader region are covered through dedicated Country Profiles with several well researched topic areas also included. The inclusion of Hungary and Israel in the present 'Outlook' edition completes our informed energy perspective of the region, in the sense that Hungary over the last few years has emerged as key regional electricity hub for SEE, while Israel which has of late become an important gas producer is already impacting energy flows in the region.

The great bulk of the Outlook's content is original in concept and writing and is based on contributions from 29 experts from all different countries in the region and their names and CV's appear in the first pages of the Outlook. Of great importance too is the work undertaken by the Peer Reviewers whose names and brief biodata is also included. Tremendous effort was also made by the Institute's in-house research team who had to accommodate work on this project with a busy schedule related to analysis work, ongoing surveys, project assessment and the preparation of IENE's regular information feed to its members. It is going without saying that both myself and the Institute are much indebted to them for their enthusiasm and commitment in undertaking and completing under duress the agreed assignments.

Funding for the preparation and publication of this voluminous work came from a group of 16 energy companies who acted as sponsors and supporters,mostly from Greece but also from Bulgaria and Turkey. It is fair to say that without their valuable support and generosity publication of this 'Outllook' study would not have materialised. On behalf of IENE I sincerely wish to thank them for entrusting the Institute and for actively supporting this project, which in essence is a truly regional collaborative effort, culminating in what turned out to be a major reference study.

Costis Stambolis
Editor

Athens, December 2021

Study Contributors

EditorialTeam

Editor: Costis Stambolis
Associate Editor: Dimitris Mezartasoglou
Assistant Editor: John Psaropoulos

Authors

Abaz Aliko
Adam Balogh
Giannis Bassias
Dimtris Bimpas
Vesna Borozan
Robert Bosnjak
Shkelqim Bozgo
Matjaz Cesen
Anthi Charalambous
Gina Cohen
Rocco DeMiglio
George Giannakidis
Eugenia Gusilov
Fadil Ismajli
Miki Korner
Alexandros Koutroumpousis
Dimitris Mezartasoglou
Mihailo Mihailovic
Aleksandar Mijuskovic
Gus Papamichalopoulos
Anna-Maria Papamichalopoulos
Alexandros Perellis
Mirsad Sabanovic
Nikos Sofianos
Costis Stambolis
Kaloyan Staykov
Irene Terzidou
Costas Theofylaktos
Yurdakul Yigitgüden

Study Organisation

Project Co-ordinator: Costis Stambolis
Secretariat and research support: Ms. Eleni Myrilla
Marketing: Mrs. Katerina Stergiou

Authors per Chapter

Executive Summary
By the IENE Team

Chapter 1
Introduction
Costis Stambolis, Executive Director IENE, Outlook Editor

Chapter 2
Regional Economic Outlook
Dimitris Mezartasoglou, Research Fellow IENE

Chapter 3
EU Energy and Environmental Policies and Regional Priorities
Dimitris Mezartasoglou

Chapter 4
Key Regional Energy Issues
Costis Stambolis
Dimitris Mezartasoglou

Chapter 5
Country Profiles

Albania
- Shkelqim Bozgo, Managing Partner, SEA-Consulting, Albania
- Abaz Aliko, Founding Member, SEA-Consulting, Albania

Bosnia and Herzegovina
Mirsad Sabanovic, Director, ASA Energija, Bosnia and Herzegovina

Bulgaria
Kaloyan Staykov, Chief Economist, Energy Management Institute (EMI), Bulgaria

Croatia
Robert Bosnjak, Energy Expert, EIHP, Croatia

Cyprus
Anthi Charalambous, Director of Energy & Environment, Cyprus Employers & Industrialists Federation (OEB), Nicosia, Cyprus

Greece
Dimitris Mezartasoglou

Hungary
Adam Balogh, MBA, Senior Energy Infrastructure Expert, Energy Community, Austria

Israel
- Gina Cohen, Consultant to the Natural Gas Market and Lecturer at Technion University, Israel
- Miki Korner, Chief Economist at MNI, Israel

Kosovo
Fadil Ismajli, CEO, New Kosovo Electricity Company (NKEC), Kosovo

Montenegro
Aleksandar Mijuskovic, Chairman of the BoD, CGES, Montenegro

North Macedonia
Vesna Borozan, Professor of Power Systems, University "Sts. Cyril and Methodius", Faculty of Electrical Engineering and Information Technologies, North Macedonia

Romania
Eugenia Gusilov, Director, Romania Energy Center (ROEC), Romania

Serbia
Mihailo Mihailovic, Independent Energy Consultant, former Head of PE Electric Power Industry of Serbia, Serbia

Slovenia
Matjaz Cesen, Advisor, Jozef Stefan Institute, Slovenia

Turkey
Yurdakul Yigitgüden, Independent Energy Consultant, (F) Co-ordinator of OSCE Economic and Environmental Activities, (F) Under-Secretary of Energy and Natural Resources, Turkey

Chapter 6

The Peripheral Countries

Dimitris Mezartasoglou

Chapter 7

The Legal Framework of the Energy Market in SE Europe

- Gus Papamichalopoulos, Senior Partner, Head of Energy, Utilities & Infrastructure, KG Law Firm, Greece
- Anna-Maria Papamichalopoulou, Junior Associate, Energy, Utilities & Infrastructure, KG Law Firm, Greece

Chapter 8

Hydrocarbon Exploration and Production in SE Europe

Dr. Yannis Bassias, Energy Consultant, former Chairman and CEO, Hellenic Hydrocarbon Resources Management (HHRM), Greece

Chapter 9

The Oil and Gas Sector

9.1 Oil Midstream and Downstream

- Irene Terzidou, Research Fellow IENE, Greece

9.2 Gas Market

- Alexandros Koutroumpousis, Director of Large & Medium Business Customers at PPC S.A., Former Head of Energy Markets at DEPA, Greece

Chapter 10

The Electricity Sector

Alexandros Perellis, Research Fellow IENE, Greece

Chapter 11

Renewable Energy Sources

Nikos Sofianos, Independent Energy Consultant, Research Associate IENE, Chairman of IENE's RES Committee, Greece

Chapter 12

Energy Efficiency and Cogeneration of Heat and Power in SE Europe

Costas Theofylaktos, Secretary General IENE, Chairman of IENE's Energy Efficiency Committee, Greece

Chapter 13

Energy Technology Perspectives in SE Europe

- Costis Stambolis
- Dimitris Mezartasoglou

Chapter 14

Energy Demand and Supply Projections for SE Europe

- Dr. George Giannakidis, Senior Energy Consultant, Greece
- Rocco DeMiglio, Energy Systems Analyst and Modeler, Italy
  Energy Consultant, Greece

Chapter 15

Investment Potential in the Energy Sector of SE Europe

- Dimitris Bimpas, Scientific Advisor at Economic and Social Council of Greece (OKE), Greece
- Dimitris Mezartasoglou
- Costis Stambolis

Chapter 16

Key Messages

By the IENE Team

Contributor Resumes

Dr. Abaz Aliko

Dr. Abaz Aliko is a senior economist with a strong academic background. He has been Commissioner at the Albanian energy regulator Director at the Albanian Central Tax Authority active member of high local government bodies lecturer of a few universities as well as freelance financial and business consultant and is actually a partner of SEA Consulting. His area of expertise include: Identification and assessment of business cases in the area of RES and power sector Energy sectorregulation pricing and tariff methodologies and their practical implementation. Determination of the allowed expenses for the regulated tariffs of the regulated companies in the energy sector. Review of the investment plans of regulated companies.Market model of the electricity sector. Market rules network codes and connections to the greed. Capacity allocation contracts for different market participants.Review and development of PowerSector acts including natural gas and renewables. Support schemes for renewables. Analysis of long-term developments in the sector and possible options. In depth knowledge of the tax syste. Lecturing on economics and finance. Strong negotiation skills. Mr. Aliko was born in Gjirokastra Albania. He has a Ph.D. in economics and agriculture policy by the Agriculture University of Tirana.

Adam Balogh

Adam Balogh has an MA in economics from the University of Szeged in Hungary and an MBA specialised in energy, from the Vienna University of Economics, Austria. Currently he is a senior energy infrastructure expert at the Energy Community Secretariat in Vienna, Austria, where he deals with the socio-economic assessment of large gas infrastructure projects, potential of hydrogen technologies and energy legislation and regulation. Previous positions of Adam include: Adviser - European Network of Transmission System Operators for Gas – ENTSOG in Brussels, dealing with the European Ten Year Network Development Plan and projects' Cost-Benefit Analysis; Business Development Expert - FGSZ Ltd., the Hungarian Gas TSO, Controller - Exxon Mobil

Dr. Yannis Basssias

Dr. Yannis Basssias has 35 years of experience in the international oil and gas industry. From 2016 to 2020, he served the Greek State as President & CEO of HHRM (Hellenic Hydrocarbon Resources Management), handling the oil & gas E & P activities and supervising the offshore safety regulations. He was member of the National Commttee of Energy and Climate (ESEK) policy group of Greece in 2018 and 2019 and since 2021 he assists municipalities in West Macedonia in their decarbonisation plans and is also involved in the LNG area. From 2012 to 2016, he advised international companies in the EEZs of the Indian Ocean, Equatorial America and West Africa on geological and legal aspects of frontier hydrocarbon basins. From 1991 to 2012, as CEO and president of the group Georex, he demerged the hydrocarbon assets from the service activities of the group establishing technical subsidiaries in France, United Kingdom, Tunisia and the Republic of Congo. He handled upstream projects for the CIS, Total, Elf, SNPC and Esso and between 1996 and 2000 he directed evaluation teams for oil and gas interests in Texas and Colombia. Before joining the petroleum industry, from 1985 to 1991, Mr. Bassias had an academic career at the Free University of Berlin and then as Associate Professor in the Marine Geology Department of the National Museum of Natural History in Paris focusing in the Indian Ocean petroleum bearing basins. He graduated from the Kapodistrian University in Athens, he holds a PhD in geology from the University of P. & M. Curie in Paris and has studied in Management-Negotation and Corpoarte Financing in Paris.

Dimitris Bimpas

Dimitris Bimpas is an economist. Currently he is scientific advisor, at the Economic and Social Council of Greece (OKE), and he is also a member of the experts' network of the Academy Avignon for Crafts and SMEs He has worked as Research Associate, and Economist, at the Division of Economic Analysis & SMEs, at the Small Enterprise's Institute (IME) of GSEVEE. He has been a Scientific advisor to the General Secretariat of the Ministry of Development of Hellenic Republic where he specialized on SMEs policies, strategic investments, sustainable development, health care policies and health tourism. He also contributes regularly to IENE projects where he holds the position of Research Fellow. He holds a BSc in Economics (University of Macedonia, Thessalonica), an MSc in Economic and Social Policy Analysis (University of York, UK), and an MPhil in Economic Sciences (National and Kapodistrian University, Athens).

Stefan Borozan

Stefan Borozan received his BSc degree in Electrical Engineering and Information Technologies from Ss. Cyril and Methodius University in Skopje, North Macedonia, in 2017, and his MSc degree in Future Power Networks from Imperial College London, United Kingdom, in 2018. Since then, he has continuously held a position as a visiting research associate in the Faculty of Electrical and Electronic Engineering in Skopje, and in 2019 he worked as a New Customer Connections Project Manager at the largest distribution system operator in North Macedonia, Elektrodistribucija DOOEL (part of EVN Group). Currently, he is a researcher in the Department of Electrical and Electronic Engineering at Imperial College London, working towards the PhD degree.

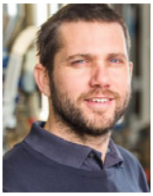
Robert Bosnjak

Over twenty years, Robert Bosnjak has been actively involved in gas market development projects in South East Europe dealing with energy consumption and gas and heat system development aspects: Energy consumption analyses, Energy consumption forecasting, gas and heat network development projects planning, pre-feasibility and feasibility studies development. Soon after gaining a Master's degree in petroleum engineering Robert was employed in Energy Institute Hrvoje Pozar in Croatia. He left the Institute from the Deputy Head of Energy Systems Planning Department position. Currently, Mr Bosnjak holds a position as Head of Strategic Development Department in Plinacro, the Croatian gas TSO. During his professional carrier he participated in several advanced trainings of which the FOIP – business and company development – Preparation and evaluation of investment projects, RUHRGAS Gas Distribution System Planning Software and Market Research, Information and Optimisation System training, IAEA expert MAED – Model for Analysis of Energy demand training and ENERDATA s.a. in France. Demand Forecasting and Energy Efficiency Evaluation are the most important training seminars which he attended.

Shkëlqim Bozgo

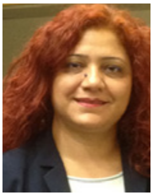
Shkëlqim Bozgo is a petroleum engineer and senior executive with nearly three decades of work experience mostly managing large and medium size commercial and non-for profit organizations in complex and multicultural environments. He has rich experience in the energy sector and particularly with the emerging natural gas markets and infrastructure in Albania, Kosovo and the Energy Community region. As member of the Board of Commissioners he has lead the Albanian Energy Regulator's work in the joint process of the Energy Regulators of Greece (RAE), Italy (ARERA) and Albania (ERE) for awarding the conditional exemption from the third party access to the natural gas interconnector Trans Adriatic Pipeline (TAP). He is the author of several regulatory documents and pre-feasibility studies for the Albanian and Kosovo natural gas sector and remains active with the natural gas sector developments issues in the Energy Community and wider. Shkëlqim has also extensive international experience including PSA negotiations with IOC, implementation of EU funded projects and as the ERE representative in the Energy Community Regulatory Board and its elected President (2012-2013). He was the Albania Country Manager of the mega project Trans Adriatic Pipeline and is currently the Managing Partner of SEA-Consulting.

Matjaz Cesen



Matjaz Cesen, has a BsC in Meteorology, and he is a researcher at the Jozef Stefan Institute – Centre for Energy Efficiency. His research interests are particularly related to energy consumption and supply modelling and simulation and emissions modelling, analysis of statistical data, energy indicators, decomposition analysis, statistical analysis and climate, air pollution and energy policy decision support methods. He has actively participated in research projects related to energy modelling, emissions modelling, analysis of energy consumption in households and transport, evaluation of effect of different measures on energy consumption and emissions, evaluation of proposed targets for Slovenia and their potential for their achievement and review of emission inventories. He also participated in the review of national communications and biennial reports under UNFCCC. He is also a lead reviewer and in several EU projects.

Anthi Charalambous



Anthi Charalambous is a Chemical Engineer having graduated from the National Technical University of Athens (NTUA), with specialization in Environmental Engineering (MSc). She also holds a Masters in Business Administration (MBA) and P.Dip. in Renewable Energy and Energy Management. At the beginning of her career (1997) she worked abroad in environmental projects, environmental impact assessment studies, in the management and processing of liquid and solid wastes and in designing biomass to energy plants. In 2001 she started working in the field of renewable energy and energy saving at the Cyprus Institute of Energy and in 2004 she was appointed Energy Attaché in the Permanent Representation of Cyprus at the EU in Brussels. In 2007 she joined the European Commission's Directorate-General for Energy (DG ENER) working in the renewable energy technologies Unit. During 2009 – 2015 she was the Director of the Cyprus Energy Agency. She has participated in many conferences in Cyprus and abroad as an invited speaker and she has published widely on RES and Energy Efficiency. She was the Secretary of the Cyprus Association of Chemical Engineers for the period 2010-2012 and a member of the Committee on Energy Policy in the Scientific and Technical Chamber of Cyprus (ETEK) for the period 2009-2014. In 2016 she joined the Cyprus Employers and Industrialists Federation (OEB) as the Head of the Energy & Environment Division.

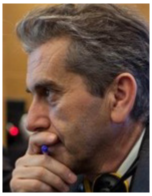
Dr. Gina Cohen

Dr. Gina Cohen has been working as a natural gas analyst and consultant in the Eastern Mediterranean for more than two decades, with a focus on Israel, Jordan, Cyprus, Turkey, Egypt and the Palestinian Authority.During her many years of work in the energy sector, she has been involved in projects spanning the full natural gas chain: from exploration & development, gas legislation and regulation, Gas Sales and Purchase negotiations, independent power generation and FLNG projects, permitting for the Israeli gas offshore facilities, etc. Gina is a lecturer at the graduate school for Petroleum Engineers at the Technion University in Israel and at Cyprus University Department of Civil and E nvironmental Engineering, and often speaks in many international gas conferences. Gina Gohen is the author of the energy lexicon (www.hebrewenergy.com) and a book published by IENE entitled "Long Term Gas Contracting".

Rocco De Miglio

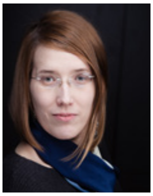
Rocco De Miglio is an Industrial and Management Engineer, with extensive experience in the development of decision support system tools, in the application of different modelling techniques, and in the preparation and analysis of energy-climate strategies and plans. He works as an individual Senior International Expert for consulting services and technical assistance on energy-climate analyses and on modelling activities (he has experience in several EU Member States, Egypt, Ukraine, Moldova, Jamaica, Central Asia). He is the lead architect of the energy system models for Kazakhstan, and for the Central Asian Caspian countries, and of their dedicated stakeholder engagement dashboards. He is the author of a number of publications and studies about energy & emissions-related analyses.

Dr. George Giannakidis



Dr. George Giannakidis worked initially as a senior consultant and then as the Head of Energy Systems Analysis Laboratory in the Centre for Renewable Energy Sources and Saving (CRES), Greece for a total of nineteen years. Since 2016 he is working as a freelance Energy Consultant. He has more than twenty years of professional experience in the sectors of renewable energy, energy efficiency, energy planning, energy modelling, energy systems analysis and energy statistics. He has worked in Eastern European countries, in the Middle East, Africa and the Caribbean on energy planning issues, with a focus on the development of energy strategy using energy system models. He is actively involved in the Energy Technology Systems Analysis Project (ETSAP) TCP of the IEA as the Operating agent (2012 - 2016) and Project Head (2017-today).

Eugenia Gusilov



Eugenia Gusilov is the founder of the think tank Romania Energy Center (ROEC). She specializes in energy economics and has worked with NATO, the UN, the World Bank, IFC, Energy Charter, the Romanian Ministry of EU funds, companies, embassies, universities and NGOs on a wide range of policy and commercial projects. Eugenia started out as an analyst for the Romanian Diplomatic Institute, Romanian Ministry of Foreign Affairs, where she covered natural gas developments in Russia, Belarus, and Ukraine (2005-2008). She is a frequent speaker at energy events in Romania as well abroad, with presentations on topics as diverse as Romanian energy policy, Black Sea gas, EU energy law, district heating or energy transition.She holds a MA with a concentration in International Energy Management and Policy from Columbia University in New York (USA, 2010) and a BA in European Studies from Bucharest University (2005). She was a recipient of the Fulbright award (2008). Since 2020 she is a partner of IENE and Member of the Board of Governors.

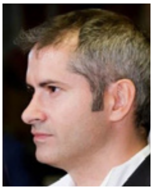
Fadil Ismajli

Fadil Ismajli is an economist and currently serves as CEO of the New Kosovo Energy Corporation monitoring the construction of a 500MW coal fired power plant. He worked with USAID as Executive Director of cross-border transmission project CASA-1000 (1300km AC/DC facility linking Central/South Asia). In 2013-2014, he held the post of Minister of Economic Development of Kosovo. During 2006-2013, he worked as the CEO of KOSTT. In 2005, he led the unbundling of the Kosovo Electricity Corporation (KEK). He helped establish the Kosovo Electricity Transmission, System and Market Operator (KOSTT J.S.C.). In 2003-2005, he worked in private sector and in 2001 he was chairman of KEK. He has participated in in several regional and EU energy bodies. He managed numerous projects in the private sector, both on IT and energy. He has graduated in economics from the University of Prishtina. and attended post-graduate studies in Economic Analyses at the University of Zagreb, while he took numerous professional courses in Croatia, Switzerland, Germany, USA etc. He has published a number of papers in the broad area of energy, economics and IT. He is an IENE partner and member of IENE's Board of Governors

Miki Korner

Miki Korner is mechanical engineer with a B. Sc. from Tel Aviv University. He holds an M.B.A. ¬ from the TAU & Wharton business Schools and he has also a graduate diploma in Regulatory Studies – NAURC, from the University of Michigan. He is an ex-regulator (NAURC), with diverse experience in hi-tec and industries. Between 2004-2009 he was Deputy Manager & Chief economist of the NGA/ Energy Ministry. Since 2010 he has established his own a consulting firm undertaking tech-economics & regulation assignments, supporting entrepreneurs, upstream/midstream gas companies, IPPs', financial institutes, industries, and government. Miki is also teaching at MBA degree courses in Israel and works as an evaluator for technology companies optical devices, AI, machine learning, Industry 4.0 etc.

Alexandros Koutroumbousis



Alexandros Koutroumbousis is a Mechanical Engineer (Meng), a graduate of the National Technical University of Athens (1999) and holds an MSc Degree in Production & Energy Management from the National Technical University of Athens (2003). He also holds a professional practice license from the Technical Chamber of Greece. Since December 2001 he has been appointed to several positions in energy companies (Public Gas Corporation S.A., Ergaz S.A., Attika Gas Supply Company S.A., Natural Gas Hellenic Energy Company S.A.) with responsibilities including commercial policy design, engineering-construction-procurement (ECP) of natural gas installations in Industry/Commercial customers, development and key accounts management, energy markets regulation and policy development/compliance, design and development of sales channels, customer experience teams in retail and wholesale natural gas & electricity markets. He has published in the scientific magazine of the Society of Automotive Engineering (SAE) in the area of computational combustion models application for reciprocating internal combustion engines (2001-2002). He is a contributor to IENE's flagship publication 'South East Europe Energy Outlook' and in IENE's annual report and member of IENE's Scientific Committee for Natural Gas, Biomethane & Hydrogen. He often contributes to IENE projects as a Research Associate. Since November 2020, he has been appointed as the Head for Large & Medium Corporate Customers Sales in Public Power Corporation S.A.

Dimitris Mezartasoglou

Dimitris Mezartasoglou is an energy analyst with more than 7 years of working experience. He is a graduate from the Department of Economics in University of Peloponnese, while he holds two Master's degrees from the University of Strathclyde on Global Energy Management and from the University of Exeter on Money and Banking. He has full exposure across the energy sector, specifically for Greece and SE Europe. His research interests include the economics of European and SEE's energy integration and energy policy making, including gas, renewable energy sources and energy efficiency sectors as well as energy poverty issues. Currently, he works as Energy Economist in Energy Policy Department at the Center for Renewable Energy Resources and Saving (CRES). As part of IENE's Research Team since 2015 he has contributed to various studies and analyses, while he has also overseen the Institute's newsletters.

Mihailo Mihailovic

Mihailo Mihailovic has over 35 years of professional and business experience in the Power Industry of the Republic of Serbia. He possesses extensive knowledge and skills in covering national electricity system dispatching, short and long term operation planning and long term corporate strategic planning. As an evaluator of new energy concepts and technologies, he was involved in the energy strategy development and market projections, along with policy related activities on both national and regional levels. During his career, he was a cross–functional leader in strategic planning, mapping potential and reviewing RES output in the power industry on company, national and regional level. He is a team leader for harmonization and implementation of modern energy statistical methodologies.Contributing editor on energy developments and trends in Serbia and SEE countries for the European annual publications.Mihailo has also authored or co-authored numerous papers and presentations in international conferences and he was a reviewer on many national and regional policy studies regarding energy efficiency, climate-energy changes and regional electricity market development.Mihailo graduated and received his M.Sc. degree in Power Engineering from the Faculty of Electrical Engineering at University of Belgrade. After retiring from his position at the Electric Power Industry (EPS) of Serbia, he has worked as an independent energy consultant and has been appointed as a Partner and member of the IENE's Board of Govenors.

Aleksandar Mijušković

Aleksandar Mijušković, is an electrical engineer and currently serves as the president of the Board of Directors of Montenegrin TSO (CGES Podgorica). Prior to that he worked for the Coordinated Auction Office in South East Europe (2014-2021) and within the period from 2014 to 2019 was the Executive Director. He held the office of the Executive Director of the Project Team Company in charge of establishing SEE CAO from 2012 to 2014. From 1995 to 2009 he was employed with Electric Power Enterprise of Montenegro as an engineer within National Dispatch Centre and from 2009 to 2012 as a director of Department for Regulatory, Legal and International Affairs within Montenegrin TSO. His international involvement include the following positions of Member of: ENTSO-E Market Committee (2009-2012), SETSO Task Force (2003-2009), EURELECTRIC Ad-hoc Working Group (2004-2007), EPCG-TERNA negotiation team on the undersea interconnection between Montenegro and Italy and Montenegrin Delegation: at the European Commission and at Montenegro sub-committee meetings (Brussel 2008, Podgorica 2009) and Participant in Athens Forum since 2003 and Participant in SEE ENERGY DIALOGUE – IENE since 2007 and partner of IENE since 2020.

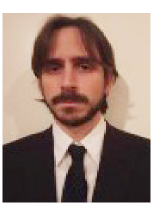
Gus Papamichalopoulos

Gus Papamichalopoulos heads the Energy, Infrastructure and Utilities Practice Group. His main area of expertise is on the energy industry and he has been involved in the liberalization of the Greek electricity market and gas market. Due to the complexity of the issues associated with the electricity market regulations he advises on major regulatory issues of the electricity, natural gas and RES market. As a business lawyer focusing on the energy sector, key international energy companies investing in Greece have mandated. Gus in the early stages of their investment program for the implementation of important energy projects (infrastructure projects such as oil and gas investments, the licensing and development of gas pipelines, the establishment of power generation plants, wind parks, low pressure gas distribution networks, etc). Another element of his practice is the public sector-privatization projects.Project finance is a strong section of his practice, since major local financial and credit institutions and private equity funds are instructing the team for the financing of energy infrastructure projects. Gus also serves as one of the managing partners of KG Law Firm, has acted as co-chair of SEE LEGAL Group for two years. He is a Partner of IENE and Member of the Board of Govenors and currently serves as Deputy Chairman of IENE. Gus Papamichalopoulos is ranked as a leading lawyer in the IFLR1000, Chambers & Partners Europe and Chambers & Partners Global.

Anna Maria Papamichalopoulou

Anna-Maria works for the Energy and Infrastructure practice group of lawyers at Kyriakides-Georgopoulos (KG) Law Firm. Anna-Maria graduated in law from Democritus University of Thrace in 2017 and was awarded an LLM in International Business Law by Queen Mary University of London in 2019, with an LLM Thesis (with distinction) on Green Bonds as a new a financing tool. Her practice focuses on corporate and M&A law in the energy sector and other industries. Anna-Maria also advices international energy companies in the early stages of developing their projects (infrastructure projects such as, oil and gas investments, licensing and development of power generation plants, etc.). She often provides legal advice to corporations in the energy sector with regard to various issues relating to their daily operation, drafting and reviewing various types of contracts and agreements and she is involved in due diligence procedures for mergers and acquisitions both at domestic and cross border level.

Alexandros Perellis

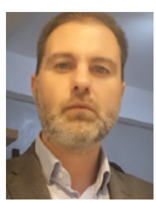


Alexandros Perellis is a graduate of Dpt. of Production Engineering and Management of Democritus University of Thrace's School of Engineering (DUTH) (2010). He also holds a MSc degree in Sustainable Energy Engineering from Technical University of Denmark (DTU) (2013). Currently he is an analyst at Energy Systems Analysis Laboratory of the Center for Renewable Energy Resources and Saving (CRES). Alexandros is a member of Technical Chamber of Greece and has a 5 year working experience in the energy sector, in which he was affiliated with projects regarding developing solar energy systems, modeling and analysis of sustainable energy systems, electricity market analyses and feasibility studies and system assessment of energy technologies. He currently works as an external Research Associate of IENE.. As part of his work at IENE he contributed to various studies and analyses, while he also compiled and edited the Institute's newsletters on regional electricity markets and electric mobility. He worked at IENE as Research Officer from 2017 until 2021.

Mirsad Sabanovic

Mirsad Sabanovic is currently the director of ASA Energija, a company that is a supplier of electricity and is engaged in the development of larger RES generation facilities in BiH. He is also engaged in regional projects related to the electricity market and market coupling projects. Mirsad Sabanovic was Executive Director for Supply and Trade of electricity and Member of Management Board (2011-2015) at the biggest power utility in BiH. During his professional career, he worked in several positions (Manager of Market Operation department in the Independent System Operator of BiH, manager of electricity wholesale department, dispatcher at the national control center).Mirsad has more than 25 years of experience in the electric power sector. He is the author and co-author of several professional papers and studies on electricity markets and the economics of electric power systems. He was a member of SETSO TF (SEE Transmission System Operator Task Force) and a few SETSO subgroups and ENTSO-E Market Committee and their SEE Regional Group. President of Study Committee C5 - Electricity Market of BH K CIGRE and since 2020 he is a partner and Member of the Board of Governors of the Institute of Energy for South East Europe (IENE).

Nickolas Sofianos



Nickolas Sofianos, holds an Mphil in Development Studies from the University of Glasgow in Scotland (2005). He is an independent energy consultant while he is a Partner and member of IENE's Board of Governors, and chairman of IENE's RES Committee. Over the years Mr. Sofianos has published several studies, reports and specialized papers on energy, economy and policy issues and contributed articles on energy, geopolitics and related subjects. He has authored, co-authored and edited several Studies and Research Papers. Through his research, he succeeded high level of expertise in collecting and analyzing energy and macroeconomic indicators and other statistical data. He worked initially as research coordinator and then as a Senior Research Associate at the IENE from 2008 until 2017. He has served as Energy Consultant and Development Economist expert, providing advisory services to large institutional clients (ministries, regulatory authorities, associations) and companies in the energy policy, oil, gas, electricity and RES sectors, while he participated in several working groups with the main goal to promote climate change policies, decarbonization processes and clean coal technologies. As an energy expert, he specializes in relations between governments and companies with a focus on energy, environmental, and public sensitive issues. Over the years Nicholas co-operated with various public and private institutions and organizations in the whole SE European region (ministries, organizations, regulator authorities, NGO's, associations, companies etc.) acting several times as a bridge between companies and governments in SE Europe in order to facilitate interaction between them and market openness. He also deals with the investment part of energy as he participates in several photovoltaic projects but also in the field of biogas.

Costis Stambolis

Costis Stambolis is the Executive Director of IENE and currently serves as IENE's elected chairman. Costis has a background in Physics and Architecture having studied at the University of London, the North East London Polytechnic (NELP) and the Architectural Association in London from where he holds a Graduate Diploma in Architecture and Energy Studies (AA Dip. Grad). He also holds a professional practice license from the Technical Chamber of Greece (TEE), and a Masters Degree from the Said Business School, University of Oxford, where he studied "Strategy and Innovation". He has worked as a consultant and strategy advisor on natural gas, oil markets and energy security issues for large multinational companies, international organizations and governments. He has lectured widely on energy issues and has organised several national, regional and international conferences, seminars and workshops. He has published several books, conference proceedings, research papers and studies on energy policy, solar energy. Since 2001 he supervises and edits daily Greece's foremost energy site www.energia.gr. He is a founding member of the Institute of Energy for South East Europe (IENE), which he currently chairs. He is a member of the Energy Institute (UK), the International Passive House Association (IPHA), The Technical Chamber of Greece (TEE). Since 2018 he is a full member of the Greek government's standing committee on Energy and Climate Change (NECP).

Kaloyan Staykov

Kaloyan Staykov has been the Chief Economist at the Energy Management Institute since July 2021. Prior to that, for ten years, he has worked as an economist at the Institute for Market Economics in Sofia, where he dealt with analyses in the field of public finance, energy, business environment, healthcare, and other. Prior to joining the IME team, he worked as an economist at the Center for Economic Development. He is part of a group of experts and economists who have been pushing for years to increase competition in the energy sector until its full liberalization. He is the author of a number of publications and analyses in this direction, including: "Integration of electricity producers with long-term contracts on the market" and "Regulatory policy in the electricity sector in 2013 - contrary to regulations and common sense."He is a member and deputy chairman of the Bulgarian Macroeconomic Association. PhD candidate at the Faculty of Economics, Sofia University "St. Kliment Ohridski". He holds a Master's degree in Economics and Management in Energy, Infrastructure and Utilities from Sofia University "St. Kliment Ohridski", and a Bachelor's degree in International Economics and Business with a specialization in Finance from the University of Amsterdam, the Netherlands.

Terzidou Eirini

Terzidou Eirini joined IENE in 2021. She is a graduate from the department of Chemical Engineering of Aristotle University of Thessaloniki and holds an MSc degree in Environmental Technology from the University of Manchester Institute of Science and Technology (UMIST) and a Master of Business Administration (MBA) from the European University of Cyprus. Eirini has strong background related to the environment and energy sector. In 2013, she was hired by the Centre for Renewable Energy Sources (CRES) to be involved in the licensing process of renewable energy sources (RES) projects (issuing production/installation/operation license) for the Department of Renewable energy sources at the Ministry of Environment, Energy and Climate Change. She was also responsible for providing information to investors on the institutional, legislative, fiscal and financing framework necessary for the licensing procedures for investments in RES. In addition, she has worked in the area of management systems, especially in designing and implementing quality and environmental management systems (ISO 9001/ISO 14001) in different kind of companies. Eirini has also conducted sectorial studies in the field of renewable energy sources, waste management and recycling. She currently works at IENE as Research Fellow in charge of ESG, Green Bonds, energy & employment and related issues

Costas Theofylaktos

Costas Theofylaktos is a USA trained Mechanical Engineer with an MSc from the University of Evansville, Indiana, and has 30 years experience in the energy sector. Costas's special interests include energy efficiency, cogeneration and RES. He was for many years chairman of Hellenic Association for CHP and also member of the executive committee of COGEN Europe. He has served as chairman and CEO of the Athens based Centre of Renewable Energy Sources and Saving (CRES). He has participated as invited speaker in several conferences and seminars, and he has considerable experience in lecturing on energy efficiency techniques. He has worked globally as a senior consultant for several organisations including the EU, World Bank, EBRD, the Energy Community ao,. He is a Partner and Member of the Board of Governors of IENE where he is Secretary General of the Institute and also chairs the Energy Efficiency Committee.

Dr. Halil Yurdakul Yigitgüden

Dr. Halil Yurdakul Yigitgüden is an independent consultant specialising on energy economics and he is also a non-executive Board Member of CHS. From 2013-2017 he served as the Co-ordinator of OSCE Economic and Environmental Activities in Vienna. Between 2004-2012 he advised several international companies on investment climate and geopolitics in the region and was Board Member of BorusanMannesman (2007-2013), BorusanEnBW Energy (2008-2012) in Istanbul and Senior Policy Expert of the EU MED-ENEC project promoting solar energy and energy efficiency in ten Mediterranean countries (2006-2008). From 1997-2003 he served as Undersecretary of the Turkish Ministry of Energy and Natural Resources. He took a leadership role in the Caspian region energy diplomacy and in implementing energy market reforms in Turkey. From 1995-1997 he held the position of CEO of Fenis Holding in Istanbul. Prior to that he served as chairman and director general of the State Airports and Air Traffic Authority (1992-94); as deputy under-secretary of the Ministry of Transport and Communications (1991-92); as vice-president of the mining chemicals and banking Group Etibank (1989-91) and as group manager for Investment Promotion at the State Planning Organization (1987-89).

Peer Reviewers

A small number of academics, senior experts and company executives between them undertook the peer review of the report. Some of them read whole chapters and offered specific comments, corrections and advised on new input. Others contributed valuable advice on the structuring of individual chapters and the report as a whole. Their ideas, suggestions and critique proved of great value and vastly contributed to the improvement of the final Outlook report. We are indeed most grateful to all of them. They include the following:

Dr. Costas Balaras

Costas Balaras is a Mechanical Engineer with a degree from the Michigan Technological University (B.S.M.E) and has a PhD from the Georgia Institute of Technology. He is the leader of the Group Energy Conservation in IERSD at the National Observatory of Athens (NOA). He has been project coordinator, scientist-in-charge and participant in over 35 R&D and demonstration projects financed by the European Commission, national Ministries and organizations, and the private sector. His teaching covers renewable energy sources, rational use of energy, heat transfer, thermodynamics, fluid dynamics. Research Interests and accomplishments include: Research and development in the areas of renewable energy sources, energy conservation, thermal and solar building applications, building energy audits and building retrofitting, indoor environment, numerical modelling of thermal energy systems and building thermal simulations, HVAC installations, solar cooling, solar radiation and meteorological measurements and computer tool development.

John Chadjivassiliadis

He is Mechanical and Electrical Engineer of the NTUA (1960) and expert in the development of the renewable energy sources and sustainable power systems. He worked for the Public Power Corporation (1962-1990) in the department of power generation, where he was director of power plants, and project manager in large power plants. From the mid-1970s John was in charge of the development of wind and solar energy projects for power generation with the successful Windpark of Kythnos, the first in Europe (1982) and the biggest hybrid by wind and solar PV. Since 1990, he is a consultant engineer in energy, especially in the renewable energy sources, energy efficiency and sustainable development. For many years he served as an expert in evaluating research proposals and programs, coordinator and technical assistant of large research projects for RES integration into the networks within the European Commission research programs. John has been a scientific committee member in a number of European and international conferences, invited lecturer in international events and conferences where he presented over 80 papers. He is a founding Member of the European Wind Energy Association (EWEA, 1982), member of national and EU missions for international cooperation in scientific research and technology, founding Member and Secretary General of IENE, National Representative in the Mirror Group of the European PV Technology Platform, and Member of the Scientific Committee of the Hellenic Association of Mechanical and Electrical Engineers. John is the recipient of the "Prize Aeolus" Award, for his contribution in wind energy development by the Hellenic Wind Energy Association-member of EWEA (2009), as well as of the "2010 PES Chapter Outstanding Engineer" Award, for his contribution in renewable energy research and development by the IEEE Power & Energy Society, PES Greece Chapter. John was IENE's Chairman (2013-2019).

Dr. Spyros Chatzivasileiadis

Spyros Chatzivasileiadis is an Associate Professor at the Technical University of Denmark (DTU) and the Acting Group Leader of the Energy Analytics and Markets Group at the Center for Electric Power and Energy at DTU. He is a graduate in Electrical and Computer Engineering from the National Technical University of Athens (NTUA), Greece (2007) and he holds a PhD from ETH Zurich, Switzerland (2014).

Dr. Stavri Dhima

Stavri Dhima is an independent energy consultant based in Tirana, Albania. Until recently he was the Head of Primary Policies Sector and of the Unit, Regulatory and Managing Sector for Petroleum Projects, Contracts and the General Regulatory Directorate, at the Ministry of Economy, Trade and Energy in Albania. During 1979-1998 he worked at the Geophysical Enterprise and at the Oil and Gas Institute in Fieri, where he was the Director (1997-1998). He has a degree in Physics from the University of Tirana and a PhD in Geophysics (1997). Since 2001 he is an Associate Professor of Geophysics at Tirana University. Dr. Dima has contributed in the preparation of the legal and institutional framework for the Albanian oil and gas sector. He was the head of the inter-ministerial working group for the Law, responsible for security of gas supply. He is member of several professional and scientific associations. He has participated in numerus international conferences and meetings, where he has presented scientific papers and analysis. Dr. Dhima has also contributed various scientific monographs on the Albanian petroleum and energy sector and he has been the head of several working groups, for Energy and particularly for the Petroleum Sector in Albania. Stavri Dhima is a Partner of IENE and a Member of the Board of Governors.

Christodoulos (Christos) Dimas

Christos Dimas is a Land Surveyor and a Civil Engineer, having graduated from the National Technical University of Athens (1974). He has managed major projects on Energy, Industry & Infrastructure (Europe, Saudi Arabia, Russia). He was a senior executive and board member in various businesses and organizations (Petrola Hellas, Petrola International, Hellenic Petroleum, Helpe - Thraki, Trans Balkan, Construction companies, etc.) Christos Dimas represented the Greek Ministry of Development in international energy issues and participated in international conferences with presentations on the transport of oil and gas from Russia, Central Asia and the Caspian Sea to the international markets. He has held a number of executive positions including General Director of TBP B.V. (Burgas -Alexandroupolis Oil Pipeline) and Chief Executive Officer of TBP B.V. – Greece and General Manager of Helpe-Thraki SA. He was the President of the Hellenic-Russian Chamber of Commerce (2011-2017).He is a Founding Member and Partner of IENE, where he currently chairs the Geopolitics & Energy Committee.

Prof. Antonis Foskolos

Antonis Foskolos is an emeritus professor at the Technical University of Crete and an emeritus Researcher at the Geological Survey of Canada. He has worked for a number of years in the Institute of Sedimentary and Petroleum Geology of Canada and has taught at the School of Mineral Resources and Engineering at the University of Crete. He has published extensively in international journals and he has authored several special reposts for the Greek government and the UN.

Liana Gouta

Liana Gouta is the Director of Energy Policy & International Affairs at the HELLENIC PETROLEUM Group of Companies (HELPE). She holds a degree in Chemical Engineering, MSc, with Honors. She started her career as a process engineer in the Thessaloniki Industrial Complex of HELPE and she has many years of experience in several managerial positions, such as Energy Policy, Change Management, Operations and Process Design, Product Development, Environmental Management & Industrial Safety. She has also worked as Parliamentary Advisor to the European Parliament, on Industry, Energy and Environment. She is a member of the Board of Directors of the European e-Fuel Alliance, an alternate Board member of the European Petroleum Refiners Association and a Board member of HELPE Kyparissiakos Gulf SA. She is also Chairwoman of the Downstream Committee at the IENE-Institute of Energy for South - East Europe. She is active in associations and socially engaged in environmental issues, entrepreneurship, leadership and women's empowerment for many years.

Ivan Ichenko

Ivan is a petroleum geologist with more than 40 years of field experience. Among others he served for a number of years (1994-2000) as head of SE Europe and Mediterranean operations at 'Enterprise' (since acquired by Shell) and has considerable experience and knowledge of the geology of the Balkans and SE Europe. Until recently he was the head of Operations at Gazprom UK Resources, and an Executive Director and General Manager of Spike Exploration UK, an Upstream Oil and Gas Advisor.

Dr. John Kampouris

Dr. John Kampouris is an Electrical Engineer with Ph.D from the Technical University of Athens. He served for a number of years as General Director of Operations, Infrastructure and Development at the Independent Electricity Transmission Operator (IPTO) of Greece. Since May 2020 he is the CEO and Chairman of the Southeast Electricity Network Coordinator Center (SEleNeCC) which is headquartered in Thessaloniki.

Prof. Andrey Konoplyanik

Dr. Andrey A. Konoplyanik is an energy economist by background. His major professional areas include: energy economics, energy & investment legislation, energy financing. PhD (1978) & Dr. of Science (1995) in international energy economics, Professor in International Oil & Gas Business (2012). He is currently an Adviser to the Director General, Gazprom export LLC (since 2013) and Co-chair from Russian side of Work Stream 2 "Internal Markets", Russia-EU Gas Advisory Council (since 2011). He is Professor at the Chair "International Oil & Gas Business", Russian State Gubkin Oil & Gas University (since 2008). He is also an Honorary Fellow, Center for Energy, Petroleum and Mineral Law & Policy, University of Dundee, Scotland, UK (since 1994); Associate Member of the Institute of Energy for SE Europe (IENE), Athens, Greece (since 2015) and of the Center for Energy Law, University of Aberdeen, Scotland, UK (since 2018). Detailed professional biography of Prof. Dr. A.Konoplyanik, his publications, presentations and interviews are presented at www.konoplyanik.ru.

Konstantin Konstantinov

Konstantin Konstantinov is the CEO of the Independent Bulgarian Energy Exchange EAD (IBEX) since its establishment in 2014. He has a Master's degree in "Electrical engineering" from the Technical University of Sofia. He also holds a Master's degree in "International Business Relations" from the same university. Konstantinov has got a solid experience in energy sector. Prior to this role, he was an Electricity trade director at the Bulgarian electricity public provider - National electricity company EAD (NEK) and a member of the board of directors of NECO S.A.

Prof. Dimitrios Mavrakis

Professor Dimitrios Mavrakis is the Director of the Center for Energy Policy and Development (KEPA) at the National and Kapodistrian University of Athens. He is also coordinator of PROMITHEASnet, the Energy and Climate Change Policy Network, consisted of academic institutes from S.E. Europe, Black Sea and Central Asia. Furthermore, he is the coordinator of the "BSEC – Green Energy Network" focused on RES and Energy Efficiency for scientists, market stakeholders, and policy makers, mainly from the countries of BSEC.

Slavtcho Neykov

Slavtcho Neykov has more than 25 years non-interrupted experience in the energy sector, including as Secretary General of the Bulgarian Ministry of Energy, Commissioner in the State Energy Regulatory Commission, expert at the Energy Charter Secretariat in Brussels and a Director of the Energy Community Secretariat in Vienna. Prior to his involvement in the energy sector, he has worked as a state prosecutor and a legal advisor. In addition to a law degree from Sofia

University, Mr. Neykov has completed two years postgraduate studies on International Economic Relations and Foreign Economic Activities. He also holds a Master of Arts degree in European Integration from the University of Limerick in Ireland. Since the end of 2014, he is the Chairman of the Board of Managers of the Energy Management Institute (EMI). He is a partner of IENE and member of the Board of Governors.

Apostolos Petropoulos

Apostolos Petropoulos holds a Bachelor and Master degree in Electrical and Computer Engineering from the National Technical University of Athens. He has 8 years of experience in the energy sector participating in a number of European and country specific projects, with the main aim to assess policies and their impact on energy demand. As a previous member of the PRIMES Modelling Team, he was involved in numerous European Commission projects related to the transport sector and the biofuels market, using PRIMES-TREMOVE and PRIMES-Biomass models. He works at the World Energy Outlook of the IEA in Paris team preparing medium and long-term energy outlooks with particular emphasis on end use sectors since 2017. He leads the transport analysis with a particular focus on electro-mobility, demand response and battery demand.

Prof. Ionut Purica

Professor Ionut Purica is a senior researcher at the Romanian Academy's Institute for Economic Forecasting, and Executive Director of the Advisory Center for Energy and Environment, Dr.Purica was also a counselor of the Minister of Economy and previously the Minister of the Environment and an expert for the Parliament of Romania. He participated in the elaboration of the EU accession strategy for Romania and the energy (electricity and heat) strategy (for the Ministry of Economy and Trade) and enrolled on the risk analysis and transaction structuring and project management with the World Bank, USEA, JBIC, MARSH, ITOCHU, MVV, etc. Prof. Purica has authored books in his field of expertise e.g.(Imperial College Press, Academic Press, etc.) and published articles in journals like Risk Analysis, IEEE Power Engineering Review, Foundations of Control Engineering, Romanian Journal of Economic Forecasting, etc. He took his second PhD in economics, (the first one in Nuclear Energy Engineering) and, he is also Professor, teaching a course in Project Risk management to masters of science programs.

Nenad Stefanović

Nenad Stefanović is an Electrical Engineer and a senior expert for electricity at the Energy Agency of the Republic of Serbia (AERS). Since 2016 he is the President of the Study Commitiee of Electricity Markets and Regulation within the Serbian Committee of the International Council on Large Electric Systems (CIGRÉ). He is a regular contributor to international conferences and symposiums and the author of numerous papers. He has worked closely with IENE as a Research Associate on a number of projects.

Theodore Terzopoulos

Theodore Terzopoulos is a Chemical Engineer MSc (Politecnico di Milano), and also a Gas Engineer CEng (Institute of Gas Engineers, UK). He joined the Greek gas industry in 1989 and since then he has been continuously employed in all activities related to the gas distribution sector (construction, operation, maintenance of networks, billing, client's acquisition, management) as Director, Chief Director and General Manager. He has followed closely the introduction of natural gas to Greece and has contributed actively to the development of its gas grid. He was appointed CEO in two Gas Distribution Companies, namely EDA SA (2010-20212) and DEDA SA (2017-2018). Today he holds the position of Coordinating Director on Strategy & Corporate Affairs in DEDA SA. He holds severe professional affiliations including the Institution of Gas Engineers (Member), the Engineering Council (Charted Engineer), Eurogas Distribution Committee (Member), and GEODE, The Federation of European Distribution System Operators. Since 2020 he serves as Chairman of IENE's Natural Gas Committee.

Gokhan Yardim

Gokhan Yardim is a chemical engineer and currently he manages his own consulting firm ADG, Anadolu Natural Gas Trade and Consultancy Ltd. (www.adgltd.com.tr). In 1979, he started working as an operation engineer in the Maltepe Town Gas Factory of the Electricity, Gas and Autobus Authority of Ankara (EGO), where he was awarded an OECD grant in 1982 for onsite training on natural in British Gas Corporation in Britain. Since 1983 he has worked as an engineer in the General Directorate of BOTAS. (http://www.botas.gov.tr/) where he became a chief engineer, director, coordinator, department chief, General Manager and Chairman of the Board in Botas from 1983 to 2001. During his employment with BOTAS, he took part in various natural gas related projects, starting from preliminary studies for importing natural gas. In addition to natural gas purchases, he was also involved in the marketing and sale of natural gas and took part in the drafting and signing of intergovernmental and main contractor agreements regarding the BTC (Baku, Tbilisi, Ceyhan) Crude Oil Pipeline. In 2011, he was appointed as the general manager of Angoragaz Gaz Ticaret Sirketi. Angoragaz is a wholesale company holding a spot LNG import license, and has been operating as a key player in the Turkish natural gas market. It purchases natural gas from other wholesale companies and importers and sells it to distribution companies and industrial companies. For the past 3 years, Gokhan Yardim has been elected as Board Member of PETFORM (the Petroleum Platform Association) and since 2008, he has been an Associate of IENE having participated in several conferences and workshops for the Institute.

Milan Zdravkovic

Milan Zdravkovic is the assistant CEO for Economy at JP Srbijagas. He is a Mechanical Engineer with an MSc from the Dpt. of Aeronautics at the University of Belgrade, Serbia. Currently he is in charge of strategic development activities in the gasification programme of Serbia. He has also active cooperation with the international institutions including IGU, UNECE, DVGW, IENE, ECS, EC DG Energy, EC CESEC. He has acted as project leader in several JP SRBIJAGAS strategic projects including the Gas Interconnector Serbia – Bulgaria (Serbian part)

Executive Summary

One of the main challenges which IENE faced when it decided to embark, once again, upon this major regional project was the definition of the geographical area under examination. This became even more challenging as the contributors of the 2011 and 2017 studies (i.e. the first and second SEE Energy Outlook study which IENE published) as well as the current ones did not merely come from an interdisciplinary scientific background but also represented several states in the region, such as Albania, Bulgaria, Croatia, Cyprus, Serbia and Turkey to mention just few of them. Admittedly it is difficult, if not risky, to define SE Europe as a separate energy system as it is equally hard to think of it as a unified political sub-system of modern European geopolitics.

The finally-defined region is too diverse politically, culturally and economically in order to be "separated" from other far more culturally cohesive and politically distinct regions, such as the Middle East and the Former Soviet Union, geographical areas which also happen to contain states which are major oil and gas producers and hence energy exporters to SE Europe, and as such present both potential energy risks but also offer opportunities. Yet, this perennial diversity and complexity are some of the most common characteristics of the SEE region.

A region, which has been moving slowly, but steadily over the last 20 years or so towards a new path of economic prosperity, political democratization and geostrategic stability – if not yet – reconciliation, within a common European and Euro-Atlantic future.

The historical and political framework of the SEE region is detailed in **Chapter 1**, along with the role that energy can play in creating and deepening the economic synergies, which are necessary in order to keep the region both in peace and en route to a better and more integrated European future. In this context, the importance of the "Energy Community" is stressed together with the latest policy initiatives of the EU, such as the "Energy Union" and the new "Fit for 55" package. West Balkans is recognized as an area of special significance within the broader SEE region. However, the level of market liberalization and integration both within the area and between the

Map 1 **The SE European Area Defined***

*This comprise the 15-country group being examined in this Outlook study.
Source: IENE

[2] IEA (2018), "Energy in the Western Balkans – The Path to Reform and Reconstruction", https://iea.blob.core.windows.net/assets/6f3556ba-55bc-4d5b-927c-2d027fd2ebfb/Balkans2008.pdf

region defined by the EU Member States that surround it remains incomplete to the detriment of the region's economic/energy rehabilitation and the pace of its prospective inclusion into Euro-Atlantic institutions, and notably the European Union. This emerges as a major challenge and simultaneous impediment for the prospective inclusion of West Balkan states into the European Union as this is not merely an issue of economic under performance. As we explain in **Chapter 1** the historical background and the political content still matters a great deal.

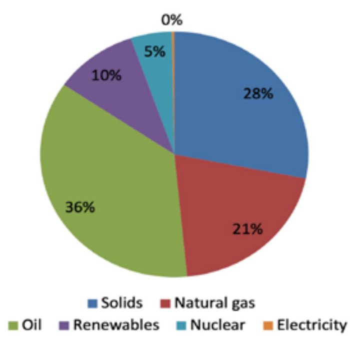
Although the economies of the SEE region appear widely divergent in terms of structure and level of development, they share a number of challenges, which appear to be common to all. Among these, the global economic and financial crisis as well as the impact of the coronavirus pandemic have deeply affected the region collectively and each country individually. **Chapter 2** highlights the economic development challenges of the region and also examines the key economic problems facing the various countries. The present "Outlook" takes the view that, in the post-crisis period in terms of economic and financial prosperity and COVID-19 implications, only states whose governments possess the political determination to cease managing the economy through outdated state control mechanisms will eventually thrive. This is especially relevant to the energy sector which forms a key part of the economies of most countries in SE Europe and which, as it is clearly demonstrated in the present study, is in the process of rapid transition towards decarbonisation.

Today, energy policy formulation and decision making in the SE European region is facing tremendous challenges for a number of reasons (see **Chapter 3**), but primarily related to geography and security considerations, to the existence of abundant but largely unexplored indigenous energy resources, to the divergent demographics, to the great inequalities present in the economies of the various countries and last but not least because of the demands, made by the EU, both to member countries and Energy Community Contracting Parties, for decarbonisation commitments.

In the group of 15 countries examined in the current "Outlook", seven are full members of the European Union and hence bound by means of current treaties and EU Directives to well-defined energy and environment related policies and specific targets, six countries in the Western Balkans are Contracting Parties of the Energy Community and have hence embarked on the road of fully adapting their energy legislation to the Energy Acquis, and finally Turkey and Israel, which have already achieved significant progress in adapting their legislation and market operation to EU requirements, in line with their Association Agreement with the EU.

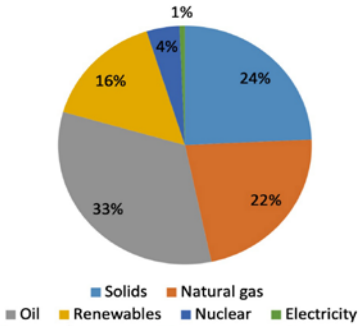
Looking at the broad map of SE Europe, it is useful to examine the big picture and get acquainted with the key issues which confront the region's energy sector (see **Chapter 4**). These include the **glacial change of the regional energy mix** between 2000 and 2019, as shown in Figures 1 and 2, which in spite of the huge rise of renewables and large contribution of gas remains bound to high solid fuel consumption and sizable oil imports. In addition, there is less use of solid fuels, but the retreat is not as big as anticipated so as to advance EU's decarbonisation agenda. Therefore, there is a major policy challenge, which the governments of the countries concerned and the EC, sooner rather than later, will have to address.

Figure 1 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2000 (Total=222.7 Mtoe)**



Sources: Eurostat, IENE

Figure 2 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2019 (Total=300.6 Mtoe)**



Sources: Eurostat, IENE

Chapter 5, which is the largest one of the study, not only explains how the aforementioned key energy issues translate into policy imperatives at national level, but also offers a scholastically detailed presentation of the energy system and energy resources of each of the 15 SEE countries. The Chapter contains "Energy Profiles" for each country where a concise presentation of each country's basic political and economic data as well as the basic policymaking mechanisms in the energy sector are included. Each country's "Energy Profile" also analyzes the basic trends of the country's energy supply and demand. Following that, the country's energy policy is presented on a sector-by-sector basis starting with oil, natural gas, solid fuels, electricity, renewables, energy efficiency and combined heat and power. The Country Energy Profiles also include comprehensive data on energy imports and exports and on basic energy infrastructure.

There is also a group of countries, which are termed as peripheral countries, with which the SEE region maintains close economic and trade relations including energy.

These countries (i.e. Azerbaijan, Austria, Moldova, Ukraine, Italy, Slovakia, Syria, Lebanon and Egypt), presented in **Chapter 6**, are important to the present "Outlook" study as they are associated, in terms of direct energy flows but also trade links, with the region. Each of these countries, for different reasons each, is important as they influence energy related developments and issues in the various countries of the region.

The legal framework for the operation of the energy markets in all countries of SE Europe is described in detail in **Chapter 7**, which also contains ample references to latest legislation per energy source. This is an exhaustive Chapter in the sense that the energy legal background is presented in the same detail for all countries (Bosnia and Herzegovina, Hungary, Israel excluded).

Apart from presenting the current energy situation in SE Europe on a country-by-country basis, there is an analysis per energy source for the entire region. **Chapter 8** provides a comprehensive review of the hydrocarbon exploration and production in SE Europe, as both have been undoubtedly affected due to the coronavirus pandemic.

Chapter 9 covers the oil and gas sector, including oil and gas midstream and downstream (i.e. transportation, storage, refining and retail market activities in the various countries) as well as a separate subsector with a specific reference to gas market, focusing on latest gas market developments and gas demand and supply situation in SE Europe, among others.

Special reference is also made to LNG because of its growing importance for the secure operation of various countries' gas networks and because of its potentially crucial role in market development and competition. In this context, all ongoing or planned gas interconnection projects are examined together with the major cross-country gas pipelines currently under construction or in a development phase. In view of several new projects under development in the region, a redefinition of the Southern Gas Corridor is presented in this Chapter by mapping all new potential gas supply sources and routes.

Therefore, the concept of an **Expanded South Corridor** is introduced and defined as such, to include all major gas trunk pipelines, LNG regasification terminals and underground gas storage facilities, which will ensure that gas if fed into the system with some of them being re-directed towards the main European gas markets.

Finally, this Expanded South Corridor, with its multiple gas entry points and linked underground gas storage and LNG facilities, will provide the necessary background for the operation of regional gas trading hub(s). As a matter of fact, a discussion is made on the possibility of establishing such regional gas trading hubs very much in line with similar gas hubs currently operating in various European countries.

Currently, the electricity sector in SE Europe, as analysed in **Chapter 10**, faces several significant challenges that mainly derive from the ongoing process of market transformation but also the current economic climate, which is the basic driver behind demand. The industry structure, in terms of ownership and regulation framework, being under consideration for a long time, is currently changing in many countries facilitating market competition. The role of the state is reconsidered and the level of privatization and liberalization of electricity markets shapes the business environment in each country, creating new opportunities for market players, especially in the power generation and retail sector.

The presence of new market entities (both old and newly established), like power producers, transmission/distribution system operators and retail suppliers, in each country illustrates the magnitude of changes that the gradual introduction of competition has brought about.

In this context, the main challenges include: **(a)** reform efforts for improving the power market model in line with EU Directives, **(b)** the continuing dominance in many countries' electricity markets of the present incumbent, **(c)** vulnerability to supply disruptions, **(d)** lack of diversification of power generation sources and **(e)** the observed low rate of switching supplier, which involves only eligible consumers who can exercise their right to switch supplier (mainly because of inertia as well as customers' poor awareness and mistrust of new incomers). Factors that have led, in many cases, to a power sector unable to be financially self-sustained, because of the high level of distribution losses, poor collection practices, high rates of illegal electricity usage and tariffs that do not reflect the cost structure.

Ever since the start of the process for developing the internal market in electricity by the European Community and then the EU, the energy sector and more particularly the electricity sector has monopolized EC's attention. It has taken more than 25 years of persistent efforts and countless disagreements and legal cases with incumbent electricity authorities for the European Commission to manage the transition from a state-controlled electricity sector to an open and market-oriented system where competition between different producers, suppliers and distributors forms the basis of operation. In SE Europe, this liberalization process was frought with difficulties and numerous non-technical obstacles, as the incumbent companies in almost all countries solidly resisted any change on the grounds of losing control of the market and hence weakening of their bureaucratic hold.

The situation between EU Member States and Turkey and Israel looks very different with certain countries having managed to complete what appeared to be an anomalous transition period. For instance, in the case of Turkey, the achieved progress in the unbundling of electricity market operation and competition in the retail area has been exceptional and it has now entered into a critical stage with the market opening up much faster than anticipated.

In the case of the Western Balkans, the intervention of the Energy Community through the Contracting Parties has facilitated, on several occasions, the overall transition process to the European Acquis. Hence, some solid steps have been made towards electricity market competition.

Moreover, SE Europe as a whole presents a huge potential for the exploitation of Renewable Energy Sources (RES). Today, although RES penetration is limited in SE Europe, the potential for the utilization of all different forms of RES in the region is quite considerable, as it is clearly described in **Chapter 11**, which covers all different aspects of RES applications, including solar thermal, solar photovoltaic, wind, hydroelectric (both large hydro and small hydro stations), biomass and geothermal. Some countries, such as Greece, Turkey and Cyprus, are very advanced by international standards in solar water heating with millions of installations in place, but less so in electricity generation from solar energy. Indeed photovoltaics are slowly but steadily making their entry into local markets with Greece, Bulgaria, Romania and Turkey in the forefront.

Wind applications are also on the rise with Greece, Turkey, Romania and Bulgaria showing most activity. Hydroelectricity is a common denominator in RES development with almost all countries showing strong interest, especially those that are already using hydro to cover a substantial part of their electricity needs (i.e. Albania, and the rest of the Western Balkan countries, but also Greece and Turkey).

Energy efficiency and relevant application areas in SE Europe are discussed in **Chapter 12**, analyzing the energy efficiency trends of the near past in industrial, household and transport sectors. Cogeneration of Heat and Power (CHP) in SE Europe, which is also analysed in Chapter 12, can be described by its diversity. There are countries, such as Romania, Bulgaria and Slovenia, where CHP plays a serious role in their energy policy during the past period under planned economic models but also today, and there are countries, such as Cyprus, where the role of CHP in their energy mix is insignificant or minimal.

One innovation of the present "SEE Energy Outlook" study is the incorporation of a separate Chapter concerning energy technologies perspectives in the wider region. Energy technology is an engineering science whose main purpose is the efficient, safe, environmentally friendly and economically viable extraction, conversion, transportation, storage and use of energy, preventing at the same time side effects on humans, nature and the environment. After the Second World War, huge progress has been achieved in developing the energy technologies used globally, while continuous technological progress has resulted in numerous improvements and higher efficiencies as well as the introduction of new low-carbon technologies.

The aim of **Chapter 13** is to review the main energy technologies already in use in SE Europe, but also identify others suitable for application in the region. Technologies, such as more efficient batteries for the faster deployment in electric vehicles' as well as the introduction of hydrogen, biomethane and CCUS are only some of them.

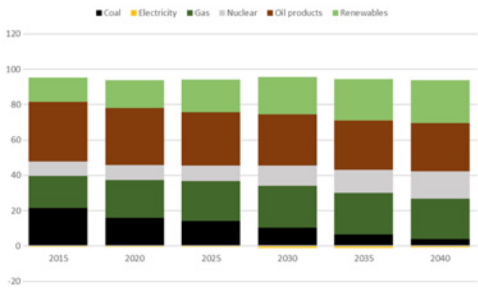
Furthermore, a clearer view of the region's energy profile can be derived by forecasting energy demand and supply over the next 20 years, within the constraints of stated assumptions (see **Chapter 14**). This in turn helps considerably the formulation of desired policies not just on energy but also over a broader spectrum involving vital economic and social issues.

The most recently available studies and the official country submissions of strategic documents (such as the Integrated National Energy and Climate Plans for the EU Member States of SE Europe) were used in order to collect and analyse these projections. The purpose is to present the evolution of the national energy systems corresponding to a "where we are heading" storyline, providing a simple but comprehensive picture of the energy and greenhouse gas (GHG) emissions dynamics under the "current policy" efforts until 2040.

In order to study energy demand and supply patterns, a scenario approach was adopted and presented in **Chapter 15**, whereby certain assumptions have been formulated concerning basic parameters, which are likely to govern future energy demand and supply. These parameters include primarily economic, demographic and energy price information. In the present "Outlook" study, only one such scenario was selected for elaboration, namely the "Baseline" scenario. Looking at the projection of the gross inland consumption in the EU member states of the SEE region in Figure 3, the overall tendency shows a stabilisation and even a small reduction in the time horizon to 2040.

The decrease of the use of coal is evident, reaching a minimum level by 2040, while oil products lose part of their share in the gross inland consumption. The winners to this change are RES and nuclear energy.

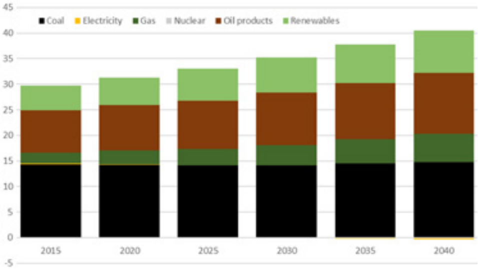
Figure 3 **Gross Inland Consumption in SEE EU Member States, 2015-2040**



Source: IENE

Similarly, the projection of gross inland consumption in the six Western Balkan countries in Figure 4 presents a rather different story from that of the EU member states in the region. Following the expected growth of GDP, gross inland consumption is projected to increase by almost 40% between 2015 and 2040, with the amount of coal being held almost constant, close to 15 Mtoe. Natural gas is the emerging fuel with a constant gradual increase, connected with the pipeline and grid expansion projects in the East and Western Balkans region. Crude oil and oil products will increase by 45% reaching 12 Mtoe in 2040, and renewable energy will rise substantially (by 70%) to 8.3 Mtoe in 2040, but still covering only 20% of the total gross inland consumption of the group of countries.

Figure 4 **Gross Inland Consumption in the Six Western Balkan Countries, 2015-2040**



Source: IENE

The investment and business potential of the region is analysed and discussed in the final section of the study, in **Chapter 15**. A detailed analysis has been undertaken in two directions **(a)** country-related investments and **(b)** cross-border energy project related investments. Country investments are reported using a standardized information format with primary information derived directly from sources in each country, while cross-border project information has been compiled using both published and company sources.

Investment prospects in the broader SEE region for energy related basic infrastructure and energy projects across the board (i.e. electricity, natural gas, RES, thermal power plants, oil and gas exploration, energy efficiency) look positive over the next decade. There appears to be significant improvement in anticipated and planned projects and related investment from now on until 2030. Compared to projections made in 2017 for the period 2016-2025, total estimated energy related investment in the region is much higher and amounts to €483.7 billion. Corresponding investments for the original 13-country group (as they appear in the 2017 Outlook) are slated at €387 billion, which is 41.8% higher compared to the 2017 estimates. This is a vast improvement compared to 5 years ago and clearly shows the substantially increased interest and appetite for energy investments in SE Europe.

Another innovation of the present "Outlook" is the special focus on issues of Environmental, Social and Corporate Governance (ESG).

A growing number of large institutional investors today are incorporating ESG metrics into their capital allocation and stewardship criteria. This shift toward sustainable finance, which has evolved beyond socially responsible investing to include asset management and ownership, has profound implications for investors and companies alike, also for the case of SE Europe.

1

Introduction

Introduction

1.1 Background

The SEEEO is a comprehensive study, which deals with the current energy situation in the SE European region but is also concerned with its "Outlook" from now until 2040. This study is a follow up of similar ''Outlook'' studies published by IENE in 2011 and 2017 (1)(2). The present study covers all 14 countries of the region plus Israel. These countries include: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Slovenia, Cyprus, North Macedonia, Greece, Hungary, Kosovo, Montenegro, Romania, Serbia, Turkey and Israel. Although strictly not part of SE Europe, Israel, located in the East Mediterranean, is developing increasingly close energy ties with the broader region and hence, it was decided to include it in the current energy assessment. The study also provides essential information on key energy projects in certain important peripheral countries such as Lebanon, Ukraine, Moldova, and Italy.

The energy sector constitutes a major economic activity for most countries in SE Europe with a significant contribution to infrastructure investment and market activity. Even more important is the geopolitical role often associated with energy issues as they normally involve bilateral or even trilateral cooperation. A number of major cross-border energy projects are currently under development in the region, including gas pipelines, electricity interconnections, renewable energy applications (e.g. wind farms, photovoltaic plants, geothermal plants, biomass units, etc.) and large-scale energy efficiency interventions, especially in the building sector.

As we have already pointed out in the previous Outlook studies, SE Europe's geopolitical position is unique as it can be viewed as an energy bridge between eastern supplies and western consumers. Furthermore, the region, especially the Black Sea area and the Eastern Mediterranean, can become a major energy producer with sizable export potential. In this respect, SEE's diplomatic, strategic and economic importance, which also arises from extended electricity and gas interconnections, is carefully documented and analyzed. The study also covers latest developments in key energy areas such as refineries, nuclear power, renewables, energy efficiency, cogeneration and of course electricity and gas markets.

The region of SE Europe is characterized by distinctly different (in terms of structure and operation) and frequently segregated, energy "markets" in various stages of development.

In this sense, the present Outlook undertakes a review of the energy sector, including current and planned policies of individual countries, by focusing on key policy challenges that need to be addressed over the next 5-10 years. The study further attempts to discuss these policy challenges at a regional level and proposes necessary initiatives both as part of the transition process envisaged within the Energy Community[1] *(i.e. electricity and natural gas markets)*, which covers the Western Balkans (3) but also agreed energy policy targets in the case of EU member countries (Greece, Cyprus, Bulgaria, Romania, Croatia, Slovenia, Hungary) and associated ones (i.e. Turkey). In this context, regional gas pipeline projects, electricity interconnections, energy market liberalization issues as well as environmental considerations and the ensuing energy transition are discussed at length.

The sectorial analysis focuses on the region's economies, on its key energy and environmental issues, such as decarbonization, and on the existing legal framework on energy. Furthermore, a detailed examination is undertaken on the following key sectors: oil (upstream, midstream, downstream), natural gas, electricity, renewables, energy efficiency and co-generation, environmental issues, associated technologies and investments. A major part of the study concerns the individual countries of the region and contains a comprehensive energy profile of each one of them. A number of energy maps have also been created, along with comparative data tables and economic analyses.

Given the current state of affairs in SE Europe and the constant flux which characterizes most energy markets and the fact that certain major transnational projects, such as gas pipelines, FSRU-LNG plants and electricity grid connections, have suffered serious drawbacks as a reset of Covid-19 complications, with final investment decisions being constantly postponed, and which are impacting investment in the energy sector as a whole, the study provides some useful insight on background developments, at both government and corporate level. In this context, planned and anticipated investments per country and per sector, together with information on available funding mechanisms, are presented in detail in the final chapter of the study (Chapter 15). The size of this regional market is not insignificant. According to the 'Outlook' findings, the total anticipated energy investments by 2030 for the 15-country group are expected to exceed €430 billion.

1.2 The SE European Region Defined

One of the main aims of the study is to bring together the currently available knowledge on energy developments in the region, including information on energy demand and consumption, an assessment of major energy projects and pursued energy policies as well as trends, estimates and projections of energy demand, supply and investments.

Overall, the scope of the study is to present a critical assessment of the current status of the energy markets at large and at the same time provide an insight on their future developments towards the energy transition.

In addition, the study presents the economic and political background of SE Europe and includes analyses on the dynamics of the regional integration process and the impact of EU expansion on economic development and energy markets. Another important part of the study deals with the energy interconnections across SE Europe, while it analyses the oil, gas and electricity markets and at the same time provides in-depth information on major energy projects in the region (i.e. gas pipelines, electricity grids, nuclear plants, refineries, wind farms, etc.). The study also reports on major developments in the energy market liberalization process as well as on the environmental and energy aspects considerations in SE Europe. Finally, the study besides an analysis and projections of the current and future investment potential identifies business opportunities in the broad energy sector of the region.

A considerable part of the analysis presented in the current "Outlook" report is country related and hence, the need to define carefully and understand the geography of the region is paramount. In order to facilitate our approach, we consider the broader region as consisting of four main blocks, as follows: (a) West Balkans, (b) EU member countries - which include the Eastern Balkans (Romania, Bulgaria, Greece, Hungary) and the north of West Balkans (Croatia, Slovenia), (c) Turkey and (d) the East Mediterranean (Cyprus, Israel).

Inevitably a large part of the aforementioned discussion focuses on the need to upgrade and further expand energy infrastructure, together with priorities on market reforms mainly in electricity and gas. We should nevertheless point out that the Soviet era's economic legacy is still felt in certain countries as considerable part of the region, comprising more than half of its land mass, was until 30 years ago governed by the COMECON framework.

In this sense, the still incomplete process of moving from a centralized type of economy to fully open economy, with all the implications that such a move entails for the energy sector, still presents considerable challenges on economic activity and government policies in some countries in SE Europe. This becomes most visible in the case of Western Balkans, which as it is being pointed out by an IEA survey[2], much of the energy infrastructure was damaged during the conflicts related to the break-up of the Socialist Federal Republic (SFR) of Yugoslavia in the 1990s.

The rebuilding process has been long and difficult and still goes on, alas, amongst continuing distrust within certain communities. Consequently, in these countries energy reforms were initiated at a later stage than other European economies in transition. For instance, electricity systems in some parts of the region still remain extremely fragile and as a result low system reliability and low efficiency impede economic recovery. However, reliable and affordable energy supply is crucial for economic development and social welfare, not only across Western Balkans but for the whole SE European region.

Map 1.1 **The 4 Country blocks**

Source: IENE

Map 1.2 **The SE European Area Defined***

*This comprise the 15-country group being examined in this Outlook study.
Source: IENE

[2] IEA (2018), "Energy in the Western Balkans – The Path to Reform and Reconstruction", https://iea.blob.core.windows.net/assets/6f3556ba-55bc-4d5b-927c-2d027fd2ebfb/Balkans2008.pdf

The present study breaks new ground since with the inclusion of Israel it broadens its East Mediterranean coverage which now comprises Greece, Turkey, Cyprus and Israel. Turkey is an OECD member country, the economy of which, because of its size and dynamism, affects to a large extent financial, trade and energy flows to the rest of SE Europe. The same though cannot be said for Moldova or Ukraine which although energy linked to SE Europe, through electricity and gas interconnections, their economies, far from being integrated, are lagging behind those of other countries in the SE European region. For this reason, these two countries have not been considered in the present Outlook although some basic information is provided on them in Chapter 6 which deals with the peripheral countries.

1.3 The Political Context

Historical Background

Whichever way you look at it, SE Europe is an area which covers a huge geographical expanse of immense cultural diversity and a mosaic of political beliefs where history is still in the making in some areas. An outside observer, who may be tempted to examine the historical background and the relations between the various countries and their people, will soon realise that history is still throwing a heavy shadow on today's world. If one was to start a hypothetical journey transversing the region from the very northwest in Slovenia, then move south to Croatia and then set out to visit the Western Balkans - Montenegro, Albania, North Macedonia, Kosovo, Serbia, Bosnia and Herzegovina - then move further south to Greece and from there northeast to Bulgaria, Romania and Moldova, he or she may soon come across the common historical legacy of this truly wild and intriguing region. A legacy which is non other than the Ottoman Empire where for many years this furthermost area of Europe occupied.

As Mark Mazower very appropriately observes in his acclaimed study on the Balkans (4), successor states – Greece, Bulgaria, Serbia, Romania and Montenegro – had emerged during the nineteenth century as contenders to carve up what remained. Between 1878 and 1908, diplomatic conferences whittled away Ottoman territory, and subjected what remained to Great Power oversight. By the time of the outbreak of the First Balkan War in 1912 which ended Ottoman rule in Europe (outside the immediate hinterland of Constantinople) – the word 'Balkan' had become common currency and was used to describe a rather backward and rich in strife region. The name generally given to that segment is "the Balkan Peninsula" or simply "the Balkans". From the very start, the Balkans was more than a geographical concept. The term, unlike its predecessors, was loaded with negative connotations – of violence, savagery and primitivism – to an extent for which it is hard to find a parallel. "Why 'savage Europe'?" asked the journalist Harry de Windt in his 1907 book of the same name. "Because as the term accurately describes the wild and lawless countries between the Adriatic and Black Seas" (5).

The region's history came to be dominated by revolt and revenge stretching back almost a century and climaxing after 1900 in the terrorist bombings of the VMRO, the Serbian regicide of 1903 and the widespread massacres of 1912-1913 and the ensuing First World War, carried out by all sides. It was no wonder that Europe came to associate the region with violence and bloodshed. A decade of intermittent upheaval ended in 1922 with the decimation of the Greek population in Asia Minor, and the forced population exchange of nearly two million refugees between Greece and Turkey.

If this was not enough the Second World War destroyed the tentative stability of the inter-war period. What re-emerged during the post-war period was Soviet domination, which was contested only by Tito's Yugoslavia (6) and to a lesser extend Albania's Hoja regime after his rapprochement with China in the early 1960s (7). As Mazower puts it, "The Balkans disappeared from Western consciousness during the Cold War, the Iron Curtain ran through southeastern Europe, separating Greece from its Communist neighbors.

Albania became virtually impenetrable. Tito's Yugoslavia was idolized by American policymakers and by the New Left in Europe; the language of international non alignment and of workers' self-management at home fell on receptive ears abroad. Nicolae Ceausescu's rule in Romania was known more for its pronounced anti-Sovietism in foreign policy than for its extreme repression of its own population. In general, Greece became a marginal part of 'the West', while the other Balkan states formed the least studied part of Communist Eastern Europe. Mass tourism brought millions to the region's beaches and ski slopes, and turned peasant culture into after-dinner entertainment. The picturesque replaced the violent, and the worst problems most tourists anticipated were poor roads and unfamiliar toilets" (8).

The collapse of the communist regimes and one-party states in the whole of SE Europe (apart from Greece and Turkey which never came under the iron curtain) in 1989/1990 meant the reshaping of the political order and most importantly resulted in deep changes in the economy. It also meant the end of the old idea of socioeconomic transformation through the domestic policies of the individual state. Accession to the European Union became the single most important political goal for all countries in the region as it meant political stability and market liberalisation with dismantling of tariffs and protected state industries. But it also meant exposure to global competition. Hence, as Mazower points out, "the traditional Balkan nation state is no longer challenged by the old empires; it is not even challenged by the rivalry and hostility of neighbours; it's main threat comes now from the international economy" (9).

An Unstable Region

Almost 20 years after the ending of the Yugoslav wars and 26 years after the signing of the Dayton Accords, which ended the war in Bosnia and Herzegovina, memories in the region are still vivid. The wars were a series of separate but related ethnic conflicts, wars of independence, and insurgencies fought in the former Yugoslavia territory from 1991 to 2001, leading to the breakup of the Yugoslav federation in 1992. Its constituent republics declared independence due to unresolved tensions between ethnic minorities in the new countries, which fueled the wars in the first place.

Often described as Europe's deadliest conflicts since World War II, the Yugoslav Wars were a series of separate but related ethnic conflicts, wars of independence, and insurgencies fought in the former Yugoslavia from 1991 to 2001, leading up to and resulting from the breakup of the Yugoslav federation in 1992. Its constituent republics declared independence due to unresolved tensions between ethnic minorities in the new countries, which fueled the wars. Most of the wars ended through peace accords, the better known of which is the Dayton Accord of December 1995, involving full international recognition of new states, but with a massive human cost and economic damage to the region. Initially the Yugoslav People's Army (JNA) sought to preserve the unity of the whole of Yugoslavia by crushing the secessionist governments, but it increasingly came under the influence of the Serbian government of Slobodan Milošević, which evoked Serbian nationalism to replace the weakening communist system. As a result, the JNA began to lose Slovenes, Croats, Kosovar Albanians, Bosniaks, and Macedonians, and effectively became a Serb army (10).

According to a 1994 United Nations report, the Serb side did not aim to restore Yugoslavia, but to create a "Greater Serbia" from parts of Croatia and Bosnia. Other irredentist movements have also been brought into connection with the wars, such as "Greater Albania" (from Kosovo, though it was abandoned following international diplomacy) and "Greater Croatia" (from parts of Herzegovina, until 1994 when the Washington Agreement ended it) (11).

But apart from the still fresh political and emotional fallout from the Yugoslav wars – most visible in the friction still present today between Serbia, Kosovo and between ethnic communities in Bosnia and Herzegovina - we still have strife conditions and live conflicts in the broader region especially as we move east. The current political and military tensions between Ukraine and Russia, with the involvement of the USA and the EU, is a case in point and is most worrying in terms of regional stability, while Turkey's open support to Azerbaijan in its dispute with Armenia, over the Nagorno-Karabakh issue, has resulted in renewed warfare (summer 2021) adding a further point of friction. In addition, we have Ankara's repeated challenging of Cyprus and Greece over seabed rights and their Economic Exclusion Zones (EEZ) in the Aegean and the East Mediterranean which has given rise to renewed tensions and to which we refer to in Chapter 4.

Current Issues

Reference to the Yugoslav Wars and their outcome in terms of human loss and the new political reality which came about with the emergence of seven separate states (Slovenia, Croatia, Bosnia and Herzegovina, Serbia, Montenegro, North Macedonia and Kosovo) and the open issues related to geographical borders and EEZ, is both useful and necessary if we are to understand the current political milieu and the new challenges facing the region. Although the fear of an open military conflict between neighbouring countries in the region still hangs on the air, it seems that the most important challenges facing governments across SEE are related more to economic and energy issues, which of late, as prices have been rising throughout 2021, have come to dominate the economic agenda.

In this context, one has to read through the plans and aspirations expressed by the new states which appear to originate more from a deep sense political insecurity which they inherited following the breakup of rump Yugoslavia, rather than their urge for fast and uncompromising economic development. Hence, the common desire to join the European Union - already materialised in the case of Slovenia and Croatia - which they see as a bastion of stability, lawfulness and economic anchor.

Consequently, any delays or impediments in the accession process of West Balkans give rise to protests and friction usually addressed to neighbours but also to EU's leadership. The case of Serbia is most relevant in this debate since the country appears to be the most advanced in its negotiations as it is officially a candidate country and is already in negotiations with Brussels.

Lately, Serbia has taken a step toward in its goal of joining the EU by opening talks on four policy areas, but European officials warn Belgrade that progress in the process still depends on continued reforms and normalizing relations with Kosovo. To be eligible to join the 27-country EU, applicant states must bring their laws and regulations into line with the bloc's standards through negotiations in 35 policy areas, or chapters, including finance, agriculture, transport, energy, social, and justice policy.

The EU established a regional approach to the Western Balkans in 1997, with political and economic conditionality criteria for the development of bilateral relations. On 6 February 2018, the European Commission published its expansion plan to cover up to six Western Balkan countries: Albania, Bosnia & Herzegovina, Kosovo, Montenegro, North Macedonia, and Serbia. The plan envisages that all six applicants could achieve accession as members of the European Union after 2025. The most advanced of the above candidate countries for accession to the EU is Serbia.

On December 14 2021, Serbia was allowed to open talks on climate change and environment, energy, transport policy, and trans-European infrastructure networks - the first time the Balkan country has opened four chapters at once. Belgrade has now opened 22 negotiating chapters since its membership talks began in 2014. "Serbia is taking yet another very important step forward joining the European Union," EU Enlargement Negotiations Commissioner Oliver Varhelyi said following the intergovernmental conference with Serbia in Brussels.

Gasper Dovzan, state secretary at the Slovenian Foreign Ministry, whose country is (second half of 2021) holding the presidency of the EU Council, said that the Serbian government "prioritized EU-related reforms and delivered on a number of important commitments, in particular on taxation and energy." But "further efforts are needed," Dovzan said, citing judiciary independence, media freedom, and the fight against corruption and organized crime. "Serbia's progress on the rule of law and the normalization of relations with Kosovo remains essential and will continue to determine the overall pace of the negotiations," he added (12). Kosovo declared independence from Serbia in 2008 after a 1998-99 conflict between ethnic Albanian separatists and Serbian forces. The war ended after a 78-day NATO air campaign drove Serbian troops out, and a peacekeeping force moved in. Kosovo's independence has been recognized by more than 100 countries including the United States and all but five of the EU member states. But Serbia still considers the territory a southern province and is supported by Russia and China. EU-mediated talks between Pristina and Belgrade to settle their differences have stalled.

Next in line for opening accession talks with the EU is **North Macedonia**. Despite the hopes raised by France's support for opening membership talks with Albania and North Macedonia, the European Union once again delayed matters. "The Council looks forward to the holding of the first intergovernmental conference [with Albania and North Macedonia] as soon as possible," stated the General Affairs Council's conclusions on December 14. The main reason for the delay, for a second year in a row, was Bulgaria's block on North Macedonia's EU path over an unresolved history and identity dispute. Sofia insists on Skopje accepting a de facto Bulgarian identity that centres around the claim that the North Macedonian identity and language are of Bulgarian origin.

The EU has in recent years tied Albanian talks to those of North Macedonia, so both countries are delayed.

North Macedonia's government narrowly avoided collapse on November 11 2021, partly on account of the EU membership issue. The ruling social democrats (SDSM) avoided a parliamentary confidence vote they would have lost, when a member of the ruling coalition went into hiding. The MP, who belonged to the ethnic Albanian party Besa, was expected to vote against the government and join the opposition. The opposition VMRO-DPMNE conservatives called for the confidence vote after seizing 42 of the country's 58 town halls in nationwide local elections on October 31, 2021. Prime minister Zoran Zaev initially said he had lost the people's confidence and would resign, but he later postponed that resignation indefinitely (finally he was resigned in December 2021). North Macedonians are disillusioned by the lack of progress towards EU membership.

The Zaev government had assured them that EU membership would follow a 2018 agreement that changed the country's name following objections by EU member Greece to 'Republic of Macedonia'. The 2018 deal did allow North Macedonia to enter NATO immediately (13). The new government in Sofia (December 2021) has signaled that it intends to normalize relations and lift some its objections (14).

When it comes to the rest of the West Balkan countries the prospect of opening accession talks with Brussels looks increasingly remote given a number of still unresolved problems ranging from territorial issues, to rule of law issues and economic and environmental issues. **Kosovo's** case seems the more acute since in order to ensure stability at the territory and neutral rule of law enforcement, the EU is operating in Kosovo under the umbrella of the United Nations Interim Administration Mission in Kosovo (UNMIK), deploying police and civilian resources under the European Union Rule of Law Mission (EULEX). The Stabilisation and Association Agreement (SAA) between the EU and Kosovo was signed on 26 February 2016 and went into force on 1 April 2016.

Another difficult case when it comes to EU accession is **Bosnia and Herzegovina**. Although the country formally applied for EU membership in February 2016, following years of constitutional reforms and engagements arising from the Dayton Peace Agreement, serious unresolved problems related to the functioning of government remain. The official EU position is that it remains a potential candidate country until it can successfully answer all of the questions on the European Commission's questionnaire sheet as well as "ensure the functioning of the Stabilisation and Association Parliamentary Committee and develop a national programme for the adoption of the EU acquis". Many observers estimate that Bosnia and Herzegovina is at the bottom in terms of EU integration among the Western Balkans states seeking EU membership.

Like the other countries in the West Balkans, **Albania's** drive to join the EU remains strong and the country has indeed managed to overcome several obstacles in its accession path. Successive governments in Tirana see their country's future firmly in the hold of the EU with which they have a growing trade relationship. Following recognition as "a potential candidate country in 2000", Albania followed in the steps of other candidate countries and has been extensively engaged with EU institutions and joined NATO in 2009. The full adaptation of European Acquis in Albania's energy market regulation is a cornerstone of Tirana's energy policy while it seeks full participation in EU energy market mechanisms such as the Target Model and the operation of an Energy Exchange.

On 23 June 2014, under the Greek EU Presidency, the Council of the European Union agreed to grant Albania candidate status, which was endorsed by the European Council a few days later. Albania's EU accession is bundled with North Macedonia's EU accession. Albania is given certain pre-conditions for starting the accession negotiations, such as passing reforms in the justice system, a new electoral law, opening trials for corrupt judges and the respect of human rights for its Greek minority. In May 2019, European Commissioner Johannes Hahn reiterated this recommendation. Eventually, on 25 March 2020, the Council of the European Union decided to open accession negotiations, which was endorsed by the European Council the following day (15). Montenegro seems to be one of the most likely candidates in the region for EU accession in this decade. The negotiations with Montenegro started in 2012 and as of 2020 32 of 35 chapters had been opened for negotiation. Thus, most of the chapters have already been opened and some have been provisionally closed. In March 2021, the chief negotiator for Montenegro announced that the country aims to fulfil all requirements by 2025. The European Council outlined some of the main areas in need of reform in a 2019 report. These areas are the rule of law, corruption, public administration reform and freedom of expression.

Turkey

EU-Turkey relations have been tense since late 2000s, as Turkey's accession process with the EU began to slow down and political and economic reforms in the country came to a halt. The EU and Turkey have divergent views over several issues, e.g. the eastern Mediterranean, the Cyprus issue, regional conflicts, such as Libya and Syria, and democratic standards. For instance, Turkey criticized the EU over stalled accession talks on December 17, 2021, saying that the bloc's policies are "detached from reality" and "based on ideological motives"[3]. The General Affairs Council of the EU expressed a few days earlier its concern over Turkey's democracy, rule of law and fundamental rights, adding that "Turkey's accession negotiations effectively have come to a standstill and no further chapters can be considered for opening or closing". The Turkish Foreign Ministry said in a statement that the decisions adopted by the EU have shown once again that the bloc approaches enlargement within the framework of "membership solidarity, not from a strategic perspective". EU relations apart, Turkey's real goals and aspirations are aimed at regional, if not global, level. President Erdogan's power play involves the projection of Turkish power over a very large geographical area, stretching from North and West Africa to the Gulf region, to Somalia, the Caspian Sea and Pakistan. His vision is not confined to SEE and the Mediterranean but encompasses a much larger sphere of influence. Energy, in all its forms, plays key role in Turkey's expansionary plans, especially as it relies at a very high degree on oil and gas imports. However, this grand vision is not currently supported by a robust economy as the Turkish lira has been on a constant downfall over the last two to three years, having lost 57% of its value since the beginning of 2021.

Apart from the EU, which is Turkey's most important export market and main source of investment, relations are also at a low point with the United States, which reached an all-time low. Turkey's dependence on capital inflows means that a sudden change in the risk appetite of investors can have a significant negative impact on macroeconomic indicators.

As an illustration of the problem, in 2018, when US President Trump on Twitter threatened Ankara with sanctions, this led to a sharp depreciation of the lira, after which the economy stagnated.

However, one of the most important issues (if not a top priority) that Turkey has to deal with is its ominous current economic situation. The global financial crisis of 2008 hit the country's economy hard. In the aftermath of the financial crisis, quantitative easing by the major central banks caused a large flow of capital into emerging markets, which Turkey benefited from. This led to a rapid expansion of credit in the country, much of it channeled to the construction and real-estate sectors. The economy continued to grow at high rates, but the low rate of savings - one long-standing vulnerability - did not improve. As a result, the economy remained dependent on capital inflows or "hot" money from abroad, mostly in the form of short-term capital.

This led to an escalation of private debt denominated in the US dollar. When the coronavirus pandemic struck in 2020, Turkey was already suffering from a record depreciation of the lira and a depletion of foreign-exchange reserves to counter this, as well as from double-digit inflation for the previous two years. The pandemic has further deepened the country's economic difficulties. The turmoil has caused a strong downward spiral of the lira and inflation has fluctuated in the double digits, standing at 20% and more. The official unemployment rate exceeded 13% and youth unemployment 25% in 2020[4] .

Turkish president Recep Tayyip Erdogan's defence of recent interest rate cuts and a declaration of an "economic war of independence" has sent the lira plunging and left analysts wondering how much further he is willing to let the currency fall. Erdogan, who has sacked three central bank governors since mid-2019 and is a life-long opponent of high interest rates, has insisted that he will continue on the path of low rates in a quest to stimulate growth and investment, as a recent article by the Financial Times highlights[5].

Figure 1.1 **Turkish Lira in Historic Retreat**

Sources: Refinitiv, Financial Times

The Energy Angle

Over the last twenty years or so, as reconstruction gathered pace in Balkans and as new EU members states (i.e. Slovenia, Croatia, Bulgaria and Romania) were finding

[3] RT (2021), "Turkey blasts EU over stalled accession talks", https://www.rt.com/news/543563-turkey-eu-stalled-accession-talks/
[4] Tastan, K. (2021), "Erdoğan's Gamble with Turkey's Economy", https://www.gmfus.org/news/erdogans-gamble-turkeys-economy
[5] Pitel, L. and Wheatley, J. (2021), "What the lira collapse means for Turkey's economy", https://www.ft.com/content/7c3ec643-0045-4437-9e7f-66e1385af2ce

their bearings within the single market, energy emerged as a key factor and a strong cohesive force capable of forging together disparate interests and in promoting economic activities which simply could not otherwise develop. It is in SE Europe more than anywhere else that one realizes that economic activity cannot advance without abundant and relatively cheap (i.e. affordable) amounts of energy. The repositioning or rebranding of the region (as many neoliberals like to call it) as SE Europe is on the one hand contributing in taking a fresh look in the broader geographical area, and on the other helps define it in economic terms, where energy has emerged as a basic consistent and vital part in the functioning of the economies of the various countries. In addition to its role in economic development, energy provides a much-needed link between the various countries. The re-emerge of SE Europe as a new geopolitical block has also far-reaching implications in terms of social and economic development, especially in view of its closer economic and political ties to the European Union. A major consideration, as we shall see in the chapters which follow, when it comes to studying and analyzing the energy issues involved.

In this context, one should observe that the closer the countries of the SEE area get to the EU, either by membership or association, the less becomes the direct influence that traditional players in the region, such as Russia, Germany and China (read Albania). Also, following the Dayton Accord USA's influence in the region has been strong, especially in Western Balkans. We should remember though that Russian influence is still present in countries like Serbia, Romania, Bulgaria and North Macedonia because of religion, cultural ties and until very recently language.

With all of these countries relying mostly on Russia for their gas import needs (with the exception of Romania which is becoming increasingly self-sufficient thanks to its own gas reserves), the links with Moscow still remain strong. The entry of China in the region, almost 15 years ago, as a major trade and technology partner has been slow and steady.

The crux of Chinese influence is largely focused on energy and infrastructure through the provision of funding for new power stations and electricity grids.,

However, concerns over China's investments in SE Europe are not just limited to its coal drive, against EU stated decarbonization policies, but spring from worries of the financial consequences of overexposure of SE European economies to Chinese investments. As the Economist noted in 2019 (16), there are concerns about the financial consequences of the Belt and Road Initiative (BRI). The most extreme is that the scheme involves what is pithily described as "debt-trap diplomacy". In this view, China is deliberately overloading weak countries with loans; when they buckle, it seizes their assets and influences their politics. Currently, in SE Europe, a number of coal-fired power plants have attracted strong Chinese interest as they already form part of pursued national energy policies by a number of countries, as several EU enlargement countries in the Western Balkans, such as Bosnia and Herzegovina, Serbia and Kosovo, plan to build new lignite-fired power plants.

These coal projects are not compliant with the Paris Agreement's aim of limiting climate change at least to 1.5°C but readily available Chinese money is enabling them to proceed. As the international financial institutions have phased out direct coal financing, most of the plants are slated for loans from the state-owned China Eximbank or other Chinese public banks. Up to 3.5 GW of coal-fired power plants may be built in SE Europe in the current decade with Chinese financial support, based on CEE Bankwatch Network's estimates (17).

Beijing's ambitious plans to play key role in SE Europe as an alternative economic influence, besides the EU, Russia and the USA, have at present been stalled following sharp reaction from Brussels and Washington over the last two years; especially as China's predatory plans in this part of the world have come under increased criticism and investment plans are being carefully scrutinised.

This change of attitude towards Beijing follows the deeper rift and negative environment in economic and trade relations between Washington and Beijing which has come about as Chinese technology firms motives are increasingly being questioned on security grounds by both the US government but also by the UK and the EU. This does not necessarily mean that Beijing's geopolitical ambitions in the region have come to an abrupt end. However, at present China's geopolitical play in SEE is being seriously questioned and remains to be seen if and when Beijing will wish to reestablish a stronger presence (18). The present study is structured in such a way as to provide both a penetrating glance but also an overview of the energy scene in the SE European area. By means of detailed country and sectorial analysis, the region's rich energy resources base is identified and the efforts to tap it are described. Also, the present shortcomings in the structure of the current energy mix are recognized while forecasts are made, supported by modeling, of anticipated energy demand and supply for the various countries but also for the region as a whole. In addition, SE European energy related investment potential and outlook is identified together with the appropriate strategies and policies, which will enable actual investments to be realized while aiming at a more equitable utilization of the region's resources. Another important policy parameter, which comes out strongly in this study, is energy security, which clearly has huge political implications. Indeed, maximizing the utilization of indigenous energy resources, both conventional and alternative ones in parallel with strong interconnections and optimization of energy imports could enhance energy security and help reduce the region's carbon footprint. Chapter 4 provides a detailed analysis on the region's energy security issues.

As the region traditionally has lagged behind main European trends, only to catch up enthusiastically years later, now it seems to be racing ahead of time in an effort to take advantage of a new wave of reforms in the offing. This is most evident in the case of energy where thanks to latest advances in information technology (e.g the internet) and digitalization the region is embracing fast the tenets involved in energy transition aspiring to cleaner forms of energy.

Although energy transition, in the case of EU member countries, has become of late official government policy and clearly embedded in their national energy plans it does not yet enjoy wide acceptance among the population and industry which seem very uncomfortable with rising energy prices. The situation, as we commented earlier in the chapter, is worse in the case of Western Balkans as official government policy on energy by a number of countries considerably diverges from that of the EU. Yet, the fast forward drive towards a future of clean energy and lesser dependence on traditional oil and gas imports may be challenged as a result of yet unresolved border and governance issues going back to centuries' old conflicts and antagonism.

1.4 Focus on Western Balkans

The Dual Transition of the Western Balkans

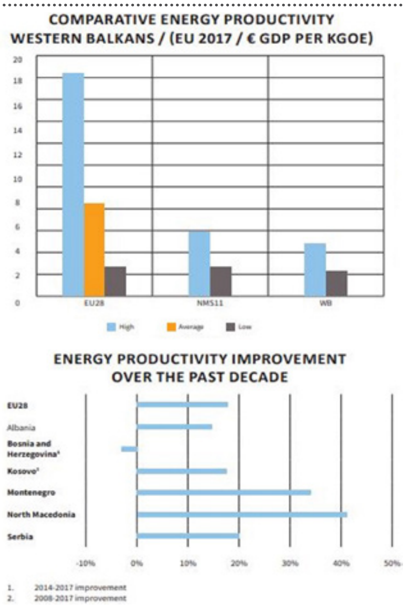
The case of Western Balkans merits special attention since the energy sector faces a unique dual transition, a challenge without any precedent in the industry: transition from centralised state-controlled systems to open and competitive markets, and at the same time transition towards decarbonisation.

Participation in the Energy Community Treaty, which aims at extending the EU internal energy market rules and principles to countries in SE Europe and beyond, provides a clear policy framework but the task remains considerable. As it is pointed out in the recent Western Balkans Investment Framework (WBIF) Clean Energy Factsheet[6], the sector is characterized by limited market mechanisms and private sector's participation, insufficient and aging infrastructure, high reliance on fossil fuels, late adoption of renewables beyond hydropower and residential biomass, limited energy

[6] WBIF (2021), "Clean Energy", https://www.wbif.eu/storage/app/media/Library/FactSheets/Sector%20Factsheets%20 2021/WBIF%20ENE%20Factsheet%20Nov%202021.pdf

efficiency and energy productivity, and high rates of energy poverty despite usually high levels of direct and hidden energy subsidies (mostly targeted towards fossil fuels). Similar to other transition economies, the Western Balkans emerged from the socialist era with low energy productivity. Significant but uneven progress was made over the past 10 years and the gap with transition economies among EU Member States is moderate. However, the highest regional achiever remains at approximately half of the EU average of €8.27/ Kgoe. Montenegro and North Macedonia have improved the most at twice the average EU speed; Kosovo and Serbia have largely matched average EU progress; Albania has somewhat lagged behind; while Bosnia and Herzegovina has not shown improvement over the shorter period for which data is available, the WBIF study [7] supports.

Figures 1.2 & 1.3 **Comparative Energy Productivity in the Western Balkans** *(above)* **and Energy Productivity Improvement over the Past Decade** *(below)*



Source: WBIF

Furthermore, reliance on low-grade lignite in power generation in most countries in the region adversely affects air quality (and acid rain), not only in the region but also in neighbouring countries, with reduced life expectancy and increased health costs as consequences. The region is home to eight of the ten most polluting plants in Europe and the sixteen coal plants located in the Western Balkans perform poorly compared to the 250 coal plants active in the European Union according to a 2016 study[8]. The same study estimated induced annual health damages from coal plants at a minimum of €1.2 billion for the region alone. Problems are particularly acute in North Macedonia or Bosnia and Herzegovina, where Skopje, Tetovo or Tuzla usually rank among the worst cities in Europe for air quality. B&H and North Macedonia's air pollution can be attributed to emissions from the industries, loosely regulated vehicles, the burning of outdoor waste and domestic heating.

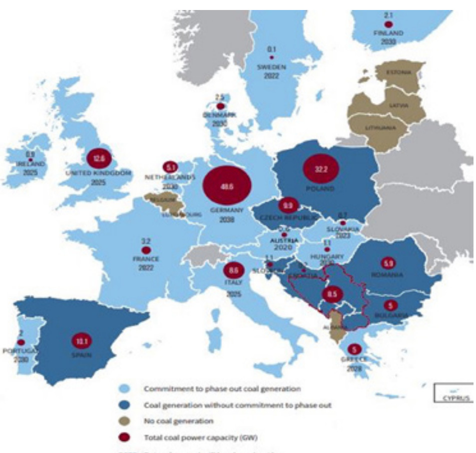
Table 1.1 **Total Emissions of Main Pollutants by Coal Power Plants in the Western Balkans and the EU**

Total emissions of main pollutants by coal power plants in the Western Balkans and the EU			
	SO2 (t/year)	NOx (t/year)	PM 2.5 (t/year)
EU-28*	992,248	795,358	11,946
Western Balkans**	750,893	120,012	20,188

** Only 22 EU countries have coal power plants*
*** Excluding Albania where there is no coal power plant*

Sources: HEAL (2017)

Map 1.3 **Western Balkans Coal-Fired Power Generation, A European Perspective**



[7] WBIF (2019), "Investing in Clean Energy in the Western Balkans", https://wbif.eu/storage/app/media/Library/9.Sectors/1.Energy/EE%20Brochure%20final%20dec%202019.pdf

[8] HEAL (2016), "The Unpaid Health Bill - How Coal Power Plants in the Western Balkans Make us Sick", https://www.env-health.org/IMG/pdf/heal_report_the_unpaid_health_bill_how_coal_power_plants_make_us_sick_final.pdf

Although current energy consumption per capita is approximately half than in the European Union, economic development should lead to an increase in consumption, both through development of manufacturing and through increased consumption in the residential sector as comfort levels rise. Decarbonising the regional energy sector thus emerge as a key challenge to reduce emissions and improve air quality. There is a substantial RES potential to help in the process. For instance, a WBIF study on Sustainable Hydropower in the region[9] identified about 50 projects in the sector (refurbishment/upgrade/greenfield) worth further analysis. In addition, IRENA estimates that capacities of 12.2 GW of wind and 4.4 GW of solar PV could be cost competitive in the region today if the cost of capital was in line with that observed in neighbouring Croatia, Hungary, and Romania. Current total generation capacity in the region is 18.6 GW, including approximately half from coal, as the WBIF (2019) study notes.

However, and unlike most EU countries, certain Western Balkan countries (i.e. Serbia, Kosovo, Bosnia Herzegovina) have not yet committed in phasing out coal but instead plan to add significant new coal power capacity by 2030, in contradiction with commitments under the Energy Community Treaty and increasing regulatory drift from the EU. But their governments (not without reason) insist that only coal, an indigenous resource, can provide energy security and guarantee affordable electricity prices.

Action is needed in the transport sector too where the dominance of road transport and an ageing vehicle fleet are contribution to both emissions and air pollution. For instance, almost 80% of registered cars in Bosnia and Herzegovina are over 15 years old, making the country's car fleet one of the oldest in Europe. Efforts however have been limited beyond investment in Trans European Network rail corridors and bans on importing ageing second hand vehicles.

The picture is brighter for energy efficiency for which significant efforts have been deployed over the past 10 years and spearheaded by the Energy Community, IFIs and donors (Details are presented in Chapter 12 of the Outlook study). However, much remains to be done in particular in the public sector which has been set unchallenging targets for its large building stock or in the residential sector where sustained efforts started only fairly recently.

If the portfolio of projects that have received some EU support over the period is a reliable guide, these efforts have been fruitful. As a rule of thumb, the portfolio shows that €1 million in clean energy investments can be expected to generate primary energy savings in excess of 2,000 MWh and emissions savings in excess of 1,000 tons, while sustaining employment estimated at more than 11.75 person years.

As the same study highlights, "Decarbonisation and energy efficiency are often seen as costs but it is clear that they could become drivers for regional growth through (i) building up on successful energy efficiency efforts in the region which have proven their economic viability; (ii) utilisation of a large untapped renewable energy potential; (iii) addressing the policy challenge and the health costs of a large coal-fired generation sectors and (iv) the induced effect on economies of a more reliable, more competitive and cleaner energy supply as well as of a healthier population".

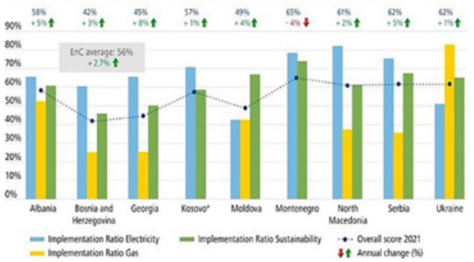
Energy Transition Slows in the Western Balkans

According to the Energy Community Secretariat's Annual Implementation Report for 2021 (19), its contracting parties achieved only modest progress in reforming their energy and climate sectors over the last two years (2020-2021). Montenegro, which still has the best score, was the only country that reversed its gains in 2020, as it is late with the overhauling of the Pljevlja coal plant.

9 WBIF (2017), "Regional Strategy for Sustainable Hydropower in the Western Balkans", https://www.wbif.eu/storage/app/media/Library/10.Projects/1.Hydropower/21%20WBEC-REG-ENE-01-Final-Report-05.12a.pdf

The overall pace of reform within the Energy Community was halved in the past year. The total implementation score increased to 56% from 53%. In the Western Balkans, only Albania and Serbia had growth above the overall average, both gaining five percentage points to 58% and 62%, respectively.

Figure 1.4 **Overview of Implementation Performance by Contracting Parties**

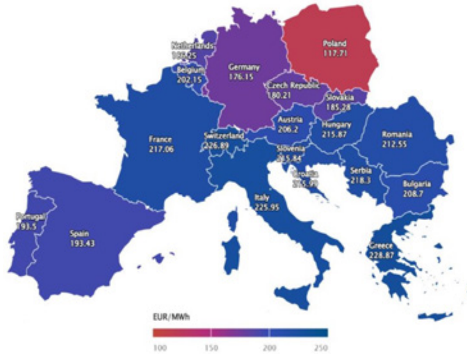


Source: Energy Community Secretariat

The Energy Community report shows that regional power market integration remains one of the biggest challenges. The gap in the implementation of the European legislative package on capacity allocation, balancing and system operation remains high on the priority list. "Without the further integration of their power sectors, the domestic markets, which are all of small scale, with the exception of Ukraine, will remain sub-optimal and unable to facilitate the transition towards a decarbonized and decentralized electricity sector. The region must prepare for the large-scale deployment of variable renewable energy sources," Deputy Director Dirk Buschle said (7). For now, domestic lignite and coal-generated power are again in high demand, Kopač and Buschle warned and asked the contracting parties to stay focused on decarbonization.

According to the report, Serbia (which is not market coupled), recently experienced the highest electricity prices in Europe for several days on its day-ahead market. Furthermore, the report says that small, isolated markets are more prone to price volatility. Although the reverse is not necessarily true as recent experience shows since as fully coupled markets experienced very high prices in November and December 2021 (see Map 1.4).

Map 1.4 **Day-ahead Electricity Prices in Europe (November 2021)**



Source: Energy Live

The contracting parties that have coal in their energy mix are still struggling to comply with the emission ceilings established under their national emission reduction plans (NERPs). Albania doesn't have any coal mines or plants using the fossil fuel. Nevertheless, there was at least some progress in all major areas in the Western Balkan contracting parties, with the exception of gas regulations in Bosnia and Herzegovina. With a share of 21.4% of renewable energy sources in 2019, Serbia was still far from its overall indicative trajectory of 25.6% in 2019, and the target for 2020 was 27%, while reforms in the gas sector are at an early stage.

"Government announcements of possible interventions in their energy sector in response to the crisis could further fuel the energy prices. While interventions are legitimate to the extent they address the impact of the price hike and protect vulnerable customers, they become problematic when such interventions are not proportionate in scope or in time, and when the reforms of energy market governance, having sometimes only recently been aligned with the European Union's, are being called into question," the report reads.

The secretariat acknowledged more support is necessary – a Green Marshall Fund for the Energy Community – to make sure that the transformation is feasible and just. According to the document, the contracting parties have ways to go carbon pricing, "arguably the most effective instrument in the Green Deal's regulatory toolbox."

As far as the electricity market is concerned, Albania has yet to establish a spot market for electricity, the report notes. As long as there is no power exchange, competition is distorted by a public service obligation. All customers below 35 kV continue to be supplied by the universal supplier at regulated prices without the possibility of switching. Transmission system operator unbundling in Bosnia and Herzegovina is not in line with the provisions of the Third Energy Package. Legal unbundling of the distribution system operators in the Republic of Srpska was completed, but not in the Federation of Bosnia and Herzegovina. The country almost completed implementation in the statistics sector. On the other hand, work in the gas sector is still at an early stage.

Kosovo ranks best in the infrastructure sector, where the implementation is almost completed, but the secretariat said market liberalization has stalled. Montenegro's progress in renewable energy in transport is relatively high, at 28% and implementation in the energy efficiency sector is almost complete. There are lags in the areas of oil, gas and infrastructure. However, Montenegro still has no gas network. North Macedonia was praised for committing to phase out coal by 2028 but the report shows it has done little in terms of power market reform. Reforms in the infrastructure sector are yet to begin. Serbia upgraded its legal framework in the sectors of climate, energy efficiency, electricity and renewables but its track record continues to be weighed down by its failure to unbundle all of its transmission system operators as required by the Third Energy Package, the Energy Community Secretariat said.

Carbon Pricing

According to former Energy Community Director Janez Kopac, the lack of carbon pricing mechanisms threatens the contracting parties' long-term integration with EU markets. Speaking to ICIS[10], Mr. Kopac said the uptake of the EU's Third Energy Package – which requires EU members states to create competitive, transparent markets – has been increasing in all nine Energy Community states in recent years, with the exception of Bosnia and Herzegovina, which has constitutional issues that need to be solved first. "The best [in transposing and implementing EU rules] have been Montenegro and North Macedonia for electricity and Ukraine for natural gas," he said, shortly after the launch of the Energy Community's annual implementation report on November 15, 2021. Mr. Kopac further noted that the key to success had been the trust that the Energy Community Secretariat has earned thanks to its independence. For example, he said the North Macedonian government refrained from intervening in the electricity market because the country imports most of its electricity. In Montenegro's case, there was a pressing need to reform because the country built a subsea electricity cable to Italy. Finally, Ukraine had to liberalise its natural gas market as part of credit arrangement with the International Monetary Fund and in order to secure a long-term gas transit agreement with Russia in 2019.

The biggest difficulty ahead, says Mr. Kopac, lies in a growing rift between Energy Community and EU countries caused by misalignment of the adoption of a carbon pricing mechanism. The adoption of such a mechanism is voluntary and so far only Montenegro adopted a credible carbon price of €24.00/tCO_2e. "The commission is the only body that can propose new elements of EU Acquis for the transposition in the Energy Community and it seems that an emission trading scheme will be proposed sometime around 2025. Contracting parties could be more active by themselves but right now they are waiting for the EU to push them with legal action".

While most contracting parties are lagging behind EU member states in pursuing a viable carbon pricing mechanism, many are still forking out subsidies for coal-fired capacity. "The Energy Community Secretariat identified

[10] ICIS (2021), "Energy Community countries' energy regulation more aligned with EU", https://www.icis.com/explore/resources/news/2021/11/16/10706271/energy-community-countries-energy-regulation-more-aligned-with-eu

several potential illegal state aid cases in the contracting parties. We urged all national authorities and the Competition directorate to act but all we received instead was silence," Kopac added.

Some contracting parties, such as Bosnia and Herzegovina, Serbia or Kosovo, which have strong coal dependency, are simply not planning to phase it out until 2050, despite promises for the provision of national climate funds that would be co-managed by the EU and national authorities in a bid to help speed up the decarbonization process. Obviously the above three countries consider coal and lignite to be an indispensable part of their energy security arrangements and hence, they are not willing to endanger fulfillment of their power requirements in exchange of dubious substitutes and the blurred vision of a far in the future carbon neutrality. This seems to be the position of many countries in SE Europe as energy security ranks very high in their overall energy policy.

Market Integration

Another major challenge ahead for Western Balkans is ensuring that governments remain compliant with EU regulations and pursue the integration of their markets. According to Energy Community officials, the current energy crisis had been used to justify governmental price interventions in Serbia, Albania, as well as the Ukrainian gas markets, but also in some EU countries. "As long as markets are not fit for purpose, there will always be the same excuse. [Governments must] stop intervening in electricity and gas incumbents' activities by adopting indirect regulation that leads to never ending cross-subsidisation," note the above officials, pointing out that in some cases governments use the pretext of security of supply to justify unviable economic measures.

There is obviously a need for deeper integration of contracting parties with EU states, but momentum has been lost and any prospects for treaty amendments have hit the buffers.

Energy Community officials underline that Contracting Parties which are expecting to extend the shelf life of their assets operating on natural gas should consider fast-tracking their transition to cleaner forms of generation by attracting more investments in renewables. "Building new gas infrastructure now could be stranded assets very soon," points out Mr. Kopac. Needless to say that such views are not shared by most governments in the region for reasons already explained.

1.5 The Evolving SEE Energy Landscape

A cursory examination of the basic economic and energy statistics will reveal the great disparities that exist between the various countries. There are marked differences over a wide spectrum of economic and social parameters to an extent that makes one wonder if there is any merit in pursuing a common stand in the hope of establishing integrated strategies for the area.

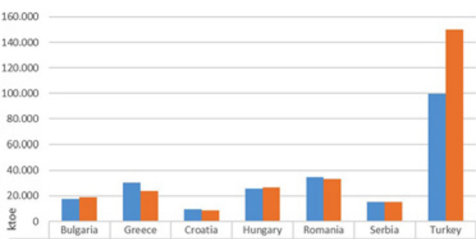
On the other hand, it is evident that the relatively small and fragmented states of SE Europe, especially in Western Balkans, cannot move alone and truly pursue independent economic, let alone energy policies. Even the largest states of the region, such as Turkey, which enjoys a strong geopolitical position and is driven by a big economy, needs to develop close ties and partake into the energy policies of neighboring countries, like Bulgaria and Greece, in order to advance its own energy interests.

Thus, a sense of interdependence becomes inevitable. As a result, all countries have their eyes set towards the broader region of SE Europe where the development of meaningful economic relations and cooperation, based on mutually beneficial policies, have energy as their common denominator.

However, one should adopt a realistic approach when investigating the energy situation of the region by identifying at an early stage the serious imbalances that exist between the East and West Balkans in terms of energy demand, supply and infrastructure. As part of our integrated examination of the peculiarities of SE Europe, we must single out Turkey, whose position, because of its size (much bigger than any of the other state of the region) and geographical position has to be viewed in context. Turkey's role, in relation to the rest of SE European countries, in the forging of common energy strategies and energy market integration (in both electricity and gas) is as important as that of Greece in influencing the developments in the rest of the region.

The abbreviated energy data for the region, as shown on Figure 1.5, which includes the gross inland consumption for a representative group of countries, can help us understand the region's widely diverse energy scene. This is characterized not only by huge market disparities in terms of population, economic development and energy infrastructure (e.g. installed electricity capacity, gas use, oil consumption), but also by the region's great dependence on energy imports (see Figure 1.6).

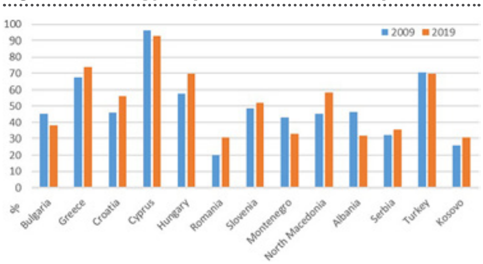
Figure 1.5 **Gross Inland Consumption in Selected SEE Countries**



	Bulgaria	Greece	Croatia	Hungary	Romania	Serbia	Turkey
2009	17.571,000	30.339,396	9.569,836	25.840,354	34.791,721	15.230,394	99.721,049
2019	18.847,668	23.551,592	8.790,716	26.708,150	33.205,199	15.420,374	150.123,29

Sources: Eurostat, IENE

Figure 1.6 **Energy Dependence in SE Europe**



Sources: Eurostat, IENE

Indeed the region's overdependence on energy imports is a defining characteristic of its economy and in that respect considerable emphasis is given in the present "Outlook" on the negative economic impact from substantial oil and gas imports but also on the efforts currently in place to develop further indigenous hydrocarbon production and promote RES utilization (see Chapters 8 and 11 respectively).

SE Europe is strategically located between the hydrocarbon-rich regions of the Middle East and the Caspian basin, including Russia, and the big energy-consuming states of Western and Central Europe. Even with the prospect of an accelerated decarbonization in the years to come, this observation is still valid as gas will for the foreseeable future provide much needed base load for power generation for most countries in the region. Thus, the region is well positioned to play an important role, as an energy bridge in the transiting of hydrocarbon resources and in the diversification of oil and gas supplies, both within the region itself and for Europe as a whole, despite the fact that due to the coronavirus pandemic, which still exists, hydrocarbon exploration activities have been limited globally and regionally.

At present, gas markets in the East Balkans, although in existence for many years, are still at an early stage of truly commercial development, while those in Western Balkans are small, and in some areas non-existent, but have an excellent potential for growth, especially now where new gas pipeline projects, including Turk Stream and the TAP-TANAP system, are currently in operation. It remains to be seen though if gas will manage to enter the energy mix of countries like Albania, Kosovo and Montenegro which have no gas infrastructure at all, as strong opposing forces, within the EU mechanism, argue that a straight leap into renewables is not only preferable but desirable in the context of energy transition and long-term carbon neutrality.

However, such arguments are not at all convincing to the political leaderships of the above countries which see the entry of gas into their systems as the fastest and easiest way to lower emissions and also increase security supply by diversifying their energy mix. It should also be noted as a general observation that many countries in the region depend heavily on indigenous coal and lignite for power generation and will continue to do so for some years to come.

Decarbonization targets vary between 2028 in the case of Greece to 2040 in the case of Bulgaria and 2050 for Serbia. Cost-effective expansion of generating capacity would produce a more diversified mixture, including new technologies with a lot more efficient and cleaner lignite power plants (producing less CO_2 emissions), use of CCUS technologies, gas-fired combined cycle and CHP, nuclear power, and renewables, including hydropower, with the balance being determined by the prevailing prices for fuel and CO_2 emissions. This would support a more sustainable energy mix for the region with reduced carbon emissions and a lower overall energy intensity.

The energy mix for SE Europe as a whole for 2000, 2009 and 2019, with and without Turkey, is presented in Figures 1.7-1.12. In our various calculations, a distinction is made as to Turkey's participation (with and without Turkey) as the country's size and energy magnitudes are significant in comparison with those of other countries in the region and therefore if seen together with the East and West Balkan region, they tend to distort the overall picture. Drawing comparisons between the energy mixes in SEE between 2000, 2009 and 2019, either with or without Turkey, we are forced to admit that there appears to be a strong inertia with regard to change as oil and solid fuels appear to maintain their dominant position throughout the 20-year period. Including Turkey, solid fuels in SE Europe still correspond to a very strong 24% of gross inland consumption in 2019, as compared to 28% in 2000. Similarly with oil, their use has diminished by just 3% between 2000 and 2019. Whereas in the case without Turkey, solid fuels' use has shrinked from 27% in 2000 to 21% in 2019. A logical sequence following EU's strong decarbonisation drive and the imposition of emission costs for coal and lignite power generation.But in the case of oil consumption, with the bulk of it used for transportation, and the lack of alternatives, the picture appears almost static. So, in the case of "with Turkey", oil use corresponded to 36% in 2000, which had dropped to only 33% in 2019. Whereas in the case of "without Turkey", the inertia with regard to oil use is even stronger since in 2000 oil consumption corresponded to 34% with this number remaining the same 20 years later.

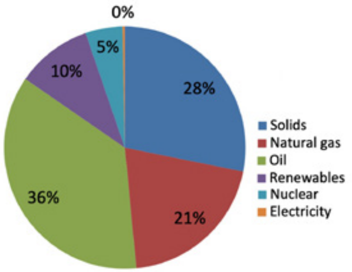
When it comes to gas use despite the high hopes for this fuel over the years to provide a substitute to a large extent to solid fuels, this wishful thinking has not materialised. So, in the case "with Turkey", gas consumption in 2000, corresponded to 21%, having only risen to 22% by 2019. In the case of "without Turkey", which covers the entire Balkans peninsula, gas use from 22% in 2000 has dropped to 20% in 2019, clearly showing a determined stand by certain countries to avoid overexposure and reliance to a largely imported fuel. And although gas consumption per se has increased overall in SEE during the past 20 years, the dominance of solid fuels, supported by the rise of renewables, has meant that gas use as a percentage in the energy mix has maintained a steady position.

It should be noticed, that the total gross energy consumption in the region from 222.7 Mtoe in 2000 has been increased to 251,2 Mtoe in 2009 and 300.6 Mtoe in 2019. With Renewable Energy Sources (RES) we have a far more dynamic situation in the case of both "with" and "without Turkey". In 2000, the portion of RES corresponded to 10% and 9% respectively for the "with Turkey" and "without" options, with inputs mainly contributed by large hydro power stations and biomass and very limited geothermal, wind and solar geothermal,. Fast forward to 2019 and the situation has dramatically changed as in both cases we note a significant increase. In the case "with Turkey", RES input rises to 16% in 2019 from 10% in 2000 whereas in the case "without Turkey" the change is even more profound as the RES share has risen from 9% in 2000 to 16% in 2019.

Nuclear power maintains its share unchanged at 8% over the 20-year period in the case of "without Turkey". Whereas in the case "with

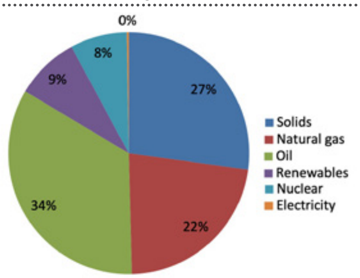
Turkey", nuclear's share becomes smaller from 5% in 2000 to 4% in 2019. This can be explained from Turkey's huge inputs from solid fuels, gas and RES which have substantially increased over the 20-year period. Finally, we have the 1% input from electricity for both cases (with and without Turkey) which means that the region has become a net electricity importer. A change of status, compared to twenty years ago, when the countries of the region were either self-sufficient in electricity or even net exporters as was the case of West Balkans, Romania and Bulgaria.

Figure 1.7 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2000 (Total=222.7 Mtoe)**



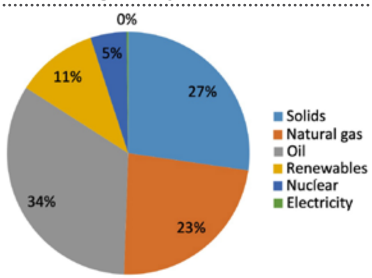
Sources: Eurostat, IENE

Figure 1.8 **Gross Inland Consumption (%) in SE Europe, without Turkey, 2000 (Total=145.4 Mtoe)**



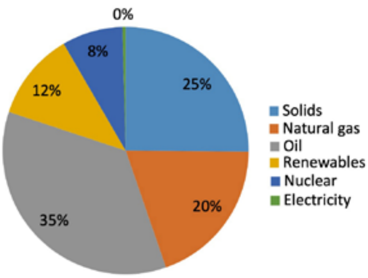
Sources: Eurostat, IENE

Figure 1.9 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2009 (Total=251.2 Mtoe)**



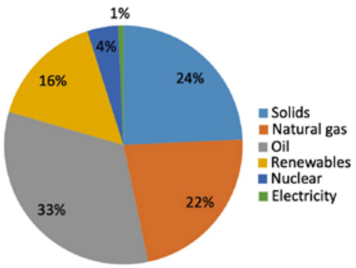
Sources: Eurostat, IENE

Figure 1.10 **Gross Inland Consumption (%) in SE Europe, without Turkey, 2009 (Total=151.5 Mtoe)**



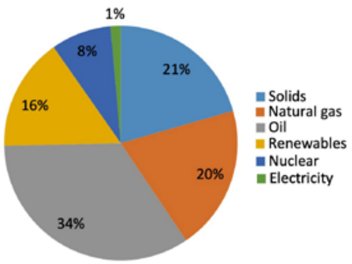
Sources: Eurostat, IENE

Figure 1.11 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2019 (Total=300.6 Mtoe)**



Sources: Eurostat, IENE

Figure 1.12 **Gross Inland Consumption (%) in SE Europe, without Turkey, 2019 (Total=151.4 Mtoe)**



Sources: Eurostat, IENE

Looking at the broad energy picture of the region (with and without Turkey), one can see that solid fuels, which include coal and lignite, maintain their strong position, despite the fact that their share decreased at 24% in 2019, compared to 27% in 2009 in the case of 'with Turkey'. Likewise, oil's share remained strong and stable at 33% in 2019, compared to 2009. Solid fuels' and oil's dominance as well as the inherent difficulties in decarbonizing the region are discussed in detail in the relevant Chapters of the present study (see Chapters 3, 4, 9.2 and 10).

The role of natural gas is also important, the share of which in the case that Turkey is included in our calculations, remained almost the same at 22% in 2019, compared to 23% in 2009. This is understandable if we consider regional developments during 2009-2019, where natural gas did not made significant inroads in the West Balkans as they remained largely without gas infrastructure, while gas use in Bulgaria and Romania did not increase substantially. It is only last year (2020), where the operation of new gas infrastructure projects, such as Krk FSRU in Croatia, the Turk Stream and the TANAP-TAP system, provided more gas quantities to the region.

But the real reason for gas stagnation in SEE is that solid fuels have retained their strong position together with rising inputs from RES. If we are to exclude Turkey, where gas use subsided over the last 2-3 years, we see slightly higher gas use as decarbonization takes hold in Greece and Romania.

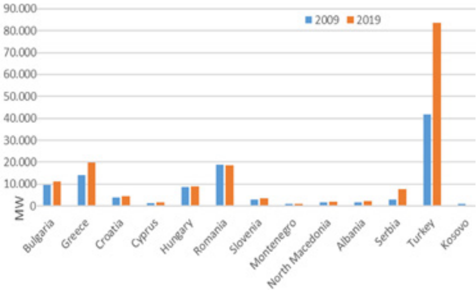
In addition, nuclear's share for power generation, including Turkey, remained small (at 5%) in 2019, compared to 2009, as no new nuclear capacity has come on stream, while the share of renewables increased considerably during this period, making significant impact in power generation. This is of course set to change over the next decade with the entry of nuclear power in Turkey and expansion of its use in Romania and possibly in Bulgaria while Serbia recently (2021) announced its interest for the installation of a nuclear plant.

A common feature of SE Europe (with the exception of Greece and Turkey) is that key elements of the region's energy infrastructures (e.g. gas pipelines, major thermal power plants) were built in the 1960s and 1970s, based on standard Soviet era technology. This concentration in age and type of technology often, combined with poor maintenance, creates serious challenges in terms of infrastructure upgrades, especially now where there is an urgent need towards decarbonisation, meaning the replacement of ageing infrastructure and the abandonment of lignite-fired power plants.

Almost all countries (with the exception of Albania, Romania and Croatia) depend heavily on hydrocarbon imports, from outside the region. Shared infrastructure also creates a high level of interdependence within the region itself. For instance, all countries participate in extensive daily and seasonal exchanges of electricity, while Serbian oil refineries rely on deliveries through the Croatian pipeline network and North Macedonia imports all its crude via pipeline from Greece. An analysis of the data reveals the region's huge dependence on oil and gas imports (see Fig 1.6). The region was 87% dependent on outside oil supplies in 2019, a situation which was even worse in the case of natural gas where import dependence exceeded 88%. With consumption set to increase over the coming years, the energy supply situation is bound to worsen at a time when the international situation in terms of security of supply tends to become more uncertain.

The electricity sector and its further expansion constitute the backbone for the region's economic and energy development. With about 165 GW of total installed electricity capacity in 2019, the impression is given that the region's electricity system is more than adequately supplied. However, this is not absolutely true as important disparities exist between the various countries' installed capacity, as can be clearly seen in Figure 1.13. It should be pointed out that the total power generation in the region from 486.1TWh in 2009 has been increased to 581.8TWh in 2019.

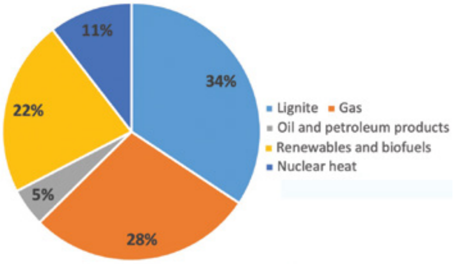
Figure 1.13 **Total Electricity Installed Capacity in SE Europe (2009 and 2019)**



Sources: Eurostat, IENE

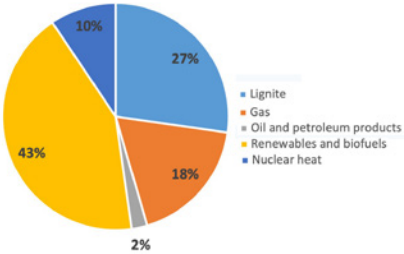
On the other hand, the region's electricity mix, which is shown in Figures 1.14 and 1.15 for 2009 and 2019 respectively, is not adequately diversified, as large thermal plants, mostly coal, lignite and gas fired, provide the bulk of power generation. However, the situation is different at national level as the prime fuel for power generation varies considerably from country to country. In the West Balkans, hydroelectricity as well as coal/lignite form the basis for power generation, with Albania relying almost 100% on hydro, while Kosovo depends 100% on lignite and the other countries enjoy a mix based on oil, gas and renewables. On the other hand, in the East Balkans, the energy mix for power generation is a lot more diversified, with the addition of nuclear energy and the wider use of natural gas, which is the case in Bulgaria and Romania, whereas Greece and Turkey rely heavily on lignite and thermal coal, but with growing inputs from renewables, including wind, solar photovoltaic and hydro and soon nuclear in the case of Turkey.

Figure 1.14 **Power Generation Mix in SE Europe, including Turkey, 2009 (Total=39.6 Mtoe)**



Sources: Eurostat, IENE

Figure 1.15 **Power Generation Mix in SE Europe, including Turkey, 2019 (Total=45.5 Mtoe)**



Sources: Eurostat, IENE

Since the early 2000, electricity transmission system operators (TSOs) in the region have focused on two priority areas: (a) the rehabilitation of grids and interconnections in the area of Western Balkans, and (b) the building of new interconnections in order to handle even more demanding electricity flows between the various countries as witnessed by latest developments throughout the region.

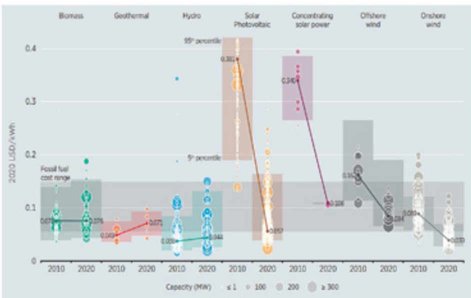
Both were and will be necessary over the next few years, but one important challenge that should be taken into consideration is the decrease in the cost of electricity grids, which is difficult as the soil morphology is different on a country-by-country analysis. The same also stands for renewables.

A substantial fall in the cost of renewables (CAPEX and OPEX) has been recorded over the last decade and thus, renewables are becoming more and more competitive in the energy landscape. More specifically, based on IRENA's data[11], the decade between 2010 and 2020 saw dramatic improvement in the competitiveness of solar and wind power technologies, as the cost of electricity from utility-scale solar photovoltaics decreased by 85%, followed by concentrating solar power or CSP (68%), onshore wind (56%) and offshore wind (48%), as shown in Figure 1.16.

[11] IRENA (2021), "Renewable Power Generation Costs in 2020", https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020

The last decade has seen CSP, offshore wind and utility-scale solar PV all join onshore wind in the cost range for new capacity fired by fossil fuels, when calculated without the benefit of financial support. Indeed, the trend is not only one of renewables competing with fossil fuels, but significantly undercutting them.

Figure 1.16 **Global LCOEs from Newly Commissioned, Utility-Scale Renewable Power Generation Technologies, 2010-2020**



Source: IRENA Renewable Cost Database

Note: This data is for the year of commissioning. The diameter of the circle represents the size of the project, with its centre the value for the cost of each project on the Y-axis. The thick lines are the global weighted-average LCOE values for plants commissioned in each year. Real WACC was 7.5% in 2010 and 5% in 2020 for OECD countries and China, and 10% in 2010 and 7.5% in 2020 for the rest of the world. The single band represents the fossil-fuel fired power generation cost range, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.

Source: IRENA

This development has a positive impact on the acceptability of renewables. Cheap renewables mean that more of them can be used; thus, facilitating global energy transition process and satisfying the new "Fit for 55" package as well as the Glasgow Climate Pact in the aftermath of COP26. However, the world is still a long way from producing all of its required electricity from renewables, as these sources, especially wind and solar, are intermittent and energy storage technologies have not been adequately developed.

Overall, examining the energy situation at regional level, we can see those changes in the energy sector, are mainly driven by energy transition considerations in the EU country block and by energy security in the rest, including Turkey Israel and West Balkans. Moreover, these changes are taking place at widely differing speeds and on the basis of diverse criteria. A situation likely to change over the next decade as energy transition priorities are expected to take hold and provide the single most important energy policy driving force.

References

(1) *SEE Energy Outlook 2011, Published by IENE, (pp), Athens, 2011*

(2) *SEE Energy Outlook 2016/2017, Published by IENE (pp 1173), Athens 2017*

(3) *Energy Community implementation report (2021), https://www.energy-community.org/news/Energy-Community-News/2021/11/15.html*

(4) *Mark Mazower, "The Balkans, a short History", Modern Library, Paperback edition, Random House, USA, 2002*

(5) *De Windt, H. (1907), "Through Savage Europe: Being the Narrative of a Journey", (Undertaken as Special Correspondent of the "Westminster Gazette"), Throughout the Balkan States and European Russia, London, 1907*

(6) *There are a number of useful references on the subject of Yugoslavia's independent stance during the Tito years. See for example:*

Djilas, Milovan (1981),"Tito. The Story from Inside", London: Harcourt

Djilas, Aleksa (1991), "The Contested Country: Yugoslav Unity and Communist Revolution, 1919-1953", Cambridge MA: Harvard University Press

eremis, Thanos (2015), "The Modern Balkans" 158-188, London: LSEE

(7) *Vickers, Miranda (1995), "The Albanians: A Modern History", I.B. Tauris, London*

(8) *Mark Mazower, Op. Cit. xxix-xxx*

(9) *Mark Mazower, Op. Cit. p. 143*

(10) *Catherine Baker, «The Yugoslav Wars of the 1990s», Palgrave, Macmillan Education, London, 2015*

(11) *Yugoslav Wars, Wikipedia, https://en.wikipedia.org/wiki/Yugoslav_Wars*

(12) *Thirteenth meeting of the Accession Conference with Serbia at Ministerial level, European Council Council of the European Union, https://www.consilium.europa.eu/en/press/press-releases/2021/12/14/thirteenth-meeting-of-the-accession-conference-with-serbia-at-ministerial-level/*

(13) *IENE, Geopolitics Bulletin, No. 23, December 2021*

(14) *«New Bulgarian PM pledges U-turn on North Macedonia's EU ambitions», Financial Times, December 14, 2021, https://www.ft.com/content/0c724214-0342-47ff-98a6-1a07086d29c6*

(15) *Accession of Albania to the European Union, Wikipedia, https://en.wikipedia.org/wiki/Accession_of_Albania_to_the_European_Union*

(16) *Economist (2019), "Seeds of Suspicion", Vol 431, No. 9140*

(17) *«China's, Entry in SE Europe's Energy Sector», IENE Briefing Note No. 11, May 2019*

(18) *The Future of Chinese Investments in Europe, Stratfor, February 21, 2021; John Varuno, «China's 17+1 initiative stalls amid security concerns and broken promises», Australian Strategic Policy Institute, The Strategist, 22 October 2020; Daniel Michaels and Valentina Pop, «China Faces European Obstacles as Some Countries Heed US Presence», WSJ, 23 February 2021*

(19) *Energy Community Implementation Report, Op. Cit. (2021)*

2

Regional Economic Outlook

Regional Economic Outlook

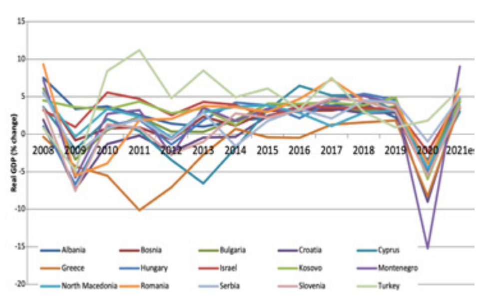
Introduction

Energy demand, by and large, is steadily correlated to economic development and growth and hence an understanding of the region's economy as a whole and on the basis of the countries included in the present "Outlook" report is of paramount importance.

Although the economies of the SE European region appear widely divergent in terms of structure and levels of development, they share a number of challenges which appear to be common to all. Among these, the global economic and financial crisis, which started in 2008, but affected all countries for many years after, and lately the coronavirus pandemic, which took hold in 2020 and still persists, have deeply affected the region collectively and each country individually. In this Chapter, we highlight the region's economic development challenges and also examine the key economic problems facing the various countries, especially taking into consideration the emerging post-pandemic climate.

At times when economic analysts employ various techniques to speculate about what the future might hold, the sobering reality is that these techniques become ineffective when the human factor is ignored. It is our view that only states whose governments possess the political determination to cease managing the economy through outdated inflexible state control mechanisms will eventually thrive. This is not to deny the necessity for state intervention when needs arise (e.g. disruption of supplies, market dysfunctions), but continuous state control cannot be the norm.This is especially relevant to the energy sector which forms a key part of the economies of most countries in SE Europe and which, as it is clearly seen in the present study, is in the process of rapid transition. As energy markets in the region (i.e. gas and electricity) move towards full liberalization, while at the same time addressing a massive influx of carbon free energy sources through open market competition, they come face to face with the remnants of monolithic state control attitudes still prevalent in several countries, some of them EU member states. It is therefore hardly surprising that achieving high rates of economic growth is not an obvious priority for many SE European countries and this certainly affects to a large extent the energy/power sector. A problem facing the SEE region is that it is not homogeneous since it includes economies of different speed and structure, such as those of EU member states (i.e. Bulgaria, Croatia, Cyprus, Greece, Romania, Hungary and Slovenia), the post-Communist Western Balkan Six (WB6) countries, which are non-EU members, but they are aspiring to become members one day, and Turkey and Israel. The key challenge for the WB6 countries is at one point to achieve European economic standards and hence, to enhance their economic growth. Therefore, in the WB6 countries, the enhancement of economic growth rates must be a result of properly planned and carefully implemented market-oriented reforms. Israel and Turkey have a combination of economic, energy and political interests that affect their economic relations, which in turn are being affected in terms of energy from all the SE European countries.The 2008 global crisis affected almost all macroeconomic variables: production, consumption, investment, unemployment and exports, while the coronavirus pandemic, still underway, had almost the same type of repercussions, albeit with a much deeper GDP slump and a different time frame (see Figure 2.1).

Figure 2.1 **Real GDP Growth (% Change y-o-y) in SE Europe, 2008-2021e**



Source: IMF World Economic Outlook (April 2021)

2.1 The European Economy and the SEE EU Member States

When discussing the regional, macroeconomic outlook, one should be aware that the SEE region is characterized by a strong variation in the structure, maturity and perspective of its respective economies. One could make a distinction among 4 groups of countries, in order to obtain a more coherent view over the development process of each country. The four groups could be summarized as follows:

(1) Greece, Cyprus and Slovenia > old EU members and part of the Eurozone (already discussed)
(2) Bulgaria, Romania, Hungary and Croatia > latest EU member states, which do not belong to the Eurozone group (already discussed)
(3) Serbia, North Macedonia, Montenegro, Bosnia and Herzegovina, Albania and Kosovo > the Western Balkan economies, EU candidates
(4) Turkey and Israel > East Med countries, with dynamic and internationally oriented economies, enjoying preferential economic relations with the EU

Even if this classification appears arbitrary on scientific or econometric terms, following references to historical and institutional resemblance, this grouping is more pragmatic as one can obtain useful insights over the development path of each country.Although the economies of the Western Balkan Six countries, together with those of Turkey and Israel, are discussed under separate sections (i.e. 2.2. and 2.3.), their economies are to a large extent influenced by economic conditions in the eurozone and in the EU Member States in SE Europe.

2.1.1 The European Economy

The near-term outlook for the European economy looks weaker than the one anticipated in the autumn of 2020, as the coronavirus pandemic has tightened its grip on the continent. The resurgence in infections since the start of 2021, together with the appearance of new, more contagious variants of the coronavirus, have forced many EU member states to reintroduce or tighten containment measures. The European economy has thus ended 2020 and started the new year on a much weaker footing. However, light is now appearing at the end of the tunnel. As vaccination campaigns gain momentum and the pressure on health systems to subside, containment measures are set to relax gradually. This is expected to have a positive impact on economic outlook for H2 2021.

The breakthrough development of vaccines in the autumn and the start of mass vaccination campaigns brightened the outlook beyond the near term. Furthermore, the agreement reached between the European Union and the United Kingdom (January 2021) on the terms of their future cooperation reduced the cost of the UK's departure from the Single Market and Customs Union, while endorsement of the Recovery and Resilience Facility is set to support EU member states on their way to a sustainable recovery.

Overall, GDP is now forecast to grow by 3.7% in 2021 and 3.9% in 2022 in the EU, and by 3.8% in both years in the euro area. It is now expected that the EU economy could reach the pre-crisis level of output earlier than anticipated back in the European Commission's Autumn (2020) Forecast, largely because of the stronger momentum in the second half of 2021 and in 2022. The speed of the recovery will, however, vary significantly across the EU. Some countries have suffered more during the pandemic than others, whereas some are more dependent on sectors such as tourism, which are likely to remain weak for some time. As a result, while some EU member states are expected to see economic output return to their pre-pandemic levels by the end of 2021 or early 2022, others are forecast to take longer.
Inflation in the euro area and the EU is expected to be slightly higher in 2021 compared to last autumn, but to remain subdued despite a temporary boost from base effects. In the euro area, inflation is forecast to increase from 0.3% in 2020 to 1.4% in 2021 before moderating slightly to 1.3% in 2022.

These projections are subject to significant uncertainty and elevated risks, predominately linked to the evolution of the pandemic and the success of vaccination campaigns.

On the positive side, the vaccination process could lead to a faster easing of containment measures and therefore an earlier and stronger recovery. Moreover, the strength of the rebound could surprise on the upside driven by a burst of post-crisis optimism that would unleash stronger pent-up demand and innovative investment projects, thanks to historically high household savings, low financing costs, and supportive policies. On the negative side, the pandemic could prove more persistent or turn out more severe in the near term, pushing back the expected recovery. There is also a risk of deeper scars in the fabric of the European economy and society inflicted by the protracted crisis, through bankruptcies, long-term unemployment, and higher inequalities. The uncertainties around the forecast are illustrated by the scenario analysis presenting alternative paths for the European economy under different sets of assumptions. Last, but not least, an ambitious and swift implementation of the NextGenerationEU programme, including its Recovery and Resilience Facility, should provide a strong boost to the EU economy.

Table 2. 1 **Overview of the EU's Winter 2021 Interim Forecast**

Real GDP Growth	Winter 2021 Interim Forecast 2020	2021	2022	Autumn 2020 Forecast 2020	2021	2022
Euro area	-6.8	3.8	3.8	-7.8	4.2	3.0
EU	-6.3	3.7	3.9	-7.4	4.1	3.0
Inflation						
Euro area	0.3	1.4	1.3	0.3	1.1	1.3
EU	0.7	1.5	1.5	0.7	1.3	1.5

Source: European Commission

2.1.2 The SEE EU Member States

The EU member states in SE Europe include seven countries, i.e. Greece, Cyprus, Slovenia, Bulgaria, Croatia, Hungary and Romania. For comparison purposes, estimates for 2021 and 2022 from both the European Commission and IMF will be provided, while a country-by-country analysis of the economies follows.

Greece

Based on Eurostat's data, Greece's GDP increased by 2.3% q-o-q during the third quarter of 2020, reflecting the reopening of the economy and the temporary easing of the containment measures at that time. The recovery in the third quarter was mainly driven by domestic demand. Economic activity in the services sector decreased sharply due to the negative impact of the COVID-19 pandemic on tourism, while construction showed some resilience. Following the re-introduction of containment measures during the fourth quarter of 2020, output growth is forecast to turn negative in quarterly terms. Overall, Greece's real GDP is expected to have declined by 10% in 2020, based on Eurostat's estimates. Containment measures are expected to weigh on Greece's recovery, with real GDP expected to grow by 3.5% in 2021, before rising to 5% in 2022, based on Eurostat's estimates. The recovery will continue to be supported mainly by private consumption, on the back of the gradual reopening of retail trade, improving consumer confidence and the supportive setting of fiscal policy in the economy. Net exports are expected to contribute positively to growth in 2021 and 2022, with the rollout of vaccination campaigns expected to support only a gradual return of tourists to Greece. Investment is forecast to recover as well but at a slower pace. The support measures adopted by the authorities have bolstered credit growth to businesses.

Unemployment stood at 16.7% in October 2020, similar to a year before, indicating that the labour market impact of the economic crisis remains relatively contained. Employment, however, decreased, primarily due to lower hirings in the tourist sector. After dropping by 1.3% in 2020, inflation is forecast to remain mildly negative in 2021 before turning positive in 2022. The negative growth in prices is mainly driven by an expected drop in service sector prices.

Table 2. 2 **Macroeconomic Performance of Greece**

Greece	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	-10,1	-7,1	-2,7	0,7	-0,4	-0,5	1,3	1,6	1,9	-8,2	3,8
GDP at current prices (billion LC)	203,3	188,4	179,6	177,3	176,1	174,2	177,2	179,7	183,4	165,8	172,2
GDP at current prices (billion USD)	282,9	242,2	238,6	235,7	195,4	192,8	200,1	212,3	205,3	189,3	209,9
GDP per capita at current prices (LC)	18277,5	16992,8	16323,4	16230,6	16219,4	16157,4	16451,4	16732,5	17102,1	15482,8	16145,7
GDP per capita at current prices (USD)	25437,0	21846,0	21679,7	21568,0	17997,4	17879,7	18578,3	19769,3	19147,5	17670,3	19672,5
Total investment (% of GDP)	14,0	12,1	12,0	11,9	12,1	12,8	12,4	13,3	12,7	13,5	13,9
Inflation (annual average)	3,1	1,0	-0,9	-1,4	-1,1	0,0	1,1	0,8	0,5	-1,3	0,2
Volume of imports of goods and services (%)	-9,6	-5,5	15,1	7,2	3,6	1,9	7,4	8,3	6,9	-14,0	3,7
Volume of exports of goods and services (%)	0,6	2,0	12,9	7,5	4,2	-0,4	8,4	8,8	7,5	-25,7	10,3
Unemployment rate (annual average)	17,9	24,4	27,5	26,5	24,9	23,6	21,5	19,3	17,3	16,4	16,6
Population (million)	11,1	11,1	11,0	10,9	10,9	10,8	10,8	10,7	10,7	10,7	10,7
General government gross debt (% of GDP)	183,9	162,0	179,0	181,5	179,0	183,4	182,4	189,9	184,9	213,1	210,1
Current account balance (% of GDP)	-10,1	-2,5	-2,6	-2,4	-1,5	-2,4	-2,6	-3,6	-2,2	-7,4	-6,6

Source: IMF World Economic Outlook (April 2021)

The forecast remains subject to large uncertainty. The developments regarding the global health crisis and the vaccination rollout will be crucial for the recovery of the tourism sector and the speed of recovery in the private sector after the expiry of government support measures. In addition to that, geopolitical tensions in the region and the migration crisis add further uncertainty to the forecast. On the upside, the European Commission's forecast does not incorporate the impact of the Recovery and Resilience Plan, which could provide a significant boost to domestic demand once implemented.

Cyprus

Based on Eurostat's data, Cyprus's real GDP rebounded strongly in the third quarter of 2020 (+9.4%, compared to the second quarter). This rebound was driven by domestic demand, which was mainly underpinned by fiscal stimulus, while exports of goods and services decreased. The recovery lost some steam towards the end of the year as lockdown measures were reintroduced to combat a resurgence in COVID-19 infections. Economic sentiment and consumer confidence worsened in the last two months of the year and again in January 2021. Based on Eurostat's estimates, Cyprus's real GDP is estimated to have contracted by 5.8% in 2020.

In 2021, a partial recovery is forecast, with real GDP growth expected to reach 3.2%. Containment measures have become stricter since the start of the year but they affect a smaller share of economic activity than in spring 2020. As restrictions are expected to continue until vaccinations pick up and cases drop, the recovery is expected to take place mainly in the second half of 2021. Domestic demand is again expected to be the main contributor to growth. Policy measures adopted to mitigate the impact of the crisis have been extended into 2021, and some of them, such as the loan repayment moratorium, are planned to remain in place at least until June 2021.

These measures should continue to support employment, household incomes and help businesses to maintain their capacity. Furthermore, construction activity has so far escaped disruption from the lockdown measures. Tourism, a key sector for Cyprus, has borne the brunt of the COVID-19 pandemic. Receipts from tourism have significantly declined by around 85% in 2020. This trend is expected to be only partially reversed in 2021. On the supply side, interruptions to airline capacity and, on the demand side, varying progress with vaccinations in Cyprus's main tourist markets and lower confidence in air travel are expected to weigh on the sector's recovery. In 2022, real GDP is forecast to grow by 3.1% and return to its 2019 level, based on Eurostat's estimates. This will be mainly on the back of domestic demand, as well as a small positive contribution from net exports. Future spending related to the Recovery and Resilience Facility is not included in the European Commission's forecast and constitutes an upside risk.

Cyprus's inflation fell to -1.1% in 2020, dragged down by lower prices for energy and processed foods. In addition, the VAT rate reduction in the hospitality industry led to a fall in the prices of services. Inflation is forecast to turn positive again in 2021 and 2022, at 0.7% and 1.1%, respectively, underpinned by higher energy and services prices.

Table 2. 3 **Macroeconomic Performance of Cyprus**

Cyprus	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	0,4	-3,4	-6,6	-1,8	3,2	6,4	5,2	5,2	3,1	-5,1	3,0
GDP at current prices (billion LC)	19,8	19,4	18,0	17,4	17,9	18,9	20,1	21,4	22,3	21,0	21,7
GDP at current prices (billion USD)	27,6	25,0	23,9	23,2	19,8	20,9	22,7	25,3	25,0	24,0	26,5
GDP per capita at current prices (LC)	23582,1	22552,6	20782,5	20314,8	21114,1	22313,9	23537,5	24799,5	25444,8	23704,7	24253,3
GDP per capita at current prices (USD)	32819,5	28993,7	27602,0	26995,2	23428,7	24692,5	26580,5	29300,3	28487,9	27053,8	29551,3
Total investment (% of GDP)	18,8	16,0	12,9	13,5	13,2	17,4	20,2	18,4	19,7	23,3	24,1

Table 2. 3 **Macroeconomic Performance of Cyprus**

Inflation (annual average)	3,5	3,1	0,4	-0,3	-1,5	-1,2	0,7	0,8	0,6	-1,1	0,5
Volume of imports of goods and services (%)	-2,6	-3,6	-4,6	7,7	9,1	10,0	12,9	4,5	2,0	-5,8	0,9
Volume of exports of goods and services (%)	7,0	-0,5	1,2	6,2	9,9	7,2	9,9	8,0	-0,4	-17,4	3,8
Unemployment rate (annual average)	7,9	11,8	15,9	16,1	14,9	13,0	11,1	8,4	7,1	7,6	7,5
Population (million)	0,8	0,9	0,9	0,9	0,8	0,8	0,9	0,9	0,9	0,9	0,9
General government gross debt % of GDP)	65,0	79,4	102,9	109,1	107,2	103,1	93,5	99,2	94,0	118,2	113,0
Current account balance (% of GDP)	-2,3	-3,9	-1,5	-4,1	-0,4	-4,2	-5,3	-3,9	-6,3	-10,3	-8,5

Source: IMF World Economic Outlook (April 2021)

Slovenia

Based on Eurostat's data, Slovenia's GDP is estimated to have contracted by 6.2% in 2020. Over the first three quarters, private consumption was 8.4% and investment 6.5% lower than in the same period in 2019. Imports fell more than exports, leading to a positive contribution from net exports. The recovery in the third quarter of last year, however, was followed by a strong resurgence in COVID-19 infections and the introduction of new restrictions in the fourth quarter that dampened economic sentiment and reduced private consumption significantly. The impact of the crisis was softened by extensive government measures to support employment and limit insolvencies. Still, employment decreased and the unemployment rate increased slightly.

The pandemic and its associated restrictions continue to exert a strong influence over the economy in early 2021, particularly in the services sector. Industrial production and construction are expected to be less affected. The economic situation is expected to gradually improve as more people are vaccinated and restrictions are relaxed, leading to stronger growth in the second half of the year.

Overall, GDP is forecast to grow by 4.7% in 2021, based on Eurostat's estimates, supported by both strong domestic demand and positive net exports. Thereafter, the economy is expected to grow by 5.2% in 2022, driven by the same factors as in 2021. GDP is expected to exceed its end-2019 level by the end of 2022.

Once support measures end, the recent increase in the minimum wage could place additional strain on struggling companies in the services sector. This constitutes a downside risk to the forecast. The forecast factors in some of the measures expected to be funded under the Recovery and Resilience Facility representing about 0.6% of GDP. Higher use of the facility is an upside risk. The sharp decline in oil prices in March 2020 led to deflationary pressures that were still being felt at the end of 2020 despite the partial recovery in energy prices.

Overall, energy prices decreased by 0.3% in 2020. Inflation is expected to remain very low in the beginning of 2021 and to increase somewhat in the second half of the year. Overall, prices are expected to increase by 0.8% in 2021. In 2022, taking into account the projected recovery and assumed increase in energy prices, inflation is expected to reach 1.7%.

Table 2.4 **Macroeconomic Performance of Slovenia**

Slovenia	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	0,9	-2,6	-1,0	2,8	2,2	3,2	4,8	4,4	3,2	-5,5	3,7
GDP at current prices (billion LC)	37,1	36,3	36,5	37,6	38,9	40,4	43,0	45,9	48,4	46,3	48,5
GDP at current prices (billion USD)	51,6	46,6	48,4	50,0	43,1	44,8	48,6	54,2	54,2	52,8	59,1
GDP per capita at current prices (LC)	18075,7	17637,3	17706,4	18259,5	18834,2	19592,8	20818,6	22189,3	23255,5	22089,8	23065,4
GDP per capita at current prices (USD)	25156,1	22674,5	23516,5	24264,0	20898,9	21681,3	23510,1	26216,4	26036,8	25210,7	28103,8
Total investment (% of GDP)	21,7	18,8	19,6	19,4	19,2	18,4	20,0	21,2	20,7	20,6	21,3
Inflation (annual average)	1,8	2,6	1,8	0,2	-0,5	-0,1	1,4	1,7	1,6	-0,1	0,8
Volume of imports of goods and services (%)	5,3	-3,5	2,1	4,2	4,3	6,3	10,7	7,2	4,4	-10,2	9,7
Volume of exports of goods and services (%)	6,9	0,5	3,1	6,0	4,7	6,2	11,1	6,3	4,1	-8,7	7,8
Unemployment rate (annual average)	8,2	8,9	10,2	9,7	9,0	8,0	6,6	5,1	4,4	5,1	5,4
Population (million)	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1
General government gross debt (% of GDP)	46,5	53,6	70,0	80,3	82,6	78,5	74,1	70,3	65,6	81,5	80,5
Current account balance (% of GDP)	-0,8	1,3	3,3	5,1	3,8	4,8	6,2	5,8	5,6	7,3	6,9

Source: IMF World Economic Outlook (April 2021)

Bulgaria

Based on Eurostat's data, Bulgaria's economic activity declined markedly in 2020 due to the COVID-19 pandemic. Private consumption dynamics followed the introduction and subsequent relaxation of containment measures. In late November 2020, a second wave of the pandemic led to the re-introduction of containment measures which are still in place and which continue to weigh on household consumption and business sentiment in trade and the services sector. Private investment remained depressed throughout the first nine months of 2020, while public sector investment increased markedly in Q3 2020. Although exports within the EU have been recovering since mid-2020, sales to non-EU countries have continued to falter. The COVID-19 pandemic has led to a significant loss in revenues from foreign tourists, which typically account for around three quarters of revenues from tourist accommodation. Overall, Bulgaria's real GDP is expected to fell by 4.9% in 2020, based on Eurostat's estimates.

Looking forward, domestic demand is forecast to remain subdued in the first half of 2021, given the assumed extension of containment measures. The eventual re-opening of the economy should provide a boost to consumption and investment in the second half of 2021. Goods exports are expected to gradually recover from the second quarter onwards, while foreign tourists are expected to start returning in the third quarter. The recovery in foreign tourism, however, is subject to a downside risk linked to the relative rates of vaccination and contagion in Bulgaria compared to alternative tourist destinations. Against this backdrop, real GDP growth is forecast to reach 2.7% in 2021, before accelerating to 4.9% in 2022 on the back of strong domestic demand and more buoyant exports. As the European Commission's forecast does not take into account the implementation of the Recovery and Resilience Plan, an upside risk to public investment emerges.

Annual average inflation fell to 1.2% in 2020 due to falling energy prices and abating price dynamics in services and unprocessed foods. Inflation is set to increase to 1.7% in 2021 and 1.8% in 2022, driven by price increases in processed foods and services.

Table 2. 5 **Macroeconomic Performance of Bulgaria**

Bulgaria	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021e**
Real GDP (% change)	2,4	0,4	0,3	1,9	4,0	3,8	3,5	3,1	3,7	-3,8	4,4
GDP at current prices (billion LC)	80,7	82,2	82,0	83,9	89,4	95,1	102,3	109,7	119,8	117,5	124,9
GDP at current prices (billion USD)	57,4	54,0	55,6	56,9	50,6	53,8	59,1	66,3	68,6	68,6	77,8
GDP per capita at current prices (LC)	11015,6	11289,5	11310,9	11647,1	12491,6	13395,2	14517,0	15677,5	17229,7	16998,8	18172,9
GDP per capita at current prices (USD)	7832,2	7417,3	7675,9	7900,7	7079,8	7575,8	8382,0	9470,6	9863,0	9919,3	11321,3
Total investment (% of GDP)	21,5	22,0	21,1	21,6	21,0	19,0	19,9	21,3	21,1	19,4	17,7
Inflation (annual average)	3,4	2,4	0,4	-1,6	-1,1	-1,3	1,2	2,6	2,5	1,2	1,0
Volume of imports of goods and services (%)	9,9	5,6	4,3	5,2	4,8	5,2	7,4	5,7	5,2	-5,9	5,1
Volume of exports of goods and services (%)	12,6	2,0	9,6	3,1	6,4	8,6	5,8	1,7	3,9	-9,1	5,4
Unemployment rate (annual average)	11,4	12,4	13,0	11,5	9,2	7,7	6,2	5,2	4,2	5,2	4,8
Population (million)	7,3	7,3	7,2	7,2	7,2	7,1	7,1	7,0	7,0	6,9	6,9
General government gross debt (% of GDP)	14,4	16,6	17,2	26,3	25,4	27,1	23,0	20,1	18,4	23,8	25,5
Current account balance (% of GDP)	0,3	-0,9	1,3	1,2	0,1	3,2	3,5	1,0	3,0	0,1	1,4

Source: IMF World Economic Outlook (April 2021)

Croatia

Based on Eurostat's data, Croatia's economy is estimated to have contracted by 8.9% in 2020. This sharp decline is mainly attributable to the impact of the COVID-19 pandemic on service exports, particularly tourism, which suffered greatly due to the fall in demand for air travel and the imposition of travel restrictions in many countries. Private consumption also fell, reflecting the accumulation of involuntary and precautionary savings. Following a better-than-expected third quarter, GDP is estimated to have contracted again towards the end of the year as pandemic suppression measures were reintroduced in December.

Based on Eurostat's estimates, Croatia's real GDP is forecast to bounce back by 5.3% in 2021, as domestic demand should rebound once pandemic containment measures are phased out and more people are vaccinated. Pent-up demand[1], coupled with a gradual recovery in the labour market, is expected to boost private consumption. Investment should rebound on the back of the already strong dynamics in the construction sector, supported by rebuilding efforts following the strong earthquakes in the Banija region and Zagreb in December 2020. A gradual pick up in longer-term investment projects, is also expected. The recovery in external demand, however, is expected to be uneven. Goods exports are expected to increase strongly on the back of the improved global outlook but services exports are projected to remain subdued in both 2021 and 2022 compared to their 2019 levels. This is mainly because the recovery in the travel and hospitality sectors is likely to take several years. The European Commission's forecast does not include any measures expected to be funded under the Recovery and Resilience Facility, posing an upside risk to the growth projections.

Based on Eurostat's data, Croatia's inflation rate dropped to 0% in 2020 on the back of a strong decline in energy prices, while core inflation remained broadly stable at around 1%.

As the effect of last year's fall in oil prices dissipates, inflation is expected to pick up slightly in 2021 but should remain subdued throughout the forecast horizon (1.2% in 2021 and 1.5% in 2022).

Table 2. 6 **Macroeconomic Performance of Croatia**

Croatia	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	-0,2	-2,4	-0,4	-0,3	2,4	3,5	3,4	2,8	2,9	-9,0	4,7
GDP at current prices (billion LC)	334,2	331,0	332,0	331,3	339,7	351,2	367,5	385,4	402,3	369,8	391,3
GDP at current prices (billion USD)	62,5	56,6	58,2	57,6	49,5	51,6	55,5	61,4	60,8	56,9	65,2
GDP per capita at current prices (LC)	78064,2	77557,4	78004,9	78179,6	80795,0	84139,7	89091,2	94246,3	98902,7	91409,5	97490,7
GDP per capita at current prices (USD)	14608,2	13257,0	13673,4	13600,8	11780,6	12362,6	13450,1	15009,7	14935,9	14072,1	16246,5
Total investment (% of GDP)	19,9	18,8	19,4	18,9	20,6	21,0	22,0	23,4	22,7	24,4	24,0
Inflation (annual average)	2,3	3,4	2,2	-0,2	-0,5	-1,1	1,1	1,5	0,8	0,3	0,7
Volume of imports of goods and services (%)	2,5	-2,4	3,2	3,5	9,4	6,5	8,4	7,5	6,3	-16,2	11,4

1 Pent-up demand refers to a situation where demand for a service or product is unusually strong.

Table 2. 6 **Macroeconomic Performance of Croatia**

Volume of exports of goods and services (%)	2,3	-1,5	2,5	7,4	10,3	7,0	6,8	3,7	6,8	-26,9	16,3
Unemployment rate (annual average)	17,4	18,6	19,8	19,3	17,1	15,0	12,4	9,9	7,8	9,2	9,4
Population million)	4,3	4,3	4,3	4,2	4,2	4,2	4,1	4,1	4,1	4,0	4,0
General government gross debt (% of GDP)	64,2	70,0	81,0	84,7	84,3	80,8	77,5	74,3	72,8	87,2	86,3
Current account balance (% of GDP)	-1,7	-1,8	-1,1	0,3	3,3	2,1	3,4	1,8	2,8	-3,5	-2,3

Source: IMF World Economic Outlook (April 2021)

Hungary

Based on Eurostat's data, Hungary's economy bounced back by 11.4% q-o-q in the third quarter of 2020, after the first pandemic related lockdown ended. Industry, construction and retail sales remained strong in October and November. However, the rebound was interrupted by a second wave of the pandemic, which led to another round of restrictions from mid-November that mainly affected the hospitality, leisure and entertainment sectors. As a consequence, GDP is expected to have decreased slightly in the fourth quarter of 2020, based on Eurostat's estimates. Overall, Hungary's GDP is expected to show a 5.3% contraction in 2020, mostly driven by plummeting investment and service exports.

Consumption is also likely to show a decrease given the fall in household income and confidence and the limited opportunities to consume certain services during the lockdown. The current containment measures will start to be eased only once case numbers drop substantially or vaccines become widely available, thus they will remain a drag on GDP growth in the near-term. In addition, the manufacturing sector faces supply chain disruptions, which could hinder production in the short-term. The assumed easing of public health measures should set the stage for a quick rebound in economic activity from mid-2021.

Based on Eurostat's estimates, Hungary's real GDP is forecast to grow by 4% in 2021 and by 5% in 2022, supported by all final demand components. There are upside risks to the European Commission's forecast as the baseline projection does not include any measures funded by the Recovery and Resilience Facility.

The unemployment rate stood at 4.3% in December 2020, almost unchanged compared to previous months. However, an increasing share of employees reported zero working hours and household unemployment expectations also rose. The government has provided some support to preserve employment in the sectors most affected by the second lockdown, which is mitigating its negative economic impact. Job creation is expected to resume after the economy returns to growth, but lingering labour market slack is likely to temper wage growth.

Inflation eased in the last months of 2020 as food and fuel prices decreased. The country's inflation was at 3.4% in 2020 and it is projected to remain at 3.5% in 2021, based on Eurostat's estimates, due to the pass-through of earlier currency depreciation and rising excise duties on tobacco. After these temporary factors fade, inflation is expected to ease to 2.9% on the back of the subdued growth of unit labour costs.

Table 2. 7 **Macroeconomic Performance of Hungary**

Hungary	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	1,9	-1,4	1,9	4,2	3,8	2,1	4,3	5,4	4,6	-5,0	4,3
GDP at current prices (billion LC)	28501,5	28920,4	30290,9	32742,2	34937,3	36167,5	39233,4	43347,0	47513,9	47604,7	51141,3
GDP at current prices (billion USD)	141,8	128,5	135,4	140,8	125,1	128,5	143,0	160,4	163,5	154,6	176,5
GDP per capita at current prices (LC)	2854145,9	2911837,5	3056909,9	3314992,2	3544776,1	3679293,3	4004228,4	4433119,4	4861753,0	4872538,4	5236126,6
GDP per capita at current prices (USD)	14195,8	12935,5	13665,5	14251,8	12690,2	13069,2	14590,9	16406,1	16725,6	15820,1	18075,4
Total investment (% of GDP)	20,2	19,2	20,8	23,3	23,1	21,0	22,6	26,5	28,0	27,5	26,6
Inflation (annual average)	3,9	5,7	1,7	-0,2	-0,1	0,4	2,4	2,8	3,4	3,3	3,6
Volume of imports of goods and services (%)	4,3	-3,5	4,3	11,0	6,0	3,4	8,5	7,0	7,5	-12,7	10,0
Volume of exports of goods and services (%)	6,4	-1,7	4,1	9,2	7,4	3,8	6,5	5,0	5,8	-14,6	12,8
Unemployment rate (annual average)	10,7	10,7	9,8	7,5	6,6	5,0	4,0	3,6	3,3	4,1	3,8
Population (million)	10,0	9,9	9,9	9,9	9,9	9,8	9,8	9,8	9,8	9,8	9,8
General government gross debt (% of GDP)	80,4	78,4	77,4	76,7	75,8	74,9	72,2	69,1	65,3	81,2	80,0
Current account balance (% of GDP)	0,5	1,6	3,5	1,2	2,3	4,5	2,0	0,3	-0,2	-0,2	-0,4

Source: IMF World Economic Outlook (April 2021)

Romania

After a 12.2% contraction in the second quarter of last year, Romania's economy rebounded by 5.8% in Q3 2020, based on Eurostat's data, mainly due to a recovery in private consumption. The strong performance of the construction sector sustained gross fixed capital formation growth throughout the year. Meanwhile, net exports continued to contribute negatively to growth in 2020 despite exports recovering somewhat faster than imports in the third quarter. Industrial production made up for some of its earlier losses in the second and third quarter of 2020, but this positive performance appeared to stall in the beginning of the last quarter.

Economic activity is expected to have weakened somewhat in Q4 2020 as pandemic containment restrictions were reintroduced in response to a new wave of infections. Fiscal support measures, some of which have been extended until mid-2021, mitigated the impact of the crisis on the economy in 2020. The unemployment rate remained around 5%, as government policy measures cushioned the blow to the labour market.

Table 2. 8 **Macroeconomic Performance of Romania**

Romania	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	1,9	2,0	3,8	3,6	3,0	4,7	7,3	4,5	4,1	-3,9	6,0
GDP at current prices (billion LC)	558,9	591,8	635,0	669,7	711,9	763,7	857,9	951,7	1058,2	1049,2	1155,6
GDP at current prices (billion USD)	183,3	170,6	190,8	200,0	177,7	188,1	211,7	241,5	249,7	247,2	289,1
GDP per capita at current prices (LC)	27669,1	29448,6	31716,5	33563,9	35819,5	38645,2	43672,4	48730,1	54531,3	54310,8	59823,5
GDP per capita at current prices (USD)	9076,0	8491,0	9530,4	10021,5	8942,2	9520,4	10776,7	12363,0	12867,4	12797,1	14968,0
Total investment (% of GDP)	28,1	27,0	25,5	24,8	25,1	23,4	23,4	22,8	23,7	22,9	23,6
Inflation (annual average)	5,8	3,3	4,0	1,1	-0,6	-1,6	1,3	4,6	3,8	2,6	2,8
Volume of imports of goods and services (%)	9,7	-1,8	9,1	8,8	8,5	16,6	11,5	8,6	6,9	-4,6	11,4
Volume of exports of goods and services (%)	12,1	1,1	20,6	8,5	4,6	16,3	7,8	5,3	4,6	-9,4	12,0
Unemployment rate (annual average)	7,1	6,8	7,1	6,8	6,8	5,9	4,9	4,2	3,9	5,0	4,9
Population (million)	20,2	20,1	20,0	20,0	19,9	19,8	19,6	19,5	19,4	19,3	19,3
General government gross debt (% of GDP)	34,3	38,0	39,1	40,4	39,4	39,0	36,8	36,5	36,8	50,1	52,6
Current account balance (% of GDP)	-5,0	-4,8	-0,8	-0,2	-0,6	-1,4	-2,8	-4,4	-4,7	-5,1	-5,0

Source: IMF World Economic Outlook (April 2021)

Based on Eurostat's estimates, Romania's real GDP is forecast to grow by 3.8% in 2021 and by 4% in 2022. Private consumption is expected to recover strongly from the second half of 2021 as the rollout of vaccinations should allow for a gradual lifting of restrictions. Consumption is expected to remain robust in 2022. Investment is set to remain strong over the forecast horizon, supported by the construction sector. Exports are expected to recover against the backdrop of improved economic conditions in Romania's main trading partners. However, the contribution of net exports to growth is expected to remain negative over the forecast horizon.Future spending related to the Recovery and Resilience Facility is not included in this European Commission's forecast.

Risks to the growth forecast are tilted to the upside. Particular upside risks for Romania are a fast implementation of the Recovery and Resilience Plan and an improvement of public finances.

In 2020, a sharp drop in energy prices and subdued aggregate demand pushed headline inflation down to 2.3% from 3.9% in 2019. In 2021, some inflationary pressures are expected to come from higher oil prices and the liberalisation of the retail electricity market on 1 January, which is set to increase energy prices in the first part of the year. The annual average rate of inflation is forecast to slightly increase to 2.6% in 2021 and to decline somewhat to 2.4 % in 2022.

2.2 The Western Balkan Economies: Serbia, North Macedonia, Montenegro, Bosnia and Herzegovina, Albania and Kosovo

The third group of countries constitutes the so called "weak link" of the SE European economies. Historically divergent and financially vulnerable, they all aspire to join at some point the EU, while trying to surpass their bilateral conflicting past. The main challenges the six countries have to deal with are the existence of a macroeconomic stability necessary for sustained income growth, competitiveness, strong labor market and public finances in order to restart their EU convergence process that was postponed since the 2008 global financial and economic crisis. The adoption of structural reforms should be multidimensional: investment support through the business environment improvement, deepen global integration, more efficient public services, etc. Another important aspect is the challenge of rising transit migration through the region and how the EU and the corresponding governments will handle this, as this could disrupt regional trade, labor markets and remittances.

Serbia

After a robust growth of 4.2% in 2019, the COVID-19 pandemic caused a recession of 1% in 2020. This is a significantly better result than what was previously projected (a drop of 3%). Services' sectors were hit most by the pandemic-related events (down 1.5% y-o-y), while value added in industry remained flat in real terms, and the agriculture sector grew by 4.9%. On the expenditure side, both investment and consumption had a negative contribution to growth in 2020 (-1.1% and -0.7%, respectively), while net exports had a positive contribution to growth (0.8%).

A large fiscal stimulus program, introduced by the government, close to 13% of GDP helped keep the recession mild. It comprised tax deferrals and increased expenditures of around 8% of GDP and guarantees in the amount of 4.8% of GDP. As the largest part of the package (7.4% of GDP) went to businesses, it helped to avoid a major loss in employment. In fact, registered employment increased by 1.9% compared to 2019. The Q3 unemployment rate, as measured by the Labor Force Survey, stood at 9% in 2020, slightly lower than 2019. The wage subsidy and cash support to citizens also helped avert a spike in poverty, although at a significant fiscal cost. Due to the support package, limited labor market impacts, and growth in agriculture, poverty (income under $5.5/day in revised 2011 PPP) is estimated to have remained stagnant from 17.3% in 2019 to 17.4% in 2020.

The fiscal deficit increased significantly in 2020 and reached an estimated 8.1% of GDP. This increase is primarily the result of the large fiscal stimulus program. Public debt is estimated at 58.2% of GDP by end-2020. Inflation by year-end reached 1.3% y-o-y; however, food prices increased by 2.1%. The dinar remained broadly stable against the euro, supported by significant interventions by the National Bank of Serbia (NBS) on the foreign exchange market (NBS sold reserves worth €1.5 billion in 2020). The banking sector's performance remains robust despite two rounds of debt moratoria introduced in 2020 as part of the COVID-19 response measures. Non-Performing Loans (NPLs) stood at 3.5% as of November 2020. On the external side, the CAD decreased significantly – from 6.9% of GDP in 2019 to 4.3% in 2020.

Recovery from the COVID-19 related recession is expected to start in 2021. Growth will be supported by a recently announced new package of measures to support citizens and the economy worth 5.1% of GDP. As a result, Serbia's economy is expected to rebound by 5% in 2021, based on the World Bank's estimates. Over the medium term, growth is expected to be around 4%. Growth will be driven by consumption and investment will recover only slowly, which may slow down the impact of growth on labor markets (both employment and wages). This medium-term outlook crucially depends on international developments (including the control of COVID-19), the pace of structural reforms and political developments.

Table 2. 9 **Macroeconomic Performance of Serbia**

Serbia	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	2,0	-0,7	2,9	-1,6	1,8	3,3	2,1	4,5	4,2	-1,0	5,0
GDP at current prices (billion LC)	3614,8	3812,7	4124,1	4163,4	4315,0	4528,2	4760,7	5072,9	5417,7	5463,5	5871,7
GDP at current prices (billion USD)	49,3	43,3	48,4	47,1	39,7	40,7	44,2	50,6	51,5	53,0	60,4
GDP per capita at current prices (LC)	499517,1	529430,6	575458,0	583784,4	608144,8	641539,5	678077,6	726510,1	777988,0	787718,3	849969,5
GDP per capita at current prices (USD)	6814,7	6016,8	6757,5	6603,5	5589,0	5765,2	6292,5	7252,4	7391,8	7635,6	8748,3
Total investment (% of GDP)	18,4	19,2	17,3	16,7	18,7	18,1	19,6	22,7	25,1	23,2	23,9
Inflation (annual average)	11,1	7,3	7,7	2,1	1,4	1,1	3,1	2,0	1,9	1,7	2,2
Volume of imports of goods and services (%)	6,8	1,0	2,7	3,2	7,9	10,5	10,6	10,2	11,4	-3,9	6,6
Volume of exports of goods and services (%)	3,6	-0,1	17,9	4,2	10,8	11,3	9,8	7,9	10,1	-4,6	6,5
Unemployment rate (annual average)	23,6	24,6	23,0	19,9	18,2	15,9	14,1	13,3	10,9	13,3	13,0
Population (million)	7,2	7,2	7,2	7,1	7,1	7,1	7,0	7,0	7,0	6,9	6,9
General government gross debt (% of GDP)	43,9	54,4	57,5	67,5	71,2	68,8	58,6	54,4	52,8	58,4	59,0
Current account balance (% of GDP)	-8,1	-10,8	-5,7	-5,6	-3,5	-2,9	-5,2	-4,8	-6,9	-4,3	-5,7

Source: IMF World Economic Outlook (April 2021)

Immediate focus is needed on measures to improve the business environment and governance in order to lower the cost of doing business and ensure security and safety, as well as efforts to improve the quality of infrastructure. Regarding the medium- to long-term challenges the focus should be on demography and climate change. Firstly, an aging and shrinking population will leave Serbia with a smaller available labor force. Labor shortages combined with skills mismatches could significantly hurt the competitiveness of the Serbian economy. Secondly, the impact of climate change – including more frequent and severe droughts and floods – will hit agriculture and food production hard and will make the cost of infrastructure maintenance much higher.

The pace of labor market recovery will be critical for resumed poverty reduction. The new package is expected to support citizens and economic recovery, though poor and vulnerable households, who tend to depend more on self-employment and less secure jobs, may take longer to regain their income level. Poverty is projected to slowly decline to 16.8% in 2021.

In the medium term, regional disputes and slow progress with the EU accession process could affect investment sentiment and therefore delay investment projects in infrastructure and other sectors. Labor market challenges limit the scope for robust welfare improvements and could be exacerbated by a significant brain-drain.

North Macedonia

According to the World Bank, North Macedonia's real GDP declined by 4.5% in 2020; less than earlier projected as the recession sharply eased in Q4 2020. Private consumption, the main driver of growth in the past, experienced a sharp decline of 5.6% y-o-y as a result of containment measures. Investment also declined by more than 10%, even though it shortly rebounded in Q3 2020. Government induced consumption that increased by almost 10% helped partly alleviate declining domestic demand. External demand also plummeted, reflected in a 10.9% y-o-y decline of exports. The accompanying decline in imports alleviated the pressure on the current account deficit which is expected to remain largely unchanged compared to 2019. On the production side, agriculture, ICT and real estate activities were only sectors growing in 2020.

Government support helped cushion the crisis impact on the labor market by supporting over 130,000 jobs through wage subsidies in April 2020, declining to 60,000 towards the year-end as the economy slowly recovered. The unemployment rate remained largely unchanged, but this was partly a result of people dropping out of the labor market. The banking sector liquidity ratio of over 23% in Q3 2020 remained adequate, helped by the central bank measures. Credit continued growing at 4.7% y-o-y by end-2020, on account of both household and firm credits supported by strong deposit growth and crisis-support programs.

Non-performing loans declined to 3.3%, given the allowed suspension on credit reclassification requirements until December. However, an upward correction is expected in 2021 as this measure ended. The capital adequacy ratio stood at 16.9% in Q3 2020, double the mandatory level. Inflation remained low at 1.2% y-o-y in 2020, reflecting subdued output and despite rising food prices in the second half of 2020. The fiscal deficit tripled to 8.9% of GDP in 2020. The drop in VAT and excise revenues amounted to 0.9% of GDP and was cushioned somewhat by an increase in social contributions. Spending increased by 4.4% of GDP, as health expenditures and subsidy schemes, aimed at employment retention, surged. Spending on wages and pensions also increased as a result of previous policy changes, while capital spending declined. Public and publicly guaranteed debt increased to 60.2% of GDP as the government ramped up borrowing to finance the soaring deficit and repay maturing obligations.

Based on the World Bank's estimates, the economic growth is expected to rebound to 3.6% in 2021. This scenario assumes accelerated vaccinations by mid-2021, no further lockdowns, and increased external demand. In this scenario of a gradual recovery, after a protracted recession in Q1 2021, a rebound is expected thereafter, as restored consumer and investor confidence pushes up personal consumption, private investment, and exports. The fiscal deficit is planned at 4.9% but given the extended government support to firms and households in early 2021 of an additional 1.4% of GDP, the actual deficit will likely be higher.

Setting public finances back on a sustainable path will be needed over the medium term, as public and publicly guaranteed debt surpasses 64% of GDP in 2021. Targeting a primary balance over the medium term would be needed to stem further public debt growth and not crowd out productive spending. This is even more important in the eventuality that international financing costs rise. Boosting revenues through cutting back on exemptions and strengthening compliance are priorities along with a gradual state withdrawal from the corporate sector. Bringing people back to the labor market, as well as education and governance reforms could help boost potential growth. Poverty is projected to resume its decline as growth gradually recovers in 2021.

Table 2. 10 **Macroeconomic Performance of North Macedonia**

North Macedonia	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	2,3	-0,5	2,9	3,6	3,9	2,8	1,1	2,9	3,2	-4,5	3,8
GDP at current prices (billion LC)	464,2	466,7	501,9	527,6	559,0	594,8	618,1	660,9	689,4	664,0	699,6
GDP at current prices (billion USD)	10,5	9,8	10,8	11,4	10,1	10,7	11,3	12,7	12,6	12,3	13,8
GDP per capita at current prices (LC)	225355,5	226302,8	242956,0	254996,2	269859,5	286827,1	297839,2	318168,0	332052,2	319810,9	336943,2
GDP per capita at current prices (USD)	5097,3	4728,4	5239,6	5498,6	4860,4	5153,0	5462,4	6111,2	6044,4	5918,1	6656,7
Inflation (annual average)	3,9	3,3	2,8	-0,3	-0,3	-0,2	1,4	1,5	0,8	1,2	2,0
Volume of imports of goods and services (%)	8,0	8,2	2,2	14,1	9,9	11,1	5,2	10,7	8,9	-10,5	6,3
Volume of exports of goods and services (%)	16,1	2,0	6,1	16,5	8,5	9,1	8,3	12,8	7,2	-10,9	8,6
Unemployment rate (annual average)	31,4	31,0	29,0	28,0	26,1	23,8	22,4	20,7	17,3	16,4	16,3
Population (million)	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1	2,1
General government gross debt (% of GDP)	27,7	33,7	34,0	38,0	38,1	39,8	39,4	40,4	40,6	51,3	53,8
Current account balance (% of GDP)	-2,5	-3,2	-1,6	-0,5	-2,0	-2,9	-1,0	-0,1	-3,3	-3,5	-3,2

Source: IMF World Economic Outlook (April 2021)

Montenegro

As a small, open, and heavily tourism-dependent economy, Montenegro was hit hard by COVID-19, affirming its vulnerabilities to strong boom-bust cycles. Over the five years prior to the crisis, economic growth averaged 4%, driven by large public investments and consumption. Over two-thirds of Montenegro's jobs are in services, which account for over 70% of value added. The external imbalances are structurally high and averaged 15% of GDP over 2015-2019, largely financed by net FDI and external debt. Due to weaker adherence to fiscal plans and debt-financed highway construction, public debt has doubled since independence. Montenegro aspires to join the EU, but significant rule of law challenges slow down progress and reflect a key development constraint. The crisis has wiped out recent economic and social gains from the period of strong growth and exacerbated Montenegro's vulnerabilities.These include: the lack of fiscal space, small production base and low diversification of the economy, business environment weaknesses, and income and social inequalities.

These vulnerabilities translate into significant reversals of progress in creating jobs, raising income, and reducing poverty. Montenegro ranks third in the number of infections per million inhabitants and records among the highest death rates per capita from COVID-19 in the world. The pace of recovery will depend on when the pandemic is contained and the pace of immunization, which is currently slow. In 2020, the new government committed to accelerating reforms, strengthening the rule of law, and fighting corruption. These, coupled with strong fiscal and debt management and independent and accountable state institutions, would enable more inclusive, private sector-led growth and efficient service delivery to citizens. In 2020, general government revenues declined by 13% y-o-y, strongly driven by declines in VAT (-24%). General government spending went up by 4.6%, partly due to support measures, while capital spending fell by 25%. In December, Montenegro placed a 7-year €750 million Eurobond, with an interest rate of 2.875% to pre-finance maturing debt and 2021 fiscal deficit, based on the World Bank's data.The financial sector was resilient in 2020: outstanding loans (including those in moratoria) were up by 3%, while deposits fell by 3%, driven by declining household deposits. Yet, new lending was down by 26% and bank profits declined by over 50%. As exports plunged and imports showed more resilience, the current account deficit widened to 26% of GDP.

The blurred outlook due to the pandemic developments and vaccine rollouts is further dimmed by lack of clarity on the government's medium-term plans. Due to a low base and assuming tourism recovers to 55% of 2019 levels, Montenegro's economy is expected to rebound in 2021 with an estimated GDP growth of 7.1%, based on the World Bank's estimates. The total output loss is, however, projected to be fully recovered only in 2023 when the economy is expected to grow 3.5%. External imbalances will remain elevated in 2021, but the finalization of the import-dependent motorway section and stronger exports led by the tourism recovery are projected to reduce the current account deficit to 13% and 10% of GDP in 2022 and 2023, respectively. After peaking at 105% of GDP in 2020, public debt is estimated to return to pre-crisis levels by 2023. However, the actual debt reduction trajectory might be steeper or flatter, depending on the government's medium-term budgetary plans which are still unknown, as it delayed the 2021 budget adoption. However, implementation of sound and credible fiscal policies is an imperative for debt sustainability.

The outlook on employment is also highly uncertain and depends on the recovery of labor-intensive sectors. The speed of recovery of low-skill jobs will partly determine how fast poor and vulnerable households can return to pre-crisis income levels. The poverty rate is projected to decline to 17.9% in 2021. The current crisis has made the longstanding policy priority of improving economic resilience more urgent than ever. In order to accelerate recovery and sustain inclusive growth and poverty reduction, "Montenegro must keep macroeconomic stability, ensure inclusive and efficient provision of public services, carefully manage its natural resources and strengthen the independence and capacities of its institutions", says the World Bank.

Table 2. 11 **Macroeconomic Performance of Montenegro**

Montenegro	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	3,2	-2,7	3,5	1,8	3,4	2,9	4,7	5,1	4,1	-15,2	9,0
GDP at current prices (billion LC)	3,3	3,2	3,4	3,5	3,7	4,0	4,3	4,7	5,0	4,2	4,6
GDP at current prices (billion USD)	4,5	4,1	4,5	4,6	4,1	4,4	4,9	5,5	5,5	4,8	5,7
GDP per capita at current prices (LC)	5264,9	5126,5	5412,9	5561,1	5873,5	6354,2	6907,3	7494,6	7951,7	6736,8	7439,2
GDP per capita at current prices (USD)	7327,3	6590,6	7189,0	7389,9	6517,4	7031,5	7800,3	8854,8	8902,7	7688,6	9064,2
Total investment (% of GDP)	19,3	20,6	19,6	20,2	20,1	26,1	30,2	31,9	31,9	25,5	23,3
Inflation (annual average)	3,5	4,1	2,2	-0,7	1,5	-0,3	2,4	2,6	0,4	-0,2	0,4

Table 2. 11 **Macroeconomic Performance of Montenegro**

Volume of imports of goods and services (%)	3,0	1,8	-3,8	1,1	9,3	13,1	8,2	9,7	2,1	-19,7	14,0
Volume of exports of goods and services (%)	6,6	-0,9	0,1	-1,2	9,3	4,4	7,3	11,3	7,3	-48,5	57,5
Unemployment rate (annual average)											
Population (million)	0,6	0,6	0,6	0,6	0,6	0,6	0,6	0,6	0,6	0,6	0,6
General government gross debt (% of GDP)	48,6	56,9	58,7	63,4	68,8	66,4	66,2	71,9	78,7	108,8	94,6
Current account balance (% of GDP)	-14,8	-15,3	-11,4	-12,4	-11,0	-16,2	-16,1	-17,0	-15,0	-25,9	-18,7

Source: IMF World Economic Outlook (April 2021)

Bosnia and Herzegovina

Based on the World Bank's data, Bosnia's real GDP growth is projected at -4.0% in 2020 due to a slowdown in most productive sectors, a weaker external environment and high political uncertainty. In 2020, growth was positive in Q1 but after the introduction of a lockdown and containment measures in Q2, the economy faced a sudden stop as domestic and external demand dropped. By Q4 2020, the country's economic activity had somewhat improved, but growth remained in negative territory.

Unemployment has recently worsened. According to official estimates, the number of people in paid employment decreased approximately 1% y-o-y in November 2020, while the number of unemployed increased by about 3% in the same period. Deeper labour market effects have been prevented by wage subsidy programs in both entities and other policy measures targeting affected economic sectors aimed to safeguard potential job losses. As the economy has fallen into recession and with low oil prices deflation has returned. In December, the consumer price index was down 1.6% y-o-y. In 2020, a fiscal deficit of 5.5% of GDP is expected, down from a surplus of 1.9% in 2019. In 2020, revenues fell mainly due to the slump in tax revenue collection, while expenditures rose mainly as a result of higher spending on public wages, goods and services and social benefits. The current account deficit is estimated to have worsened slightly in 2020 due to a drop in the services balance and remittances. Total public debt, consisting largely of concessional debt, has increased and is estimated at 40.6% of GDP, while the total external debt is estimated at 72% of GDP.

Even during the pandemic, the financial sector has been broadly stable. On average, banks are sufficiently capitalized and liquid, but their profitability is eroding. The latest available poverty data using the national poverty line is for 2015 and the poverty rate was estimated at 16 percent, very close to the 15 percent estimated for 2011.The slowdown in the economy and the consequent loss of people's employment and earnings have negatively affected household welfare in 2020. Estimates show that many of those who may have been affected were not covered by social protection programs before the crisis. The outlook is marked by the implementation of measures to combat the pandemic. Authorities are currently focused on securing vaccines. As the pandemic subsides the Socio-Economic Program is expected to gain needed attention, mainly through the return of announced investments in energy and infrastructure. Consumption will continue to drive growth, resulting in strong growth of imports. Remittances will recover in the medium term and, together with progress on re-forms, will underpin a gradual pickup in consumption and finance a significant part of the trade deficit.

Table 2. 12 **Macroeconomic Performance of Bosnia and Herzegovina**

Bosnia and Herzegovina	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	0,9	-0,7	2,4	1,1	3,1	3,1	3,2	3,7	2,8	-5,5	3,5
GDP at current prices (billion LC)	26,2	26,2	26,7	27,3	28,6	29,9	31,4	33,4	35,3	33,2	34,8
GDP at current prices billion USD)	18,6	17,2	18,2	18,5	16,2	16,9	18,1	20,2	20,2	19,4	22,0
GDP per capita at current prices (LC)	7161,1	7265,8	7550,3	7841,6	8336,5	8830,2	9357,7	10064,4	10692,4	10132,9	10650,5
GDP per capita at current prices (USD)	5089,9	4773,2	5125,6	5319,3	4727,3	4994,1	5392,4	6073,9	6120,2	5913,0	6727,8
Total investment (% of GDP)	18,3	18,3	17,2	18,4	17,9	18,9	21,1	21,1	21,6	21,9	21,5
Inflation (annual average)	4,0	2,1	-0,1	-0,9	-1,0	-1,6	0,8	1,4	0,6	-0,6	1,2
Volume of imports of goods and services (%)	3,2	0,4	0,1	7,6	1,7	7,3	8,2	3,3	1,3	-10,9	9,4
Volume of exports of goods and services (%)	4,8	-0,2	7,9	4,2	9,8	9,4	12,4	6,3	0,5	-8,7	6,6
Unemployment rate (annual average)	27,6	28,0	27,5	27,5	27,7	25,4	20,5	18,4	15,7	19,0	17,5
Population (million)	3,7	3,6	3,5	3,5	3,4	3,4	3,4	3,3	3,3	3,3	3,3
General government gross debt (% of GDP)	39,6	42,2	42,5	45,9	45,5	44,1	39,2	34,3	32,4	38,3	38,6
Current account balance (% of GDP)	-9,5	-8,6	-5,3	-7,4	-5,1	-4,8	-4,8	-3,4	-3,1	-3,5	-4,9

Source: IMF World Economic Outlook (April 2021)

Monetary policy anchored to the Euro will continue to support local currency stability. Safeguarding the banking sector will continue to be important in particular as the full impact of moratoria is yet to be assessed. Authorities have adopted budgets and secured funds to ensure necessary liquidity through credit lines via entity development banks to support affected businesses.

As Bosnia and Herzegovina does not have access to international markets, support from International Financial Institutions (IFIs) will be critical. As revenues recover Bosnia's fiscal deficit will return to surplus over the medium term. A stronger push on the capital investment program will need to remain a high priority for the authorities' economic programs.

Planned investments in energy, infrastructure, and tourism will also support job creation in those sectors after the crisis.

As the pandemic is tamed and the economy gradually recovers in 2021, improvements in labor market participation and employment will remain key for growth to translate into poverty reduction. There are several risks to the outlook but the main risk is a prolonged pandemic which could lead to lower growth rates in 2021 than projected. In addition, the challenging political environment will affect the implementation of the adopted socio-economic program. The main external risk for Bosnia and Herzegovina remains slow growth in the EU and political tensions in the region.

Albania

According to the World Bank, Albania's real GDP grew by 3.3% during 2015-2019, with the country achieving significant reform progress while aspiring to EU membership. A few large renewable energy projects and expansion in tourism and garments' manufacturing exports drove GDP and employment growth. However, productivity has stagnated below that of peer countries, and wage pressures could reduce competitiveness. Small and Medium Enterprises (SMEs) represent more than 90% of private firms and rely on low-skilled, low-wage labor. Limited access to finance, burdensome logistics and poor market integration discourage private investment, while scarce public revenues limit public infrastructure and human capital investment.

Growth halted in 2019, as a 6.4-magnitude earthquake with an epicentre 16 km west-southwest of Mamurras in November 2019 further exposed the country's low buffers. Fiscal consolidation was put on hold and external vulnerabilities reemerged. The pandemic hit Albania's key sectors of tourism and manufacturing through the recession in the EU, supply chain disruptions, travel limitations and social distancing measures.

Based on the World Bank's estimates, Albania's real GDP is projected to decline by 4.7% in 2020 due largely to a slowdown in tourism, though smaller than initially projected as domestic tourism demand partially compensated for the drop in foreign visits. Public support packages for reconstruction and to mitigate the crisis had a small estimated success in preventing an increase in poverty and had a significant fiscal cost. Recently, introduced tax incentives further stress already declining revenues. Delayed global vaccine rollout could cause long-lasting travel restrictions and could prevent a recovery of the country's services and manufacturing, worsening the performance of businesses and delaying the full recovery in employment. The normalization of the global economy will have a significant impact on the shape of the recovery.

Tourism and travel are likely to remain limited until global vaccination rollout is completed. In this scenario, Albania's real GDP is forecasted to grow by 4.4% in 2021, based on World Bank estimates, as exports, consumption and investment partially rebound. The services sector, led by tourism, and construction are expected to be key drivers of the recovery, in part thanks to reconstruction investment, following evidence from similar disasters in developing economies.

Poverty in Albania is expected to decline in line with anticipated recovery by about 2%. In the years following, private consumption will play an increasingly important role in growth, supported by reconstruction efforts. Private investment will contribute to growth, provided that the government continues to implement business climate reforms. Beyond 2021, government spending will likely be constrained by limited fiscal space. The fiscal situation could deteriorate in a downside growth scenario and in the absence of expanded revenue collection. In this case, the government may need to further reduce capital spending to keep the debt to GDP ratio from rising.

According to the World Bank, Albania's current account deficit is expected to narrow to 8.8% of GDP in 2021 and further decline to 6.5% in line with the pre-crisis trends, driven by projected improvements in the trade balance. Service exports, including tourism and fast-expanding business-process operations, should narrow the trade deficit over the medium term. Import growth will be high at 13% in 2021, as infrastructure investment speeds up.

With economic activity picking up, revenues are projected to recover to 27.6% of GDP by 2022-2025. Albania's public debt is projected to only marginally decrease to 79.5% of GDP in 2021. The employment outlook is largely dependent on the recovery of the services sectors and reconstruction, where jobs are mostly low pay and vulnerable to economic uncertainty.

Table 2. 13 **Macroeconomic Performance of Albania**

Albania	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	2,5	1,4	1,0	1,8	2,2	3,3	3,8	4,1	2,2	-3,5	5,0
GDP at current prices (billion LC)	1300,6	1332,8	1350,1	1395,3	1434,3	1472,5	1550,6	1635,7	1678,4	1642,6	1757,5
GDP at current prices (billion USD)	12,9	12,3	12,8	13,2	11,4	11,9	13,1	15,1	15,3	15,1	17,1
GDP per capita at current prices (LC)	447689,1	459526,5	466324,6	482954,1	497901,6	511970,6	539644,6	570656,0	584877,0	573296,3	614385,0
GDP per capita at current prices (USD)	4439,9	4248,9	4415,6	4584,9	3953,6	4124,4	4542,8	5284,4	5323,2	5286,7	5991,1
Total investment (% of GDP)	33,5	29,8	27,5	27,3	26,2	25,5	24,7	24,3	22,8	22,8	23,8
Inflation (annual average)	3,4	2,0	1,9	1,6	1,9	1,3	2,0	2,0	1,4	1,6	2,0
Volume of imports of goods and services (%)	3,6	-7,6	-0,6	5,4	0,1	8,3	6,0	5,8	5,0	-21,4	10,5
Volume of exports of goods and services (%)	1,0	-0,4	8,3	3,3	5,3	10,4	10,1	3,5	1,8	-29,0	16,4
Unemployment rate(annual average)	14,0	13,4	15,9	17,5	17,1	15,2	13,7	12,3	11,5	12,5	14,0
Population (million)	2,9	2,9	2,9	2,9	2,9	2,9	2,9	2,9	2,9	2,9	2,9
General government gross debt (% of GDP)	59,4	62,1	70,4	72,0	73,7	73,3	71,9	69,5	67,8	76,0	75,4
Current account balance (% of GDP)	-12,9	-10,2	-9,3	-10,8	-8,6	-7,6	-7,5	-6,8	-8,0	-9,6	-8,7

Source: IMF World Economic Outlook (April 2021)

Kosovo

Based on the World Bank's data, Kosovo's real GDP growth averaged 3.6% over 2009-2019 and, before the pandemic, was expected to exceed 4% in the medium term. Private investment added to growth in recent years, but was mostly concentrated in trade and construction industries, with limited productivity spillovers.

Likewise, robust growth did not translate into more jobs as the employment rate remained almost constant between 2017 and 2019. In 2019, 21% of the population still lived with under $5.5 per person per day (in 2011 PPP), and this share is expected to increase in 2020 by 4%-5%. Poor education and health outcomes limit the contribution of human capital to inclusive growth and the pandemic likely widened this gap. As a largely service and consumption-based economy, Kosovo was particularly vulnerable to the COVID-19 shock.

To support the recovery in 2021, the country's government should strengthen compliance with pandemic preventive measures, increase treatment capacity and effectiveness, while reducing citizens' out-of-pocket costs, and boost vaccination, according to the World Bank. Targeting of social protection and private sector support measures should be improved and implementation of public projects with secured financing accelerated. To support a resilient recovery in the medium term, public spending effectiveness and the regulatory environment should be enhanced. Investment in human capital should be prioritized. In 2020, Kosovo's economic activity is estimated to contract by 6.9%, based on the World Bank's estimates, driven by a plunge in exports - principally because of a 51% drop of diaspora travel services - and investment. Consumption contributed modestly, with higher government offsetting lower private consumption. Fiscal stimulus combined with increased remittances and goods exports cushioned the contraction. Consumer price inflation decelerated in 2020 to 0.2% because of weak domestic demand and declining import prices. Formal employment weathered the impact of the downturn, but compensation and working hours were reduced. Registered unemployment increased, most likely from job losses in the informal economy. Overall, unemployment remains high at 25% of the labor force (46.9% of youth) in Q3 2020. Projections suggest a poverty increase of 4%-5% in 2020 (70-90 thousand new poor). The expected return to growth in 2021 should modestly reduce poverty as the services sector recovers.

Despite a 28.4% reduction in public investment, the budget deficit closed 2020 at 7.6% of GDP, due to lower public revenues against the contraction. Current spending increased by 18.6%, driven by pandemic-related spending of an estimated 4.4% of GDP. The deficit was financed primarily through domestic and external debt and liquidation receipts.The drop in imports and a rise in secondary income almost compensated the plunge in exports during 2020. As a result, the current account deficit (CAD) deteriorated marginally from 5.5% to 5.7% of GDP. CAD was primarily financed by net FDI inflows and other international debt-driven investment flows.

Bank deposits and bank credit increased by 11.5% and 7.1%, respectively. New loans increased only by 1.8%, reflecting restructuring activity throughout the year. Capital adequacy is above regulatory requirements, while NPLs increased by 0.7%. Forbearance measures by the Central Bank cushioned the impact of the pandemic on the financial sector.

Based on the World Bank's estimates, Kosovo's real GDP is projected to reach 4% in 2021. The recovery is expected to be gradual. Economic activity will reach pre-pandemic levels only in 2022, mainly driven by a rise in exports and consumption. Growth in goods exports should continue to be strong in the medium term, as base metal prices are expected to rise. Service exports should also recover driven by a recovery in diaspora-related tourism exports, as international travel restrictions are relaxed, and vaccination accelerates in Europe. Economic growth is projected to remain over 4% in the medium term, but downside risks to the outlook are high. The projected outlook rests on the assumption of relaxed international mobility between Europe and Kosovo, no further strict local containment measures and a recovery in Euro Area growth. There is also potential for higher growth, including through faster implementation of IFI-financed public investment.

Fiscal deficit will remain elevated in 2021 projected at 5.1% of GDP, driven by fiscal stimulus measures and the disruption in the growth trajectory induced by the pandemic. Revenues are expected to recover as growth picks up. Fiscal stimulus aimed at supporting businesses and livelihoods should be fully executed in 2021, at about 3.2% of GDP.

According to the World Bank, the CAD should remain at 5.7% of GDP in 2021 and gradually improve over the medium term. Goods' exports should increase gradually, while imports also increase on the back of higher aggregate demand. The size of the CAD will be deter-mined by the pace of remittance growth and recovery of diaspora-related tourism exports. The pandemic has intensified the developmental gaps, hence progress on structural reforms, including improvements in the design and targeting of social protection spending and regulatory environment for businesses is vital in reversing the adverse economic and social impact of the pandemic and building resilience against future negative shocks.

Table 2. 14 **Macroeconomic Performance of Kosovo**

Kosovo	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	4,4	2,8	3,4	1,2	4,1	4,1	4,2	3,8	4,9	-6,0	4,5
GDP at current prices (billion LC)	4,8	5,1	5,3	5,6	5,8	6,1	6,4	6,7	7,1	6,8	7,1
GDP at current prices (billion USD)	6,7	6,5	7,1	7,4	6,4	6,7	7,2	7,9	8,0	7,8	8,8
GDP per capita at current prices (LC)	2704,7	2786,3	2925,7	3084,6	3278,1	3403,4	3566,2	3751,7	3946,5	3776,2	3930,2
GDP per capita at current prices (USD)	3764,2	3582,0	3885,7	4098,9	3637,4	3766,2	4027,3	4432,6	4418,5	4309,8	4855,7
Inflation (annual average)	7,3	2,5	1,8	0,4	-0,5	0,3	1,5	1,1	2,7	0,2	0,3
Volume of imports of goods and services (%)	8,6	-16,3	-1,2	7,2	-14,7	6,1	7,7	16,4	-3,3	-1,8	12,6
Volume of exports of goods and services (%)	31,2	-1,7	-17,1	-7,2	-25,4	2,1	21,1	16,5	0,4	-25,9	21,1
Unemployment rate (annual average)	n/a	30,9	30,0	35,3	32,9	27,5	30,5	29,6	25,7	25,6	n/a
Population (million)	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8	1,8
General government gross debt (% of GDP)	5,3	8,1	9,0	10,7	13,1	14,4	16,2	17,0	17,6	24,4	28,5
Current account balance (% of GDP)	-12,7	-5,8	-3,4	-6,9	-8,6	-7,9	-5,4	-7,6	-5,5	-7,5	-6,4

Source: IMF World Economic Outlook (April 2021)

2.3 Turkey and Israel: The Economies of the East Med Countries

We have left for the end of this chapter the review for the economies of Turkey and Israel. Two important Mediterranean countries whose economies are markedly different from those of the other countries in SE Europe. To start with Turkey's economy is a lot larger and in size and roughly corresponds to the sum of the economies of all the other countries, EU member countries and WB6. This obviously affects energy infrastructure and energy market developments as we have already pointed out in our introduction.

Turkey's economy until recently had been performing well with a notable growth pattern and constant improvement of the standard of living. However, as it is explained further on, the Turkish lira devaluation in 2020-2021, following some unfortunate monetary policy moves, led to strong depreciation which impacted negatively the economy, a situation which exacerbated with the collapse of the tourist market in 2020 because of COVID-19. Despite of this outcome, the economy remains robust judging from its expansion in 2020 and anticipated growth in 2021.

Israel's economy is a different case all together. Despite the pandemic and geopolitical tensions in the region, the economy has managed to hold and develop. The country's finances have been strengthened by the improvement in the external balance of payments, following the growing consumption of domestically produced natural gas and the corresponding lessening of oil and coal imports and the continuing export of high tech products.

Turkey

Turkey was the only G20 country aside from China that recorded an economic expansion in 2020. However, this rapid recovery raised macroeconomic and financial stability risks. Unless addressed, these vulnerabilities will expose Turkey to heightened risk and continue to limit productivity, which has stagnated in recent years. Latest market turmoil, following the replacement of the Central Bank Governor[2], illustrates the importance of a sustained and credible focus on bringing inflation down to the target rate of 5% and bolstering the country's international reserves. Structural reforms in labor, product and financial markets, and to innovation systems can support productivity growth. Corporate sector vulnerabilities - further elevated by the pandemic and higher debt burden - present risks to banks. Developing local currency, long-term finance sources would alleviate existing imbalances in the financial system and contribute to economic growth.

The economic recovery in the second half of 2020 helped recover most of the jobs lost during the pandemic's first wave. However, jobs for informal, lower-skilled, female, and young workers remain well below their pre-pandemic levels. Furthermore, 2.6 million more individuals were out of the labor force in 2020. The poverty rate is projected to increase to 12.2% in 2020, which would mark the second successive year that poverty has increased in Turkey, from 8.5% in 2018. Based on the World Bank's data, Turkey's real GDP grew by 5.9% y-o-y in Q4 2020, completing a remarkable rebound in the second half and resulting in full-year growth of 1.8%, despite the economic fallout from the coronavirus pandemic. The recovery was driven by surging domestic demand, buoyed by credit in the second and third quarter. The authorities loosened monetary policy and delivered a stimulus program totaling 13% of GDP, most of which was supported via the banking sector in the form of partial credit guarantees and loan deferrals. Other fiscal support included social support payments to households, support for furloughed workers, tax deferrals, and other support for firms.

Growth from the implementation of the above policies came at the cost of rising prices and macro-financial vulnerabilities. Inflation trended upward, reaching 15.6% in February - the highest level in 18 months. The Turkish lira depreciated by 20% against the US dollar in 2020. From a surplus in 2019, the current account moved back into deficit ($36.7 billion or 5.1% of GDP) as tourism income evaporated, merchandise exports fell, and gold imports increased. After the central bank stepped in to finance as much as 80% of the current account deficit, foreign exchange reserves fell sharply, reaching unprecedented lows on a net basis. Deposit dollarization rose to 55%. Buoyant tax revenues resulted in a central government deficit of 3.4% of GDP in 2020, better than the planned deficit of 4.9% of GDP. Toward the end of 2020, a second wave of COVID-19 peaked, with cases reaching 30,000 a day in November. Following the re-imposition of containment measures (including masking, weekend curfews, and restaurant closures), new cases declined to around 10,000 a day by February 2021, following which, the government began easing restrictions again, based on a province-level risk assessment.

By late 2020, the authorities had also moved to address economic vulnerabilities, more than doubling interest rates between August and December, repealing exceptional regulations aimed at stimulating credit growth, and increasing transparency. This policy shift helped spur portfolio inflows, stabilize the lira, and strengthen market confidence. Credit growth decelerated sharply to near zero (13-week average) by February, and the banking sector reduced its net open foreign exchange position. Based on the World Bank's estimates, Turkey's economy is expected to grow by 5.0% in 2021 and by 4.5% in 2022 and 2023. Despite slow quarterly growth expected in 2021 - as

[2] https://www.aljazeera.com/economy/2021/5/25/turkey-removes-one-more-central-bank-deputy-governor

monetary policy remains tight and external demand weak - GDP in the second quarter will be higher than the year-earlier period when COVID-19 brought Turkey's economy to a near-standstill. These projections assume that cautious reopening continues and that there is no uncontrolled outbreak in Turkey or its major export markets, which could undermine growth.

Table 2. 15 **Macroeconomic Performance of Turkey**

Turkey	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	11,2	4,8	8,5	4,9	6,1	3,3	7,5	3,0	0,9	1,8	6,0
GDP at current prices (billion LC)	1404,9	1581,5	1823,4	2054,9	2350,9	2626,6	3133,7	3758,3	4320,2	5044,2	6025,5
GDP at current prices (billion USD)	838,5	880,1	957,5	938,5	864,1	869,3	858,9	779,6	760,9	719,5	794,5
GDP per capita at current prices (LC)	18801,6	20911,6	23783,4	26447,9	29856,6	32908,1	38778,2	45830,9	51953,5	59925,7	70735,9
GDP per capita at current prices (USD)	11221,4	11637,9	12489,0	12079,3	10973,6	10891,2	10628,9	9506,8	9150,9	8548,2	9327,3
Total investment (% of GDP)	31,0	28,1	29,6	29,0	28,2	28,0	30,7	29,3	24,8	31,5	29,9
Inflation (annual average)	6,5	8,9	7,5	8,9	7,7	7,8	11,1	16,3	15,2	12,3	13,6
Volume of imports of goods and services (%)	11,4	1,3	9,4	0,2	1,5	4,9	8,6	-8,4	-4,3	5,4	8,7
Volume of exports of goods and services (%)	8,7	13,6	6,3	6,9	1,5	-1,0	12,6	9,8	7,9	-18,0	20,2
Unemployment rate (annual average)	9,1	8,4	9,0	9,9	10,3	10,9	10,9	11,0	13,7	13,1	12,4
Population (million)	74,7	75,6	76,7	77,7	78,7	79,8	80,8	82,0	83,2	84,2	85,2
General government gross debt (% of GDP)	36,2	32,4	31,2	28,5	27,4	28,0	28,0	30,2	32,6	36,8	37,1
Current account balance (% of GDP)	-8,9	-5,4	-5,8	-4,1	-3,2	-3,1	-4,8	-2,8	0,9	-5,1	-3,4

Source: IMF World Economic Outlook (April 2021)

The lira's sharp depreciation in response to the replacement of the Central Bank Governor will impact inflation, according to banking sources. Average inflation is projected to increase in 2021 to 15.5%. The current account deficit is expected to narrow to 3.7% of GDP in 2021. The 2021 general government deficit is projected at 3.5% of GDP as the need for additional support to cushion the economic and social impact of the pandemic continues, before narrowing to 3.1% in 2022 and 2.6% in 2023 as temporary tax reductions and other government support is withdrawn. Regulatory forbearance (especially on non-performing loan definitions and capital adequacy ratio calculations) is expected to be phased out in mid-2021, after which there may be an increase in non-performing and distressed loans.

Strengthening bad loan resolution, insolvency, and out-of-court corporate debt restructuring frameworks with an effective corporate viability assessment will be critical to shield corporates and the banks from spillovers.Turkey's external risk profile is high due to its still-low level of international reserves and sizeable external financing needs. The country has limited space to manage exchange rate volatility in the event of new external shocks. The banking sector has adequate foreign exchange buffers, most of which form part of central bank international reserves.

According to the World Bank[3], simulation analysis suggests that poverty may have increased by as much as 2.1% in 2020 -equivalent to 1.6 million of new poor. The crisis pushed a similar number of people into poverty as the 2018/2019 recession. Had the government not acted swiftly to stem the social effects of COVID-19, the increase in poverty would have been three times greater. Turkey is projected to enter 2021 with the highest poverty rate since 2012. Successful poverty reduction will require ensuring that the recovery benefits informal and unskilled workers and other vulnerable groups through a policy mix of social transfers, inclusive job creation, and labor activation strategies.

Israel

The Israeli economy has recorded one of the best performances in the OECD country group in recent years. According to Santander's report[4], since the mid-2000s, Israeli real GDP growth has averaged 3.7%, mainly due to an increase in the working-age population and the participation rate. After reaching 3.4% of GDP in 2019, economic growth was abruptly halted due to the outbreak of the COVID-19 pandemic. A negative rate of -5.9% was recorded in 2020. According to the IMF's updated April 2021 forecast, real GDP growth is expected to pick up to 5.0% in 2021, depending on the post-pandemic recovery of the global economy. The exploitation of the Leviathan gas fields is, however, expected to stimulate growth. In the long term, the increase in the proportion of low-skilled Har (ultra-Orthodox Haredim) and Israeli Arab communities and of the working population (expected to fall from 25% to 40% by 2045) are potential obstacles to growth.

Building upon years of fiscal discipline and spending restraint, the Israeli economy continued to perform well in 2019. Private consumption increased 18.2% in Q4 2020, which was below the third quarter's 42.2% expansion, likely weighed on by the second lockdown early in the quarter. Government spending grew at the fastest rate on record, expanding 26.0% (Q3 2020: +8.5%, seasonally adjusted annualized rate). Meanwhile, fixed investment growth improved to 66.1% in Q4 2020, up from the 17.4% expansion in the prior quarter and driven by surging industrial investment. Based on data provided by Focus Economics , Israeli exports of goods and services fell 4.9% on a seasonally adjusted annualized rate basis in Q4 2020, which contrasted the third quarter's 67.6% expansion. Conversely, imports of goods and services bounced back, growing 88.5% in Q4 (Q3 2020: -1.3%, seasonally adjusted annualized rate basis). The reading was driven by surging car imports amid frontloading ahead of tax hikes at the start of 2021.

Israel has one of the highest living standards in the region. The average salary in Israel is similar to average salaries in Europe. However, 25% of Israelis live in poverty and inequality is relatively high, which explains the frequent protests and the pervasive current of simmering social unrest. Furthermore, households suffer from real estate prices and high costs of living (according to a study by the Taub Center, as cited by the aforementioned Santander's report, Israeli cost of living is 23% higher than the OECD average). According to the latest IMF estimates dated April 2021, the unemployment rate has risen due to the global crisis caused by the COVID-19 pandemic and reached 4.3% in 2020 and it is expected to remain at 5.0% in 2021. According to the IMF, Israel must promote its policies to ensure the social and economic integration of Arab and haredim minorities.

[3] https://pubdocs.worldbank.org/en/196091492011113987/mpo-tur.pdf
[4] https://santandertrade.com/en/portal/analyse-markets/israel/economic-political-outline

Table 2. 16 **Macroeconomic Performance of Israel**

Israel	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021e
Real GDP (% change)	4,7	2,5	4,3	3,9	2,3	3,8	3,6	3,5	3,4	-2,4	5,0
GDP at current prices (billion LC)	933,9	991,6	1056,8	1109,3	1166,5	1223,7	1269,4	1330,1	1406,7	1386,0	1458,7
GDP at current prices (billion USD)	261,0	257,2	292,7	310,0	300,1	318,6	352,7	370,5	394,7	402,6	446,7
GDP per capita at current prices (LC)	120305,9	125409,5	131186,4	135085,0	139258,1	143229,5	145750,8	149800,2	155424,1	150393,8	155441,1
GDP per capita at current prices (USD)	33622,6	32523,9	36332,1	37755,1	35828,2	37293,8	40491,3	41720,6	43603,0	43688,6	47602,1
Total investment (% of GDP)	21,0	21,3	20,1	20,6	19,9	21,1	21,5	21,7	21,4	21,9	21,6
Inflation (annual average)	3,5	1,7	1,5	0,5	-0,6	-0,5	0,2	0,8	0,8	-0,6	0,3
Volume of imports of goods and services (%)	11,2	2,1	1,3	2,1	0,2	10,4	4,8	6,4	4,1	-8,1	13,9
Volume of exports of goods and services (%)	8,2	-0,2	5,0	0,8	-2,4	0,8	3,5	6,4	4,0	0,6	7,8
Unemployment rate (annual average)	7,1	6,9	6,3	5,9	5,3	4,8	4,2	4,0	3,8	4,3	5,0
Population (million)	7,8	7,9	8,1	8,2	8,4	8,5	8,7	8,9	9,1	9,2	9,4
General government gross debt (% of GDP)	68,9	68,5	67,1	65,7	63,8	62,1	60,6	60,9	60,0	73,0	78,3
Current account balance (% of GDP)	1,6	0,5	2,9	4,2	5,4	3,5	2,9	2,7	3,1	4,9	4,1

Source: IMF World Economic Outlook (April 2021)

2.4 Discussion

The COVID-19 pandemic and related containment measures are taking a heavy toll on the global economy and will certainly affect the SEE economies, leading to much lower economic growth or even a recession. The region's economies will be affected at several levels, with tourism activity being declined in almost all SE European countries.

First, the containment measures will unequivocally affect domestic demand and supply, significantly decreasing economic activity. Supportive macroeconomic policies can partially aid the recovery of demand but cannot completely offset the economic consequences of enforced shutdowns and consumer reluctancy to spend. Second, the COVID-19 crisis has already curtailed global international travel demand and will certainly lead to a collapse in tourism ahead of the summer season.

Third, exports across the region will fall due to depressed demand, as well as disruptions in value chains. Although all economies will be affected, Romania and Serbia would likely bear the greatest cost, as their manufacturing sectors are more highly integrated into global supply chains and contribute the most to their economies in terms of value-added and employment. Fourth, a deceleration of both public and private investment can be expected, which will further inhibit economic growth. The contribution of Foreign Direct Investment (FDI) to the Western Balkan economies has been relatively sizeable over the last years, providing support for economic growth, job creation and technological progress.

Fifth, the Western Balkans and SE Europe in general rely heavily on the steady inflow of remittances, financing domestic demand and investment. In Kosovo, for instance, remittances account for 15% of overall GDP. In addition to the high volumes, the remittances are also quite concentrated in terms of source countries - Germany, Italy, Austria - further exacerbating the SEE economies' vulnerability to the crisis' impact in these economies. Remittances are likely to diminish due to travel restrictions and an increased unemployment, linked to the anticipated economic contraction in the EU.

The sustainability of growth is the top economic policy priority for the SEE countries and the driving force behind all reforms and stabilization policies adopted by the vast majority of the region's governments. The key policy priorities for the SEE region are the support of domestic demand, the confrontation of crisis legacies, such as the external shocks, and the improvement of business environment to enhance investment and long-term growth.

The regional economy is set to return to growth in H2 2021, recovering from the pandemic-induced downturn. The reopening of economies is set to buttress domestic and foreign demand; however, a sluggish labor market recovery, particularly as fiscal support measures are wound down, will limit household spending. Moreover, uncertainty regarding the pandemic clouds the outlook. The recovery in 2021 is conditional on a gradual resumption of normal activity in the region's economies and in those of their trading partners, which could be threatened by a resurgence of the pandemic.
A major hope and pillar of economic recovery in SE Europe, especially for its EU member countries, is expected to be the Recovery and Resilience Facility. More specifically, the EU member countries in SE Europe, through the submission of their national Recovery and Resilience Plans, will have access to the bloc's €750 billion recovery fund. The Recovery and Resilience Mechanism, a central element of the "Next Generation EU", was approved by European leaders in July 2020, as a main instrument for the EU's economic recovery from the crisis caused by the COVID-19 pandemic.

To sum up, all the SE European countries are now following the international developments, especially the ongoing coronavirus pandemic, and we have to observe the imminent repercussions they will have on their economies.

[5] https://www.focus-economics.com/countries/israel/news/gdp/economy-loses-steam-in-the-fourth-quarter-but-still-records-growth

References

(1) *IMF (2021), "World Economic Outlook Database (April 2021)", https://www.imf.org/en/Publications/WEO/weo-database/2021/April*

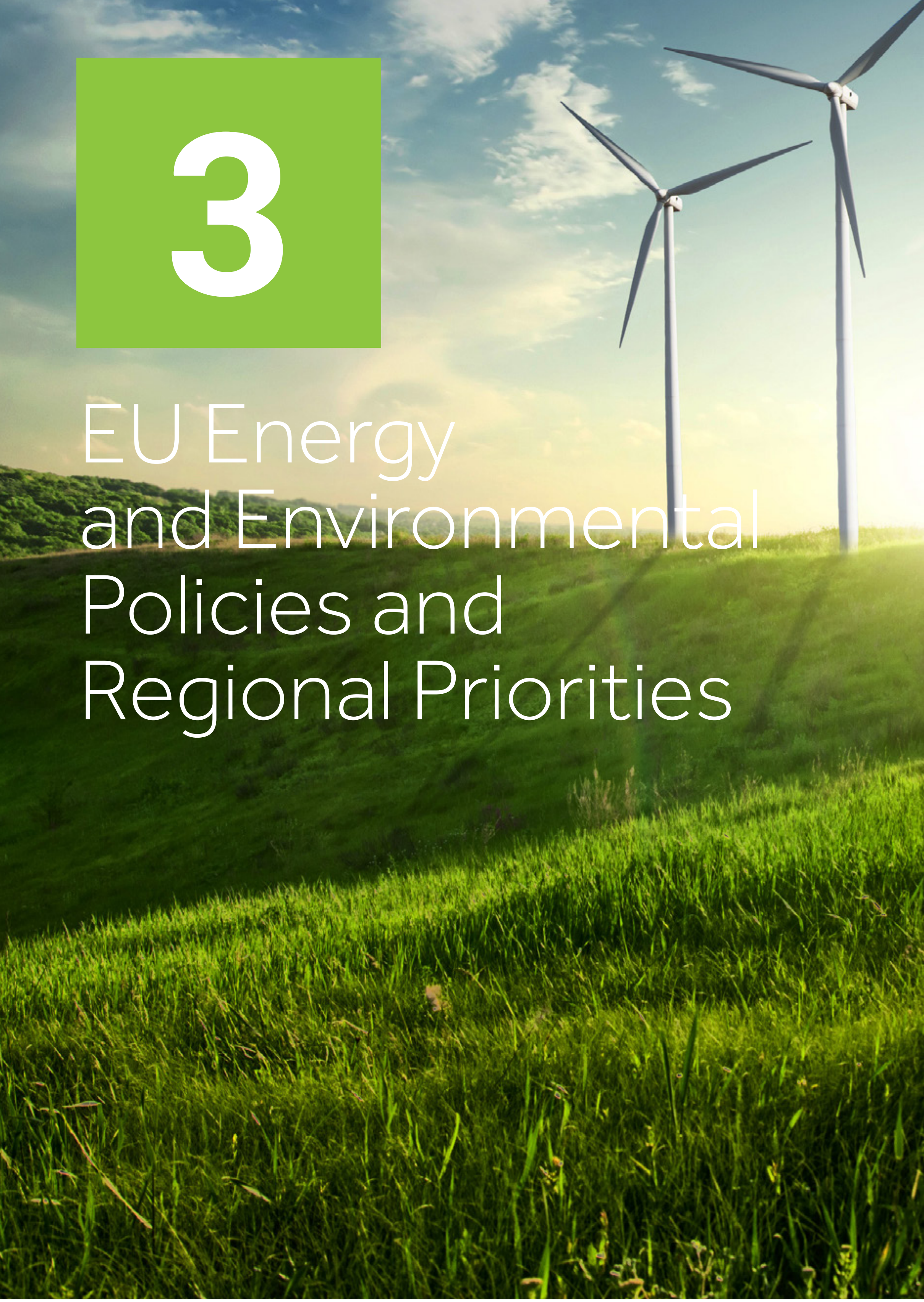
(2) *European Commission (2021), "European Economic Forecast – Winter 2021 (Interim)", Institutional Paper 144, https://ec.europa.eu/info/sites/info/files/economy-finance/ip144_en_1.pdf*

(3) *World Bank (2021), "Macro Poverty Outlook", https://pubdocs.worldbank.org/en/107191492012467509/mpo-eca.pdf*

(4) *Santander (2021), "Israel: Economic and Political Outline", https://santandertrade.com/en/portal/analyse-markets/israel/economic-political-outline*

(5) *Focus Economics (2021), "Israel GDP Q4 2020", https://www.focus-economics.com/countries/israel/news/gdp/economy-loses-steam-in-the-fourth-quarter-but-still-records-growth*

2



3

EU Energy and Environmental Policies and Regional Priorities

EU Energy and Environmental Policies and Regional Priorities

The main EU energy strategy is the **Energy Union Strategy**[1], published on February 25, 2015, as a key priority of the Juncker Commission (2014-2019). It aims to build an energy union that gives EU households and businesses secure, sustainable, competitive and affordable energy. Since the strategy's launch in 2015, the European Commission has published several packages of measures and regular progress reports, which monitor its implementation. The energy union builds five closely related and mutually reinforcing dimensions:

- **Security, solidarity and trust** - diversifying Europe's sources of energy and ensuring energy security through solidarity and cooperation between EU countries
- **A fully integrated internal energy market** - enabling the free flow of energy through the EU through adequate infrastructure and without technical or regulatory barriers
- **Energy efficiency** - improved energy efficiency will reduce dependence on energy imports, lower emissions, and drive jobs and growth
- **Climate action, decarbonising the economy** - the EU is committed to a quick ratification of the Paris Agreement and to retaining its leadership in the area of renewable energy
- **Research, innovation and competitiveness** - supporting breakthroughs in low-carbon and clean energy technologies by prioritising research and innovation to drive the energy transition and improve competitiveness.

The 2020 state of the energy union report[2] was published on October 14, 2020. The report looks at the energy union's contribution to EU's long-term climate goals and takes stock of the progress made in the five energy union dimensions. It also highlights how the NextGenerationEU recovery plan can support EU countries, through a number of EU funding programmes. The report is accompanied by a wide range of reports and annexes, including the individual assessments of the national climate and energy plans (NECPs), analysing the contribution each country is committed to make to the EU 2030 energy and climate targets.

On December 11, 2019, the European Commission presented the **European Green Deal**[3] – a roadmap for making the EU's economy sustainable by turning climate and environmental challenges into opportunities across all policy areas and making the transition just and inclusive for all. The European Green Deal covers all sectors of the economy, notably transport, energy, agriculture, buildings, and industries, such as steel, cement, ICT, textiles and chemicals.

On January 14, 2020, the European Commission presented the European Green Deal's Investment Plan - the **Sustainable Europe Investment Plan**- that will mobilise public investment and help to unlock private funds through EU financial instruments, notably InvestEU, which would lead to at least €1 trillion of investments.

While all Member States, regions and sectors will need to contribute to the transition, the scale of the challenge is not the same for everyone. Some regions will be particularly affected and will undergo a profound economic and social transformation. The **Just Transition Mechanism** is designed to provide tailored financial and practical support to generate the necessary investments and help affected workers in those areas.

On March 4, 2020, the European Commission proposed a **European Climate Law**[4] to ensure a climate neutral European Union by 2050. EU Institutions and Member States are collectively bound to take the necessary measures at EU and national level to meet the

[1] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2015:80:FIN
[2] https://ec.europa.eu/energy/topics/energy-strategy/energy-union/fifth-report-state-energy-union_en
[3] https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1588580774040&uri=CELEX:52019DC0640
[4] https://ec.europa.eu/clima/policies/eu-climate-action/law_en

target. The Climate Law includes measures to keep track of progress and adjust EU actions accordingly, based on existing systems such as the governance process for Member States' National Energy and Climate Plans, regular reports by the European Environment Agency, and the latest scientific evidence on climate change and its impacts. Progress will be reviewed every five years, in line with the global stocktake exercise under the Paris Agreement.

On July 8, 2020, the EU adopted strategies for energy system integration[5] and hydrogen[6], aiming to become climate-neutral by 2050. The plans aim to transform Europe's energy system, which accounts for 75% of the EU's greenhouse gas emissions, paving the way towards a more efficient and interconnected energy sector, driven by the twin goals of a cleaner planet and a stronger economy. (1) According to the European Commission, the two strategies present a new clean energy investment agenda, in line with the post-Covid-19 Recovery and Resilience Fund (RRF) and the European Green Deal[7]. According to EU officials, the planned investments have the potential to stimulate the economic recovery from the coronavirus crisis. In their view, they create European jobs and boost the bloc's leadership and competitiveness in strategic industries, which are crucial to Europe's resilience.

EU Executive Vice-President for the Green Deal, Frans Timmermans, said if Europe wants to become the first climate neutral continent by 2050, it needs to switch its energy systems from fossil fuels to clean. He said the strategies adopted on July 8 will bolster the European Green Deal and the green recovery, and put the EU firmly on the path of decarbonising its economy by 2050. "The new hydrogen economy can be a growth engine to help overcome the economic damage caused by COVID-19. In developing and deploying a clean hydrogen value chain, Europe will become a global frontrunner and retain its leadership in clean tech," Timmermans said.

At the same time, EU Energy Commissioner Kadri Simson noted that with 75% of the EU's greenhouse gas emissions coming from energy, the EU needs a paradigm shift to reach the stated 2030 and 2050 targets. "The EU's energy system has to become better integrated, more flexible and able to accommodate the cleanest and most cost-effective solutions. Hydrogen will play a key role in this, as falling renewable energy prices and continuous innovation make it a viable solution for a climate-neutral economy," Simson said.

The EU Strategy for Energy System Integration will provide the framework for the green energy transition, the European Commission said, adding that the current model where energy consumption in transport, industry, gas and buildings is happening in 'silos' – each with separate value chains, rules, infrastructure, planning and operations – cannot deliver climate neutrality by 2050 in a cost-efficient way; the changing costs of innovative solutions have to be integrated in the way we operate our energy system. New links between sectors must be created and technological progress exploited.

In EC's view, energy system integration means that the system is planned and operated as a whole, linking different energy carriers, infrastructures, and consumption sectors, and so by becoming connected and flexible, the system can be characterized as more efficient and can reduce costs for society. "For example, this means a system where the electricity that fuels Europe's cars could come from the solar panels on our roofs, while our buildings are kept warm with heat from a nearby factory, and the factory is fuelled by clean hydrogen produced from off-shore wind energy," they note. Hence, the EC's Energy System Integration strategy sets out 38 actions to link different energy carriers, infrastructures and sectors and exploit technological progress, while its Hydrogen Strategy will support the decarbonisation of industry, transport and other sectors across Europe, through investments, regulation,

[6] https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf
[6] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
[7] https://eurlex.europa.eu/legal-content/EN/TXT/?qid=1576150542719&uri=COM%3A2019%3A640%3AFIN

market creation, and research and innovation. (2) According to the European Commission, this gradual transition will require a phased approach. From 2020 to 2024, the EU will support the installation of at least 6 GW of renewable hydrogen electrolysers in the EU, and the production of up to 1 million tonnes of renewable hydrogen. From 2025 to 2030, hydrogen needs to become an intrinsic part of our integrated energy system, with at least 40 GW of renewable hydrogen electrolysers and the production of up to 10 million tonnes of renewable hydrogen in the EU. From 2030 to 2050, renewable hydrogen technologies should reach maturity and be deployed at large scale across all hard-to-decarbonise sectors, the Commission said.

EU Internal Market Commissioner Thierry Breton said the European Clean Hydrogen Alliance also launched on July 8, 2020, will channel investments into hydrogen production. "It will develop a pipeline of concrete projects to support the decarbonisation efforts of European energy intensive industries such as steel and chemicals. The Alliance is strategically important for our Green Deal ambitions and the resilience of our industry," Breton said.

WindEurope hailed on July 8 the EU's decision to promote direct electrification across the whole economy and the use of renewable hydrogen in hard-to-abate sectors. "It's good these new EU Strategies recognise the primary role of direct electrification," WindEurope CEO Giles Dickson said. "Electrifying heating, transport and industry directly via renewables is the cheapest and most efficient way to decarbonise energy. Renewables are well over a third of Europe's electricity and rising. We now have to get renewable electricity into heating, transport and industry," he added.

Other important EU energy and climate policies include the **Renovation Wave Strategy**[8], presented on October 14, 2020, in order to improve the energy performance of buildings. The European Commission aims to at least double renovation rates in the next ten years and make sure they lead to higher energy and resource efficiency. This will enhance quality of life, reduce Europe's greenhouse gas emissions, foster digitalisation and improve the reuse and recycling of materials. By 2030, 35 million buildings could be renovated and up to 160,000 additional green jobs created in the construction sector, based on EC estimates.In addition, the European Commission presented on November 19, 2020 the **EU Strategy on Offshore Renewable Energy**[9]. The Strategy proposes to increase Europe's offshore wind capacity from its current level of 12 GW to at least 60 GW by 2030 and to 300 GW by 2050. The Commission aims to complement this with 40 GW of ocean energy and other emerging technologies such as floating wind and solar by 2050.

On February 24, 2021, the European Commission adopted a new **EU Strategy on Adaptation to Climate Change**[10], setting out the pathway to prepare for the unavoidable impacts of climate change. Building on the 2013 Climate Change Adaptation Strategy, the aim of the new proposals is to shift the focus from understanding the problem to developing solutions, and to move from planning to implementation.

On July 14, 2021, the European Commission presented the much awaited **"Fit for 55"** legislative package. The "55" refers to the 55% net emissions reduction target by 2030 relative to 1990 levels, which EU leaders signed off on in 2020, superseding a previous goal of a 40% reduction. The aim of the "Fit for 55" package is to update the EU's 2030 climate and energy laws to reflect this higher target. On June 24, 2021, the European Parliament voted in favor of an agreement with the EU Council on the bloc's revamped greenhouse gas emissions reduction targets for 2030 and 2050. The vote made the EU's 2030 and 2050 climate targets legally binding and cleared the way for the European Commission's package of legislative proposals on climate and energy on July 14,

8 https://ec.europa.eu/energy/sites/ener/files/eu_renovation_wave_strategy.pdf
9 https://ec.europa.eu/commission/presscorner/detail/en/ip_20_2096
10 https://ec.europa.eu/clima/sites/clima/files/adaptation/what/docs/eu_strategy_2021.pdf

2020, which aimed to deliver on the overarching target. The vote means the Parliament has given its final rubber stamp on a provisional deal it reached with the EU Council April 21, 2021.

The "Fit for 55" package consists of a set of inter-connected proposals, which all drive towards the same goal of ensuring a fair, competitive and green transition by 2030 and beyond. Where possible, existing legislation is made more ambitious and where needed new proposals are put on the table. Overall, the package strengthens eight existing pieces of legislation and presents five new initiatives, across a range of policy areas and economic sectors: climate, energy and fuels, transport, buildings, land use and forestry. The legislative proposals are backed by impact assessment analysis, which takes into account the interconnection of the overall package. The analysis shows that an over-reliance on strengthened regulatory policies would lead to unnecessarily high economic burdens, while carbon pricing alone would not overcome persistent market failures and non-market barriers. The chosen policy mix is therefore a careful balance between pricing, targets, standards and support measures[11].

Table 3.1 **The Selected Policy Mix of the "Fit for 55" Package**

Pricing	Targets	Rules
•Stronger Emissions Trading System including in aviation •Extending Emissions Trading to maritime, road transport, and buildings •Updated Energy taxation Directive •New Carbon Border Adjustment Mechanism	•Updated Effort Sharing Regulation •Updated Land Use Land Use Change and Forestry Regulation •Updated Renewable Energy Directive •Updated Energy Efficiency Directive	•Stricter CO_2 performance for cars & vans •New infrastructure for alternative fuels •ReFuelEU: More sustainable aviation fuels •FuelEU: Cleaner maritime fuels
Support measures		
• Using revenues and regulations to promote innovation, build solidarity and mitigate impacts for the vulnerable, notably through the new **Social Climate Fund and enhanced Modernisation and Innovation Funds.**		

Source: European Commission

This Chapter also includes two special European energy policies that need to be further highlighted, as they are expected to play a vital role towards carbon neutrality by 2050: (a) EU Energy Taxonomy, including decarbonization issues in SE Europe and (b) the EU's Recovery and Resilience Facility.

3.1 2030 EU Climate and Energy Targets

For reference purposes, the current key EU Climate and Energy targets for 2030 are summarized as follows (3):

- At least 40% cuts in GHG emissions (from 1990 levels)
- At least 32% share of renewable energy
- At least 32.5% improvement in energy efficiency

Figure 3. 1 **Current 2020 and 2030 EU Agreed Climate and Energy Targets**

	GREENHOUSE GAS EMISSIONS	RENEWABLE ENERGY	ENERGY EFFICIENCY	INTER-CONNECTION	CLIMATE IN EU-FUNDED PROGRAMMES	CO2 FROM:
2020	-20%	20%	20%	10%	2014-2020 20%	
2030	≤ -40%	≤ 32%	≤ 32.5%	15%	2021-2027 25%	CARS -37.5% Vans -31% Lorries -30%

Source: European Commission

Achieving a 55% GHG emissions reduction by 2030 requires an increased share of renewable energy in the range of 38% to 40% of gross final consumption, according to Commission President Ursula von der Leyen in her first State of the European Union speech (4).

The power sector will continue to move away from fossil fuels, which would generate less than 20% of the EU's electricity by 2030, while renewables would supply around two-thirds of the EU's electricity. The Commission's Impact Assessment indicates that final and primary energy consumption would further fall by 2030, while achieving savings of 36%-37% on energy efficiency. In heating and cooling, renewables could achieve around 40% penetration in 2030, mainly through switching fuels towards renewable heating solutions of which heat pumps are the fastest growing application area. Buildings will become more energy efficient and rely less on fossil fuels for heating and cooling.

[11] https://ec.europa.eu/info/sites/default/files/chapeau_communication.pdf

As a result, by 2030, emissions from buildings would decrease by around 60% compared to 2015, the European Commission notes.

In the transport sector, as calculated in the Renewable Energy Directive, renewables could reach around 24% through further development and deployment of electric vehicles, advanced biofuels and other renewable and low carbon fuels. Revised CO_2 emission standards for cars and vans will ensure enough clean cars are available on the market. Supporting this transition will require a corresponding roll-out of recharging and refuelling infrastructure by 2030. As part of the Green Deal, the European Commission wants to place 1 million new charging points across the EU. Initially, the 2030 target for greenhouse gas (GHG) emissions reduction, compared to 1990 levels, in the EU was 40%.
On September 17, 2020, the European Commission proposed to raise that to 55%, but the EU Parliament on October 6 upped the ante, voting to raise the bloc's climate target to 60%, putting capitals under pressure.

Some Member States argued that the European Commission's proposal to increase the 2030 target from 40% to at least 55% does not adequately reflect their different starting points. Moreover, they consider that the proposal does not provide sufficient burden-sharing mechanisms based on the compensation for Member States with coal-dependent economies.

The vote in the European Parliament in favour of increasing the target to 60% challenged Member States with high GHG emissions and lower GDP per capita. These Member States were concerned that the burden of the transition cost will not be evenly distributed across the European Union, which might reinforce or even create new inequalities within the EU. The European Commission, Member States and European Parliament finally reached agreement on April 21, 2021 to raise the emissions reduction target to 55% relative to 1990 levels. But getting there wasn't easy.

3.2 Opposition from EU Member States

On October 23, 2020, EU environment ministers struck a deal to make the bloc's 2050 net-zero emissions target legally binding, but left a decision on a 2030 emissions-cutting target for leaders to discuss in December. None of the 27 member countries rejected the bill, although Bulgaria abstained. (5) Earlier, the European Commission said that the bloc needs a cut of at least 55% by 2030, against 1990 levels, in order to achieve the goal of net zero emissions by 2050, which all 27 countries, bar coal-dependent Poland, had committed to. The leaders did not endorse a specific 2030 target on October 15, but agreed to "return to the issue" in December, with the aim of finalising the goal by year-end. (6)

The EU takes decisions by unanimity. Once countries agree a common position on the 2030 target, they must strike a deal with the European Parliament, which proposed a 60% emissions cut. Leaders agreed to postpone the deal until countries have more information on the national impact of the target. That placated Poland, which said it could not back a new climate goal without this analysis.

Accordingly, the Council of EU leaders invited the Commission "to conduct in-depth consultations with member states to assess the specific situations and to provide more information about the impact at member states' level", a joint statement said. (7)

It also confirmed the 2030 emissions-cutting target would be met "collectively" at EU level. This could help convince the Czech Republic, which recently said it could support an EU-wide 55% emissions cut by 2030, but that it could not achieve that goal itself at a national level. Roughly half of the EU's 27 members - including Germany, France, Spain, Latvia and Denmark - said they supported the "at least 55%" goal. Needless to point out that the target would usher in sweeping changes to EU policies, including tighter car emissions standards and higher carbon costs for industry and airlines.

[12] https://www.ecologic.eu/sites/default/files/publication/2020/eu2030-ia-analysis_final.pdf

Increasing the European Union's 2030 emissions reduction target from 40% to at least 55% would require the bloc to almost entirely phase out coal by that date, according to a new report from the consultancy Climact and think tank Ecologic[12]. The analysis of the European Commission's impact assessment, accompanying its proposal to increase the target last September, found that coal could only represent around 2% of the EU's energy mix under any scenario meeting the target, down from the current 15%. (8)

This would mean many EU countries would have to dramatically adjust their coal phase-out plans. For instance, Germany has a plan in place which would see coal phased out by 2038 at the latest. Poland, which is heavily reliant on coal and has set a phase-out date for 2049, may have a difficult time meeting such a target - or at least have difficulty getting it accepted politically. Together, Poland and Germany account for half of the EU's coal emissions. Most EU countries have set coal phase-out plans that would end its use before 2030. Romania, Bulgaria, Czech Republic, Slovenia and Croatia have not set any specific coal phase-out date yet. Instead they are openly making noises insisting that a compensation arrangement is agreed beforehand, prior to committing to any coal phase-out plan.

At the same time, the Commission does not agree that meeting the 55% target would require a near-complete phase-out from coal. According to its impact assessment, coal would only have to be reduced by 70% by 2030 compared to 2015. Oil and gas, on the other hand, would have to be reduced by 30% and 25% respectively. Conservatives in the European Parliament's EPP group, a pan-European political family that includes Germany's Angela Merkel and Commission President Ursula von der Leyen as members, are concerned that the 55% target is already too ambitious. Climate campaigners, on the other hand, say 55% will not be enough to meet the emissions reduction trajectory required to meet the EU's commitments under the Paris Agreement. They say a 65% target would be needed. "It is important in these times to submit proposals that are in line with what scientists said it is necessary", argues Imke Lübbeke from the campaign group WWF. (9)

As if a coal phase-out was not enough, the EC's latest thinking and indirect actions (i.e. EIB, EU Taxonomy) suggest that next in line would be a complete gas phase out (see "Policy Inconsistencies Concerning Gas Use in SE Europe" in Special Focus 1: EU Energy Taxonomy). That would clearly undermine efforts by SEE countries, which will be trying to decarbonize by first transitioning to gas.

3.3 The Case of SE Europe

The current energy issues of the SE European countries, including EU and Energy Community member states, concern primarily the further use of indigenous resources, both conventional and renewable, which inevitably give rise to different approaches at local level, often leading to conflicting policy views.

One major issue is the sustained development of coal and lignite resources, which are abundant in Greece, Bulgaria, Kosovo, Serbia, Bosnia and Herzegovina and Turkey. Solid fuel use in the power generation sector in these countries is responsible for many thousands of jobs, and forms the basis of an extensive industrial base. Yet, there is a disturbing lack of well thought-out regional policies in SE Europe in such areas as Carbon Capture and Storage (CCS) and Carbon Capture, Utilization and Storage (CCUS) that could see the prolongation in the life of local coal and lignite industries and the smooth transition to decarbonized power generation.

Today, regional energy policies, as defined in the context of the Energy Union, do not leave much room for developing regionally advantageous policies, including coal use through CCS. The phasing out of all CO_2 generating plants by 2030 at the latest, is a clear target pursued by the EU.

[12] https://www.ecologic.eu/sites/default/files/publication/2020/eu2030-ia-analysis_final.pdf

Therefore, we have a potentially explosive situation with wide ranging social implications if lignite- and coal-fired power plants start closing down en masse, sending thousands of people to early retirement or unemployment.

Politics the EU and SE Europe have become polarised over past decade by inequality and immigration. The forced closure of coal- and lignite-fired power plants and mines in many countries will help to undermine economic development and will most likely give rise to widespread social unrest, creating a new source of unhappiness for populist parties to exploit. A similar but less disturbing situation could arise with oil and gas exploration and production activities. Several countries in the SE European region are actively seeking to explore oil and gas deposits, despite the ongoing COVID-19 pandemic and the huge impact on oil demand and prices, since this region as a whole is a net hydrocarbon importer (see Chapter 9). Almost all countries in the region are reporting promising hydrocarbon deposits, with some of them, notably Albania, Croatia, Serbia and Romania, having developed extensive production facilities and with Greece, Montenegro, Bulgaria, Cyprus and recently Turkey[13] having announced ambitious plans for oil and gas production and exports.

A potentially conflicted situation could even arise in the benign field of renewables (RES) as many countries in SE Europe have abundant solar, wind, geothermal, biomass and hydro potential (see Table 3.2), which they will seek to develop further to the fullest possible extent. With SE Europe as a whole possessing a huge excess capacity of RES, its rapid exploitation in the near future may lead to countries seeking ways to export competitively priced RES-generated electricity to central and northern Europe.

Even if we were to overcome the present lack of appropriate transmission infrastructure, at some point potential RES electricity sellers could be forced to offer prohibitively low tariffs. Alternatively, electricity market operators could decline Mediterranean electricity inputs as has already happened in the case of the ill-fated Helios project (10).

Table 3. 2 **Technical Potential for Utility-scale Solar PV, Wind and Hydropower in the Electricity Sector in SE Europe (TJ)**

	Utility-scale solar PV	Onshore wind	Hydropower
Albania	13 342	49 154	56 059
Bosnia and Herzegovina	14 886	94 810	88 193
Bulgaria	36 468	190 264	48 071
Croatia	15 682	104 951	30 600
Kosovo*	3 006	13 860	4 853
Montenegro	3 874	23 332	18 079
North Macedonia	8 014	27 558	14 421
Republic of Moldova	21 758	180 450	12 099
Romania	92 902	554 522	136 800
Serbia	33 509	188 590	64 800
Slovenia	1 613	8 266	58 539
SEE	245 052	1 436 156	532 515

TJ = Terajoule

Source: IRENA [14]

As analysed in IENE's "SE Europe Energy Outlook 2016-2017" study (11) and still valid today, the energy policies of most countries in the SE European region seem to amount to the following set of priorities:

1. Further large-scale development of coal and lignite resources without any CCS/CCUS provisions and plans, followed by gas use
2. Promotion of oil and gas exploration activities onshore and offshore aiming towards maximizing production in the mid- and long-term
3. Developing further renewables in all application areas – solar, wind, biomass, hydro and geothermal – but without necessarily adhering to the specific ceiling targets set by the EU
4. Promoting energy efficiency, focusing primarily on the building sector
5. Developing interconnectivity of electricity and gas systems
6. Diversifying energy supply routes and supplies

[13] Bektas, C. (2020), "Turkey discovers 320bcm of natural gas reserves in Black Sea", https://www.icis.com/explore/resources/news/2020/08/21/10543949/turkey-discovers-320bcm-of-natural-gas-reserves-in-black-sea

[14] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Dec/IRENA_Market_Analysis_SEE_2019.pdf

7. Reducing CO_2 levels by implementing new, low carbon technologies, and higher penetration of cleaner fuels in the energy and electricity mix

If countries in the region could agree to reverse their current coal-centred power generation priorities, we may start to see the region's natural advantages in clean energy coming to the fore. For example, the West Balkans have attractive assets for supporting Europe's energy transition: (a) large opencast coal mines with excellent grid infrastructure that can be used for industrial solar, wind, geothermal and biomass activities, (b) low labour costs, (c) engineering skills and (d) geographic proximity to advanced industrial economies with rising energy demand. With the right incentives, these assets could attract investments in the new wave of low-carbon industries and further contribute to the European industrial transition. The EU could extend several international co-operation initiatives to include the Western Balkans in the European Green Deal. Among them are the Energy Community, the European Network of Transmission System Operators for Electricity, the Regional Cooperation Centre, Central and South Eastern Europe Energy Connectivity, the Berlin Process, and others. Each of these brings value and tools for achieving the required energy transformation, and for guiding the SEE region towards hosting modern low-carbon, high added-value industries.

International financial institutions, such as the EIB, the EBRD and the World Bank could play key role in this energy transformation of SE Europe. Most of these organisations follow strong climate-aligned policies. (Recently, the EIB branded itself the "European climate bank", pulled out of investment in fossil fuel projects and announced that it "will align all financing activities with the goals of the Paris Agreement from the end of 2020"). (12)

If the EU really wants to maximise the impact of the European Green Deal and make it economically more attractive to all governments, it should incorporate the Western Balkans and ensure that the countries there are part of the negotiation process. In this way, the EU will not only guide the region towards the 2030 and 2050 targets. It would also be able to extract the maximum value the Western Balkans could offer. This will make the European Green Deal an all-encompassing one, based on a clear mutual interest in which the Balkans will not fall into the usual role of a receiver of policy and a reluctant follower of regulations, but will instead be an active contributor.

To achieve this, the West Balkans countries themselves should consider teaming up as an inter-governmental negotiating bloc. They could then assemble an international technical assistance team that would help negotiators evaluate the clean economy assets of the region and identify the most economically beneficial paths towards rapid greenhouse gas reduction.

Discussion

The COVID-19 crisis, the EU energy system integration process and hydrogen strategies, accelerated by the Recovery and Resilience Fund and the European Green Deal, are creating huge opportunities for increasing RES penetration in the SE European energy and electricity mix. The green stimulus packages could accelerate the switch to renewable energy in SE Europe, attracting numerous investments and creating new jobs, while new green technologies, such as green hydrogen, could be very important complements to renewable-based electricity.

To ensure sustained RES investment, it is essential to create an enabling environment by introducing appropriate and dedicated policies. The region has indeed proved that it can attract investment when supporting policies and measures are in place. These measures should go beyond mere direct RES support and include, in addition, system regulation and integration with the everyday life of energy consumers. The transformation of the existing polluting SEE energy system into a sustainable one should be based on localised policies and differentiated energy sources of higher energy efficiency, with a view towards tapping hydrogen generation. Energy cooperation between the various countries in the region is of paramount importance in order to introduce lasting changes aiming towards sustainability. Hydrogen produced from renewables could play a decisive role in achieving such sustainability and should be examined in great detail for each different country of the region.

However, energy sector regulations in the region have historically favoured and subsidised fossil fuels. Reversing such long-held attitudes and creating a favourable regulatory and licensing framework for RES would require drastic reforms. Some are already underway (e.g. see Greece's aggressive decarbonization programme). International agreements, such as the Energy Community Treaty, the EU Renewable Energy Directives and the Paris Agreement, have provided some stimulus. The combination of high RES potential, falling renewable energy costs and new policies and regulations in the energy sector make SE Europe ideal for large-scale RES deployment. However, sound policies rooted in the recognition of the socio-economic impact of the energy sector and making allowance for proper financial co-operation are needed to fully achieve the energy transition in the region.

IRENA (13) estimates that shifting the regional energy system to RES would increase the economy of SE Europe by 2% per annum until 2040 and 1% from then on until 2050, compared to a business-as-usual (BAU) scenario, translating into a cumulative gain of more than $485 billion. The creation of new jobs in RES would also help tackle long-standing unemployment and brain drain issues. The inclusion of social benefits, such as improvements in health and air quality, ensures that potential gains further outweigh additional costs. According to certain scenarios, current commitments and policies at global level are expected to lead to a global temperature increase of 3°C-4°C by the end of the 21st century, a catastrophic scenario involving estimated losses for the EU alone of more than €175 billion every year by mid-century, based on the European Commission's estimates.

To keep the 1.5°C goal of the Paris Agreement within reach and prevent the more dangerous and radical climate change repercussions, the EC says that a substantially increased climate target of at least 65% emission cuts by 2030 should be adopted, which it considers the only target in line with the latest science available and the United Nations' equity principles. This is well beyond the "at least 55% target" of the European Commission. The European Parliament called for 60% emission cuts and Denmark, Finland and Sweden pledged their support for 60%-65% in the Council discussions. (14)

However, a recent joint CAN Europe and Ember study (15), which has analysed the National Energy and Climate Plans (NECPs) of seven EU Member States (Bulgaria, Croatia, the Czech Republic, Germany, Poland, Romania and Slovenia) in line to receive the lion's share of the Just Transition Fund, points out that these countries do not have any plans to phase-out coal in the next decade; though their NECPs show that a number of them is also planning an increased role for gas in their electricity transitions. Of the eleven countries expected to phase-out coal by 2030, the study indicates that only four (Greece, Hungary, Ireland and Italy) are planning a significant coal-to-gas transition.

According to latest euro thinking, the EU must achieve climate neutrality by 2050 in order to do its fair share under the Paris Agreement and to limit the global temperature increase to 1.5°C. This means that all Member States should phase out coal by 2030 and all fossil fuels by 2050 at the latest, according to the CAN Europe/Ember study. A close look at the NECPs shows that several Member States are not in line with the European 2050 climate neutrality objective or the proposed new high targets by 2030. To sum up, although the new 2030 EU Climate and Energy Targets sound really ambitious, the current status of most EU Member States indicates that a lot more work needs to be done. Hence, it is highly debateable whether these new sky high targets can actually be achieved under present policies.

References

(1) European Commission (2020), "Powering a climate-neutral economy: Commission sets out plans for the energy system of the future and clean hydrogen", Press Release, https://ec.europa.eu/commission/presscorner/detail/en/ip_20_1259

(2) Geropoulos, K. (2020), "EU outlines energy system, clean hydrogen plans for climate-neutrality by 2050", New Europe Online, https://www.neweurope.eu/article/eu-outlines-energy-system-clean-hydrogen-plans-for-climate-neutrality-by-2050/

(3) European Commission (2020a), "2030 climate & energy framework", https://ec.europa.eu/clima/policies/strategies/2030_en

(4) European Commission (2020b), "State of the Union: Questions & Answers on the 2030 Climate Target Plan", https://ec.europa.eu/commission/presscorner/detail/en/QANDA_20_1598

(5) Abnett, K. (2020), "EU environment ministers strike deal on climate law, leave out 2030 target", Reuters, https://www.reuters.com/article/us-climate-change-eu/eu-environment-ministers-strike-deal-on-climate-law-leave-out-2030-target-idUSKBN27811W

(6) Abnett, K. and Guarascio, F. (2020), "EU leaders aim for deal in December on climate change target", Reuters, https://www.reuters.com/article/us-eu-summit-climate/eu-leaders-aim-for-deal-in-december-on-climate-change-target-idUSKBN2701EN

(7) European Council (2020), "European Council conclusions on COVID-19 and climate change, 15 October 2020", https://www.consilium.europa.eu/en/press/press-releases/2020/10/16/european-council-conclusions-on-covid-19-and-climate-change-15-october-2020/

(8) Meessen, J. et al. (2020), "Analysing the Impact Assessment on Raising the EU 2030 Climate Target", A Joint Climact and Ecologic Institute Study, https://www.ecologic.eu/sites/files/publication/2020/eu2030-ia-analysis_final.pdf

(9) Keating, D. (2020), "EU's New 2030 Climate Target Could Mean Exit From Coal By 2030", Forbes, https://www.forbes.com/sites/davekeating/2020/10/05/eus-new-2030-climate-target-could-mean-exit-from-coal-by-2030/#aeaede051ac5

(10) IENE (2012), "Project Helios: Can Solar Energy be Exported?", An IENE Study (M11), https://www.iene.gr/articlefiles/the%20helios%20study%20iene%20ix%20cs%20final%20draft%2022%2002%202012%20new.pdf

(11) IENE (2017), "SE Europe Energy Outlook 2016-2017", http://www.iene.eu/SEEEO-2015-2016-Promotional%20Booklet-p2317.html

(12) European Investment Bank (2019), "EU Bank launches ambitious new climate strategy and Energy Lending Policy", Press Release, https://www.eib.org/en/press/all/2019-313-eu-bank-launches-ambitious-new-climate-strategy-and-energy-lending-policy

(13) RENA (2019), "Renewable Energy Market Analysis: Southeast Europe", https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Dec/IRENA_Market_Analysis_SEE_2019.pdf

(14) Szewczyk, W. et al. (2020), "Economic analysis of selected climate impacts", JRC Technical Report, https://publications.jrc.ec.europa.eu/repository/bitstream/JRC120452/pesetaiv_task_14_economic_analysis_final_report.pdf

(15) Gündüzyeli, E. et al. (2020), "Just Transition or Just Talk?", A Joint CAN Europe and Ember Study, http://www.caneurope.org/publications/reports-and-briefings/1988-just-transition-or-just-talk-2020

Special Focus 1: EU Energy Taxonomy

In order to meet the EU's climate and energy targets for 2030, in line with the European Green Deal, it is important to direct investments towards sustainable projects and activities. "The current COVID-19 pandemic has reinforced the need to redirect capital flows towards sustainable projects in order to make our economies, businesses and societies, in particular health systems, more resilient against climate and environmental shocks and risks with clear co-benefits for health", underlines the EC. (1)

To achieve this, a common language and a clear definition of what is "sustainable" is needed. This is why the EU's action plan on financing sustainable growth called for the creation of a common classification system for sustainable economic activities, otherwise known as "EU taxonomy".

What is the EU Taxonomy?

The EC believes that its taxonomy is an important tool to scale up sustainable investment and implement the European Green Deal. It is expected to create security for investors, prevent greenwashing[15], help companies plan their transition, mitigate market fragmentation and eventually help shift investments where they are most needed.

Taxonomy Regulation and Delegated Acts

The Taxonomy Regulation[16] was published in the Official Journal of the European Union on 22 June 2020 and entered into force on 12 July 2020. It establishes six environmental objectives:

1. Climate change mitigation
2. Climate change adaptation
3. The sustainable use and protection of water and marine resources
4. The transition to a circular economy
5. Pollution prevention and control
6. The protection and restoration of biodiversity and ecosystems

Different means can be required for an activity to make a substantial contribution to each objective. The Taxonomy Regulation tasks the Commission with establishing the actual list of environmentally sustainable activities by defining technical screening criteria for each environmental objective through delegated acts. Currently, there appear to be two energy subsectors - nuclear power and natural gas - whose status as environmentally sustainable forms of energy remain in doubt and hence their classification is at stake.

Assessment of Nuclear Energy

In 2020, the European Commission launched an in-depth investigation to assess whether to include nuclear energy in the EU taxonomy of environmentally sustainable activities. As the first step, the Joint Research Centre, the in-house science and knowledge service of the Commission, drafted a technical report on the "do no significant harm" aspects of nuclear energy. This publication is a Science for Policy report by the JRC, which aims to provide evidence-based scientific support to the European policymaking process.

It does not imply a policy position of the European Commission. The report will now be reviewed by two sets of experts, the Group of Experts on radiation protection and waste management under Article 31 of the Euratom Treaty, as well as the Scientific Committee on Health, Environmental and Emerging Risks on environmental impacts. Their reports are considered as vital as the JRC's report for the Commission's decision. According to a leaked document cited by Euractiv (2), experts tasked with assessing whether the European Union should label nuclear power as a green investment will say that the fuel qualifies as sustainable.

[15] Greenwashing is considered an unsubstantiated claim to deceive consumers into believing that a company's products are environmentally friendly.
[16] https://ec.europa.eu/info/law/sustainable-finance-taxonomy-regulation-eu-2020-852_en

EU countries are split concerning nuclear. A group of seven EU countries, including France, Hungary and Poland, urged the Commission to support nuclear power in policies and taxonomy. Other states, including Austria, and some environmental groups, oppose the fuel, pointing to its hazardous waste and the delays and spiralling costs of recent projects.

Assessment of Natural Gas

The European Union reportedly plans to label some gas-fired power plants as sustainable investments, after an initial proposal to deny them a green label provoked a backlash from a group of 10 EU member states.

The European Commission's new proposal, shared with EU countries on March 20, 2021, would class gas-fuelled plants that generate power plus heating or cooling as a green investment if strict conditions on emissions are met and the plants are operating by 2025. EU countries are split between those who say that such a decision would imply greenwashing, and those who see gas as crucial for them to abandon higher-polluting coal. (3)

It is an example of how mired taxonomy has become in disputes between EU countries over how to treat investments in natural gas, forcing the Commission to rewrite its original proposal dating to November 2020. Given the EU's negative assessment of natural gas thus far, and the EIB's binding decision to suspend funding to gas related projects from 1 January 2021, the questions surrounding the sustainability and viability of gas investments acquire new impetus.

Natural gas, a fossil fuel, produces roughly half the carbon dioxide emissions of coal when burned in a power plant. Countries including Poland, Germany and Greece plan to use gas to wean themselves off the more polluting fuel. However, gas is not emissions-free and leaks of potent planet-warming methane from gas infrastructure could cancel out the benefits of switching to gas from coal altogether.

However, from among current policy options, the switch from coal to gas for power generation offers the single most important and readily available way to halve power generation's emissions, and this constitutes a bold move towards GHG emission reduction. This is particularly important for SE Europe, where coal and lignite still have dominant role in power generation. Here, gas appears to be the only quick way to reduce substantially GHG emissions.

Strict Conditions

Under the draft plan, gas plants that generate power and also provide heating or cooling can be classed as a green investment if they replace a high-emitting fossil fuel-based facility and result in a cut in greenhouse gas emissions of at least 50% per kWh. The gas plant must be operating by 2025, have the potential to use low-carbon fuels in future (e.g. biomass, geothermal) and emit no more than 270 grams of CO_2 equivalent per kWh of energy.

For plants only producing power, or those that also provide heating or cooling but do not replace a more polluting plant, the Commission stuck to its plan to restrict the green label to plants with life-cycle emissions below 100g of CO_2 equivalent per kWh, according to the draft document. That means gas-fired power plants operating now would need to add technology to capture their emissions in order to qualify.

Critique on EU Taxonomy

In June 2020, following protracted negotiations, the European Parliament adopted at second reading the compromise regulation for the establishment of an EU framework (the so-called 'taxonomy') to facilitate sustainable investment. Years of intensive work and engagement with strategic stakeholders, since the publication of the Action Plan on Financing for Sustainable Growth in March 2018, led to an "ambitious" sustainable finance strategy with one key priority in line with EU solidarity: to leave no industry nor Member State behind.

The next step is the development of delegated acts establishing realistic and fair technical screening criteria and thresholds for sustainable economic activities eligible for financial support. The Commission's proposed delegated act for the EU Taxonomy for Sustainable Finance, released in December 2020, failed to deliver the promised solidarity priority.

Despite official public consultations carried out by the European Commission, the delegated act ignored the priorities of numerous stakeholders, from the aluminium and raw materials industries to the refining and energy sectors. It also left some member states frustrated by the Commission's disregard for their right to decide on their energy mix and appropriate technologies to achieve the 2030 climate target.

A leaked revised proposal, available since the second half of March 2021, still fails to meet the industry's needs – although a number of activities is now fully taxonomy-eligible. Nevertheless, the Commission's revised draft delegated act is, as it stands, "an ineffective plan for supporting businesses and member states across the Union in their attempt to transition towards sustainability", note Members of the European Parliament. (4)

A main criticism leveled against the Commission is that the set benchmarks narrow down the basket of technological climate solutions rather than broadening it. The revised delegated act still does not explicitly include liquid and gaseous transport fuels of non-biological origin and Recycled Carbon Fuels – even though these play a critical role in meeting climate goals. This clearly limits the solutions available to reduce CO_2 emissions in, for instance, the transport sector where electrification is not always technically possible. In practice, this means that we are jeopardising the sector's ability to remain competitive by limiting its access to diversified, affordable and sustainable energy. All low carbon liquid fuels (LCLF), alongside electrification and hydrogen technologies, are crucial in achieving carbon neutrality for all transport modes.

The European Commission should look to facilitate, rather than hinder, investments for the decarbonisation of European industry, note industry experts. By leveraging the technological expertise of the EU refining industry, they say, we could step up the ongoing green transformation and foster investments in promising technologies, such as sustainable liquid biofuels and all hydrogen-derived synthetic fuels. Feedback from member states and stakeholders to the December draft taxonomy criteria and thresholds highlights these concerns, which go unaddressed in the Commission's leaked revision.

Discussion

With the Commission's final taxonomy proposal still pending, the task at hand is to ensure that criteria and thresholds broaden the scope of technological climate solutions. The EU taxonomy has the potential to be a game-changer, but it must adopt a holistic approach, examining all possible solutions to meet climate objectives, moving beyond labels such as a "brown list" that appear to dictate what are "good" and "bad" technologies. "We need to ensure that there is a level playing field when comparing various technologies, especially low-carbon technologies for fuels, petrochemical feedstock, and other refinery products. Life-cycle analysis and impact assessments are promising methods to achieve fairness and accuracy, and they need to apply horizontally", note industry sources.

Launching a "Renewable and Low-Carbon Fuel Value Chain Alliance", mentioned by the Commission in its December 2020 Sustainable and Smart Mobility Strategy, would be a pragmatic starting point for a broad reflection on these issues with stakeholders involved in aviation, refining, marine, and road transport.
With the right mix of enabling sustainable finance conditions, the EU needs to send clear, long-term signals to guide businesses and investors towards sustainable growth. But for this to be efficient, the full engagement of all actors, from EU institutions and civil society to industry, is absolutely necessary.

Only then can a realistic and fair EU Taxonomy that drives the EU towards an affordable and pragmatic transition be achieved.

There is also a much broader critique at play. This has to do with EC's increasingly micromanagerial attitude and bureaucratic overreach. Leading economists argue that the EU's obsession with constantly expanding a list of prohibited climate-sensitive activities and precise guidance in core power generation is reminiscent of Soviet-era central planning.

Hence, the EC's argument that in order to achieve lower emissions and adopt clean technologies we need to strictly control the majority of economic activity reveals a departure from the liberal economy, which European leaders claim as a major EU achievement.

References

(1) *European Commission (2021), "EU taxonomy for sustainable activities", https://ec.europa.eu/info/business-economy-euro/banking-and-finance/sustainable-finance/eu-taxonomy-sustainable-activities_en#what*

(2) *Simon, F. (2021), "LEAK: EU experts to say nuclear power qualifies for green investment label", Euractiv, https://www.euractiv.com/section/energy-environment/news/leak-eu-experts-to-say-nuclear-power-qualifies-for-green-investment-label/*

(3) *Euractiv (2021), "EU to offer gas plants a green finance label, under certain conditions", https://www.euractiv.com/section/energy-environment/news/eu-to-offer-gas-plants-a-green-finance-label-under-certain-conditions/*

(4) *Asimakopoulou, A (2021), "Revising the EU taxonomy to fuel the journey towards industrial decarbonization", Euractiv, https://www.euractiv.com/section/energy-environment/opinion/revising-the-eu-taxonomy-to-fuel-the-journey-towards-industrial-decarbonization/*

Special Focus 2: EU's Recovery and Resilience Facility

According to the European Commission (1), the Recovery and Resilience Facility (RRF) will make €672.5 billion in loans and grants available to support reforms and investments undertaken by Member States. The aim is to mitigate the economic and social impact of the coronavirus pandemic and make European economies and societies more sustainable, resilient and better prepared for the challenges and opportunities of the green and digital transitions. The RRF entered into force on February 19, 2021.

Figure 3. 2 **EU's Recovery and Resilience Facility**

Source: European Commission

The Facility and NextGenerationEU

The Facility is the centerpiece of NextGenerationEU, billed as a temporary recovery instrument that allows the European Commission to raise funds to help member states repair the immediate damage of the coronavirus pandemic. The Facility is also closely aligned with the Commission's priorities ensuring in the long-term a sustainable and inclusive recovery that promotes the green and digital transitions.

National Recovery and Resilience Plans

Member States will prepare recovery and resilience plans that set out a coherent package of reforms and public investment projects. To benefit from the support of the Facility, these reforms and investments should be implemented by 2026.

The plans should effectively address challenges identified in the European Semester, particularly the country-specific recommendations adopted by the Council. The plans should also include measures to address the challenges and reap the benefits of the green and digital transitions. Each plan is expected to contribute to the four dimensions outlined in the 2021 Annual Sustainable Growth Strategy, which launched this year's European Semester cycle.

- Environmental sustainability
- Productivity
- Fairness
- Macroeconomic stability

The Facility is an opportunity to create European flagship areas for investments and reforms with tangible benefits for the economy and citizens across the EU. These should address issues that need significant investment to create jobs and growth, and which are needed for the green and digital transitions. The Commission strongly encourages Member States to put forward investment and reform plans in the areas shown in Figure 3.3.

Figure 3. 3 **Flagship Areas for Investments & Reforms**

Source: European Commission

For each of the flagships, there are EU-wide ambitions:

1. **Power up:** Support the building and sector integration of almost 40% of the 500 GW of renewable power generation needed by 2030, support the installment of 6 GW of electrolyser capacity and the production and transportation of 1 million tonnes of renewable hydrogen across the EU by 2025.
2. **Renovate:** By 2025, contribute to the doubling of the renovation rate and the fostering of deep renovation.
3. **Recharge and refuel:** By 2025, aim to build one out of the three million charging points needed in 2030 and half of the 1000 hydrogen stations needed.
4. **Connect:** Ensure that by 2025 there is the widest possible uninterrupted 5G coverage for all areas, including in rural and remote areas.
5. **Modernise:** By 2025, ensure the provision of a European digital identity (e-ID) and public administrations should be providing interoperable, personalised and user-friendly digital public services. In addition, public administrations should undertake reforms and investments to (re-)design processes, procedures and civil service according to best practices.
6. **Scale-up:** By 2025, double the production of semi-conductors in Europe, to produce 10 times more energy efficient processors and to double the share of EU companies using advanced cloud services and big data (from 16% today)
7. **Reskill and upskill:** By 2025, 50% of the adult population should participate in training each year. By 2025, the share of Europeans aged 16 to 74 with basic digital skills should increase to reach 70%. Education systems needs to be further adapted to the challenges of the 21st century. Member States should ensure that pupils' digital competence is significantly improved, in order to reduce the share of 13-14 year old students who underperform in computer and information literacy to under 15%. By 2025, at least four in five VET graduates should be employed and three in five should benefit from on-the job-training.

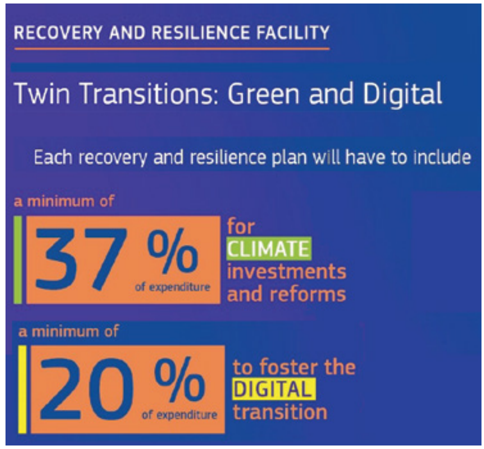
For each flagship to which a plan contributes, Member States are invited to provide an analysis of the existing national challenges (including the existence of market or systemic failures). In this regard, they are invited to describe their status quo (existing national strategies and targets) and how they can be further developed to meet the 2025 EU-wide ambitions of each flagship. Member States are invited to describe the relevant reforms and investments supported by the Facility.

This description may include the delivery models to implement the measures and the main actors involved. This includes how they would act as investments multipliers, contribute to employment creation and contribute towards creating beneficiaries who will co-finance projects and minimise competition distortions. Flagships can also be implemented through multi-country projects.

Green and Digital Priorities

The Recovery and Resilience Facility offers an unprecedented opportunity to speed up the recovery in Europe and reinforce the commitment to the twin transitions: green and digital. The Commission will assess the national plans against the targets shown in Figure 3.4.

Figure 3. 4 **Twin Transitions: Green and Digital**

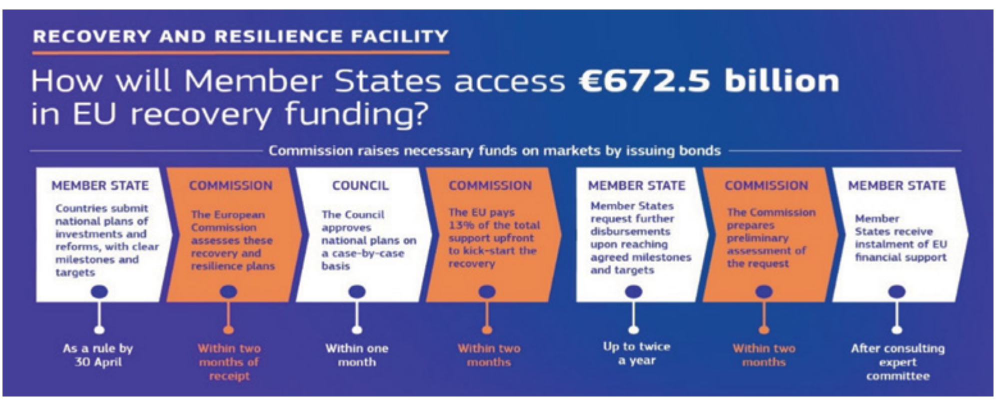


Source: European Commission

Timetable

The European Semester and the Recovery and Resilience Facility are intrinsically linked. The publication of the 2021 Annual Sustainable Growth Strategy launched this year's European Semester. It continues last year's growth strategy based on the European Green Deal and the concept of competitive sustainability.The Commission will assess recovery and resilience plans against the country-specific recommendations. As the European Semester and the Facility will overlap, it is necessary to temporarily adapt the European Semester. Member States are therefore encouraged to submit their national reform programmes and their recovery and resilience plans in a single integrated document, which will provide an overview of the reforms and investments that the Member States plan to undertake in the coming years, in line with the objectives of the Facility.

Figure 3. 5 **How Will Member States Access €672.5 billion in EU Recovery Funding?**



Source: European Commission

Reference

(1) *European Commission (2021), "Recovery and Resilience Facility", https://ec.europa.eu/info/business-economy-euro/recovery-coronavirus/recovery-and-resilience-facility_en*

Special Focus 3: Decarbonisation in SE Europe

Lately, decarbonisation as a concept and a coordinated set of actions has come to dominate Europe's current and long-term (i.e. 2030 and 2050) energy strategies. When considering SE European energy policy, decarbonisation will come to play an important role as it affects the whole spectrum of energy - from power generation to transport, building, industry, trade and services sectors. The ultimate objective is the reduction of Greenhouse Gas (GHG) emissions. The power sector is expected to play central role in the decarbonization process, as it is in a position to deliver fast and visible benefits, given the high volume of gases it produces.

Decarbonisation in the case of power generation means reduction of the sector's carbon intensity, which in turn means decline of the emissions per unit of electricity generated. Decarbonisation is of particular importance for coal-intensive regions, such as SE Europe, in order to transit into a "cleaner" energy mix. A gradual decarbonisation of the power sector can be achieved by increasing the share of low-carbon energy sources, like renewables and nuclear, as well as by capping GHG emissions from fossil fuel power stations through Carbon Capture and Storage (CCS) technology and Carbon Capture and Utilisation (CCU). A shift from "dirtier" fossil fuels, like coal (which emits on average 900g CO_2/kWh), to lower emissions fuels, like gas (which emits about 400g CO_2/kWh) and renewables, can also help to reduce power plant emissions. (1)

Reaching climate neutrality by 2050, as envisioned by the European Commission's strategic long-term vision, requires timely decarbonisation of the European energy sector, including a complete phase-out of coal (see Map 3.1). This will particularly affect regions which are dependent on the coal sector and other high-carbon industries, as they will have to follow a transition phase to low-carbon economies in the coming decades. This briefing offers a deep dive into the positioning of key stakeholders as well as opportunities and challenges for a transition away from coal in the coal-dependent SE European region.

Most governments in SE Europe, in contrast to the rest of Europe, remain committed to continuing coal use. Greece is until now the only country in SE Europe that is expected to shut down all its lignite-fired power plants by 2028[17], while North Macedonia's coal phase-out plan is still under discussion[18]. Based on IENE's estimates, the share of solid fuels for power generation is anticipated to hold its present position if not increase in several countries of the region (most notably in Serbia, Kosovo, Croatia, Bosnia and Herzegovina, Montenegro and Turkey[19]) over the next 10-15 years, as these countries will struggle to meet increasing energy demand. Hence, the road towards decarbonisation and the transition to a "greener" future in SE Europe, with higher use of natural gas and renewables (RES), appears difficult, if not uncertain, in comparison to the rest of Europe.

It seems that a far more realistic approach towards decarbonisation is required in the case of SE Europe. The necessity for such an approach is based on the fact that reforms are not easily being implemented, as there is a lack of social acceptance or of political will, or both.

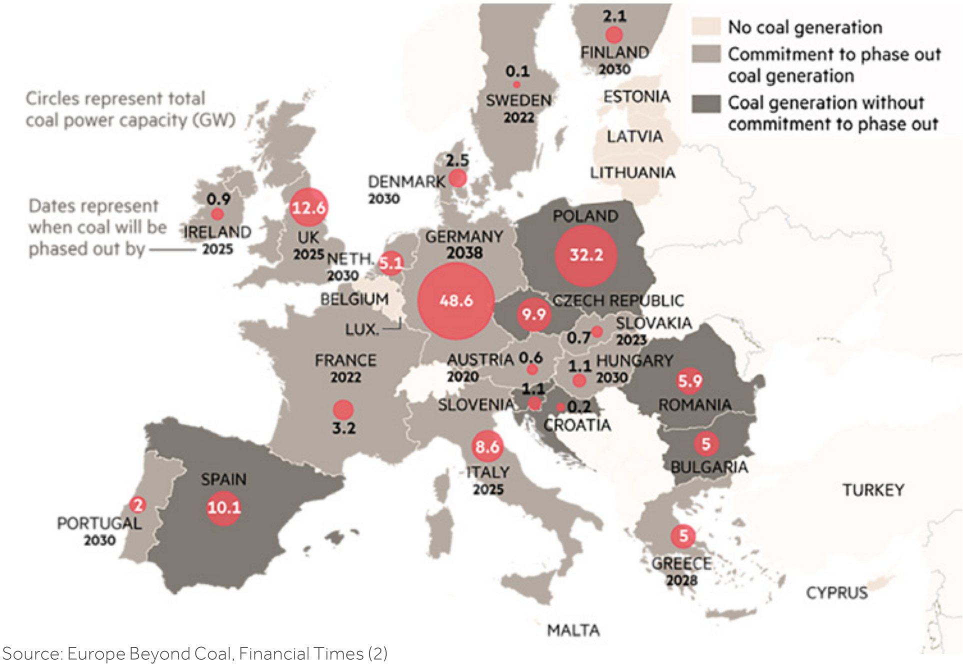
[17] In December 2019, Greece's Public Power Corporation (PPC) decided to cease operating all but one of its existing lignite-fired power plants by 2023. The only lignite-fired power plant remaining until 2028 is Ptolemaida V, which is currently under construction. PPC is now looking for a fuel conversion at the facility for lignite-free operation beyond 2028. Natural gas, biomass and waste-to-energy incineration, even a combination of all three generation methods, have been included as possible options in state-controlled PPC's new business plan.

[18] In February 2020, North Macedonia adopted a ground-breaking new energy strategy, making it the first country in the Western Balkans to name concrete date options for a coal phase-out. Two of the strategy's scenarios entail a coal exit by 2025, with the third delaying closure of the Bitola lignite-fired power plant until 2040. A final decision on which pathway to take will be made in 2021.

[19] Currently, all these SEE countries do not have any coal phase-out plan.

The Paris agreement (2015) marks the latest step in the evolution of the UN climate change regime, which originated in 1992 with the adoption of the United Nations Framework Convention on Climate Change (UNFCCC). The UNFCCC established a long-term objective, general principles, common and differentiated commitments, and a basic governance structure, including an annual Conference of the Parties (COP). The Paris agreement (COP21) is proving to be an important reference point and an accelerator for global energy transformation.

Map 3. 1 **Commitments of European Countries to Phase Out Coal**



Source: Europe Beyond Coal, Financial Times (2)

The main question arising for the countries in SE Europe, including the Western Balkan ones, is whether they are willing to substitute coal with other energy sources. SE Europe as a whole is a carbon-intensive region, with the exception of Albania whose energy sector is remarkably low-carbon, as its system relies almost fully on hydropower for electricity generation. Albania's goal will be to diversify its hydropower-dependent energy mix without increasing CO_2 emissions, while preserving biodiversity. For the rest of the countries in SE Europe, rich in solid fuels, the challenge will be how to diversify their energy mix progressively by minimizing coal use.

An appropriate energy mix appears to be the best vehicle towards achieving decarbonisation. Only through a combination of low-carbon energy sources (i.e. renewables and nuclear), as well as CCS/CCU technology, can this be achieved. However, in a carbon-intensive region such as SE Europe, detailed studies (currently lacking) must be conducted in order to identify the optimum energy mix, taking into consideration the persistent use of coal in the years ahead under a business-as-usual scenario. In order to achieve an optimum energy mix, a detailed strategy for the entire SEE region needs to be worked out, with short-, medium- and long-term targets.

It is only by following such studies that a clear roadmap for SE Europe's transition to a decarbonized state can be established.

Although CCS applications in SE Europe have made little progress, a comprehensive overview of currently available techniques and technologies is needed in order to be able to assess the availability and applicability of the CCS option in the region.

In almost all the SEE countries, local actors are driving the transition while national governments remain committed to coal as a basic energy source and maintain close ties to the coal industry. In Greece, local mayors are looking for alternative ways for the coal-rich region of Western Macedonia to develop, while in Kosovo, protests have taken place in villages affected by the expansion of mining activities. While transition strategies benefit from being driven by local stakeholders, guidance and policy frameworks from the national level are key as they provide stability and enable long-term planning. Among civil society voices, labour unions tend to be vocal opponents of measures that could impact on the coal sector.

The EU has a central role in supporting transition processes. Kosovo, North Macedonia and other countries in the Western Balkans share the aspiration of joining the EU and as part of the Energy Community they are already influenced by the Union's climate and energy policy. The EU sets targets for national climate and energy policies and through its budget has a powerful tool to support the transition away from coal.

Large amounts of indigenous coal and lignite deposits, which provide relatively cheap and easily accessible energy for most countries in the region, are preventing a determined move towards decarbonisation. As shown in the following Table, most countries in SE Europe have well-defined plans and ongoing projects for new coal/lignite-fired power plants. Over the next 8-10 years these plants will add some 10GW of new electricity capacity. Hence, the region's dependence on solid fuels is likely to increase, notwithstanding commitments for increased RES use.

Table 3. 3 **Under Construction and Planned Coal Plants in SEE Countries (MW)*, as of July 2020**

Country	Announced New Plants	Pre-permit	Permitted	Announced + Pre-permit + Permitted	Under Construction	Shelved	Operating	Cancelled (2010-2020)
Turkey	13,460	12,925	5,680	32,065	1,610	5,670	17,717	65,867
Bosnia & Herzegovina	1,830	600	1,100	3,530	0	550	2,073	1,020
Serbia	1,000	350	0	1,350	350	375	4,405	1,070
Romania	0	600	0	600	0	0	4,675	5,105
Kosovo	0	0	0	0	0	0	1,290	830
Hungary	0	0	0	0	0	0	944	3,520
Israel	0	0	0	0	0	0	4,900	1,260
Bulgaria	0	0	0	0	0	0	4,829	2,660
Greece	0	0	0	0	660	0	3,175	1,250
Slovenia	0	0	0	0	0	0	1,069	0
North Macedonia	0	0	0	0	0	0	800	730
Montenegro	0	0	0	0	0	0	225	1,664
Croatia	0	0	0	0	0	0	210	1,300
Albania	0	0	0	0	0	0	0	800

*Note: Includes units 30 MW and larger
Source: EndCoal (3), IENE

In Europe, there are initiatives towards a "greener" energy future such as the EU "Coal Regions in Transition Platform", launched in 2017 and included as a non-legislative element of the "Clean energy for all Europeans' package". The platform works as an open forum, gathering all relevant parties, local, regional and national governments, businesses and trade unions, NGOs and academia. It promotes knowledge-sharing and exchanges of experiences between EU coal regions, and represents a unique bottom-up approach to a just transition, enabling regions to identify and respond to their particular contexts and opportunities.

Since 2019, a secretariat has been set up to manage platform activities, covering events, provision of support materials and technical assistance to coal regions, including the Czech Republic, Germany, Poland, Slovakia, Spain and the SE European countries of Greece, Romania and Slovenia. In October 2019, a group of 41 mayors from 10 coal regions in 9 European countries launched a statement supporting a just transition to the post-coal era. (4)

Map 3. 2 **Signatories Declaration of Majors on Just Transition**

Source: WWF

On March 4, 2020, the European Commission adopted the European Climate Law proposal[20], which will enshrine in EU legislation the EU's commitment to achieve net zero GHG emissions by 2050. The 2050 objective reflects commitments under the Paris Agreement and is central to the European Green Deal[21], published in December 2019, which sets out the Commission's commitment to tackling climate change and environmental challenges. To date, most SEE countries have relied heavily on conventional generation technologies. However, over the next decade, countries in this region will have to replace around 50% of their existing capacity for age-related reasons, according to a report by Agora Energiewende (5). However, renewable energy development in SE Europe has been limited until now.

One impediment to scaling up renewables is their higher up-front capital intensity, compared to investment in coal or natural gas. These costs make renewable energy investment more sensitive to political and regulatory conditions than projects with lower up-front capital intensity. And since private investors typically consider ventures in SE Europe riskier than investment in Germany or France, this kind of project in the region faces relatively higher financing and capital costs. The "risk premiums" demanded by investors have a significant effect on the price of renewable power. Past research has shown that higher financing costs could render a wind project in, for instance, Croatia, twice as expensive as the same project with similar resource conditions in Germany. Bloated financing costs thus have two effects: (a) they support the perception that renewables are costly to consumers and taxpayers and (b) they can render renewables incapable of outcompeting fossil-fired generation, even given cheaper system costs. (6)

Policy Inconsistencies Concerning Gas Use in SE Europe

If we take the EC's 2030 energy and climate policies at face value, there is a clear prejudice against any further investment in gas infrastructure in view of its full abandonment over the next 10-15 years and its substitution with hydrogen and RES. Meanwhile, all countries

[20] https://ec.europa.eu/info/files/commission-proposal-regulation-european-climate-law_en
[21] https://ec.europa.eu/info/files/communication-european-green-deal_en

in SE Europe have firm plans encouraging further gas use for power generation, industrial and commercial use and for domestic applications. Almost all governments in SE Europe consider gas as the fastest and most efficient way for decarbonisation, and its increased use is already evident in the region.

Hence, we are witnessing a strong inconsistency in SEE between pursued EU policy targets – with the EIB and EBRD already deciding against new gas infrastructure projects – and locally applied energy policies favouring gas use. Sooner or later, the EU will have to address this serious policy discrepancy and decide on strategy correction and associated medium- and long-term action plans. In other words, to what extent is Brussels willing to prohibit gas use and what alternative fuels is ready to propose?

It is no coincidence that last May, a group of eight EU members from the Balkans and eastern Europe joined forces to defend the "role of natural gas in a climate-neutral Europe" (7). In a joint paper, the group of eight calls for "combined electricity – gas solutions" in the transition to net-zero emissions by 2050. "A transition based solely on renewable energy sources does not consider the need for a diversified energy mix in the EU," says the paper. The paper – titled "The role of natural gas in a climate-neutral Europe" – is signed by a contiguous stack of countries, including south to north, Greece, Bulgaria, Romania, the Czech Republic, Slovakia, Hungary, Poland and Lithuania. It makes the case for gas in the transition away from coal power, which is a dominant form of electricity in many eastern EU member states. "When replacing solid fossil fuels, natural gas and other gaseous fuels such as bio-methane and decarbonised gases can reduce emissions significantly," the paper argues.

In late January 2021, the European Commission asked advisors to rework the EU's green finance taxonomy rules after member states rejected draft implementing guidelines, unhappy about the exclusion of gas as a "transition" activity towards net-zero emissions. (8)

In early February 2021, EU officials announced that the grants and loans provided to EU countries under the bloc's €750 billion Recovery and Resilience Fund will not automatically exclude funding for gas infrastructure as long as these projects are part of a coherent national decarbonisation strategy with clear milestones (9). The European Commission is currently preparing a "guidance document" on how to apply the so-called Do No Significant Harm (DNSH) principle, which applies to the entire Fund. Under that rule, EU money will be prevented from going to polluting technologies. The guidance document will explain "which kinds of conditions can be attached to gas investments" and make them "compatible with that principle".

Among the conditions are assurances that gas is part of a wider transition plan to renewables and guarantees that investments in gas facilities do not create a "lock-in" effect into fossil fuels – for instance, making sure that infrastructure is also suitable for the use of clean gases. All these must be part of a very clear and credible plan for decarbonisation, with clear milestones and deadlines, EU officials stressed. The European Commission reckons that clean electricity will meet 53% of the bloc's energy demand by 2050 as the bloc moves towards reducing emissions to net-zero. That leaves at least 40% for other energy carriers such as gaseous fuels that Brussels says will have to be fully decarbonised in order to reach the EU's stated goal of becoming climate-neutral by 2050. Natural gas has been a major driver of Europe's rapid transition away from coal power and is also proving a baseload back-up for variable renewable electricity generation from wind and solar power.

Discussion

The transition to decarbonised power generation is not an easy regional issue, since in most of the SEE countries electricity generation, which is mainly based on coal and lignite, supports thousands of jobs while it forms the basis of an extensive industrial base. Although all countries in the region to a greater or smaller extent are committed to RES and energy efficiency programmes and specific targets, they are also pursuing a parallel carbonisation agenda as several coal-fired power plants are under construction or at an advanced planning stage. In short, coal-based power generation is also moving ahead, adding substantial capacity from now until 2025 (1.5 GW per year for SEE and 2.5 GW for Turkey, i.e. total 4 GW per year over the next 7-8 years). New RES capacity over the last three-year period is less than 500 MW per year of installed capacity excluding Turkey, and approximately 1.5 GW per year including Turkey. As a result, there is a substantial gap between new coal-fired power plants and anticipated RES installations.

In addition to this RES supply gap, we must consider the likehood of a power generation shortfall as early as 2027. If that happens, the region will be transformed from an exporter of electricity to a net importer. This will drive up electricity prices. Underinvestment today and higher electricity prices in the near future will act as a brake to economic growth, fulfilling lacklustre performance forecasts for the region.

The road to decarbonisation can be approached on two levels: (a) through policy addressing the energy mix and assesseing the optimum rate of decarbonisation and investment in economic terms; and (b) through technology, whose penetration depends on the policies to be implemented and could contribute significantly towards decarbonisation. Good examples are the use of CCS/CCU or dual-fuel power plants, analysed by IENE in its "SE Europe Energy Outlook 2016-2017" study. (10)

The arduous and complex decarbonisation process in SEE is further burdened by a strong coal/lignite legacy and serious energy security issues. Rapidly increasing carbon prices and stricter EU regulations on air-polluters will bankrupt outdated lignite-fired power plants in the region over the next decade, making them politically untenable. Rising carbon prices will require ever bigger state subsidies for power plants, which is clearly not sustainable. Without these subsidies, fossil-based generation will make no economic sense.

References

(1) *London School of Economics (2020), "What is "decarbonisation" of the power sector? Why do we need to decarbonise the power sector in the UK?", http://www.lse.ac.uk/GranthamInstitute/faqs/what-is-decarbonisation-of-the-power-sector-why-do-we-need-to-decarbonise-the-power-sector-in-the-uk/*

(2) *Dempsey, H. (2019), "European coal plants forecast to lose €6.6bn in 2019", Financial Times, https://www.ft.com/content/ba190c72-f590-11e9-b018-3ef8794b17c6*

(3) *EndCoal (2020), "Global Coal Plant Tracker", https://endcoal.org/global-coal-plant-tracker/*

(4) *WWF (2019), "41 European mayors declare support for a just transition from coal", http://www.wwf.eu/?uNewsID=354315*

(5) *Buck, M., Risteska, S. and Redl, C. (2018), "A Clean-Energy Transition in Southeast Europe: Challenges, Options and Policy Priorities", Agora Energiewende, https://www.agora-energiewende.de/fileadmin2/Projekte/2018/Energiewendedialog_Suedosteuropa/Agora-Energiewende_Impulse_SEE_energy_transition_priorities.pdf*

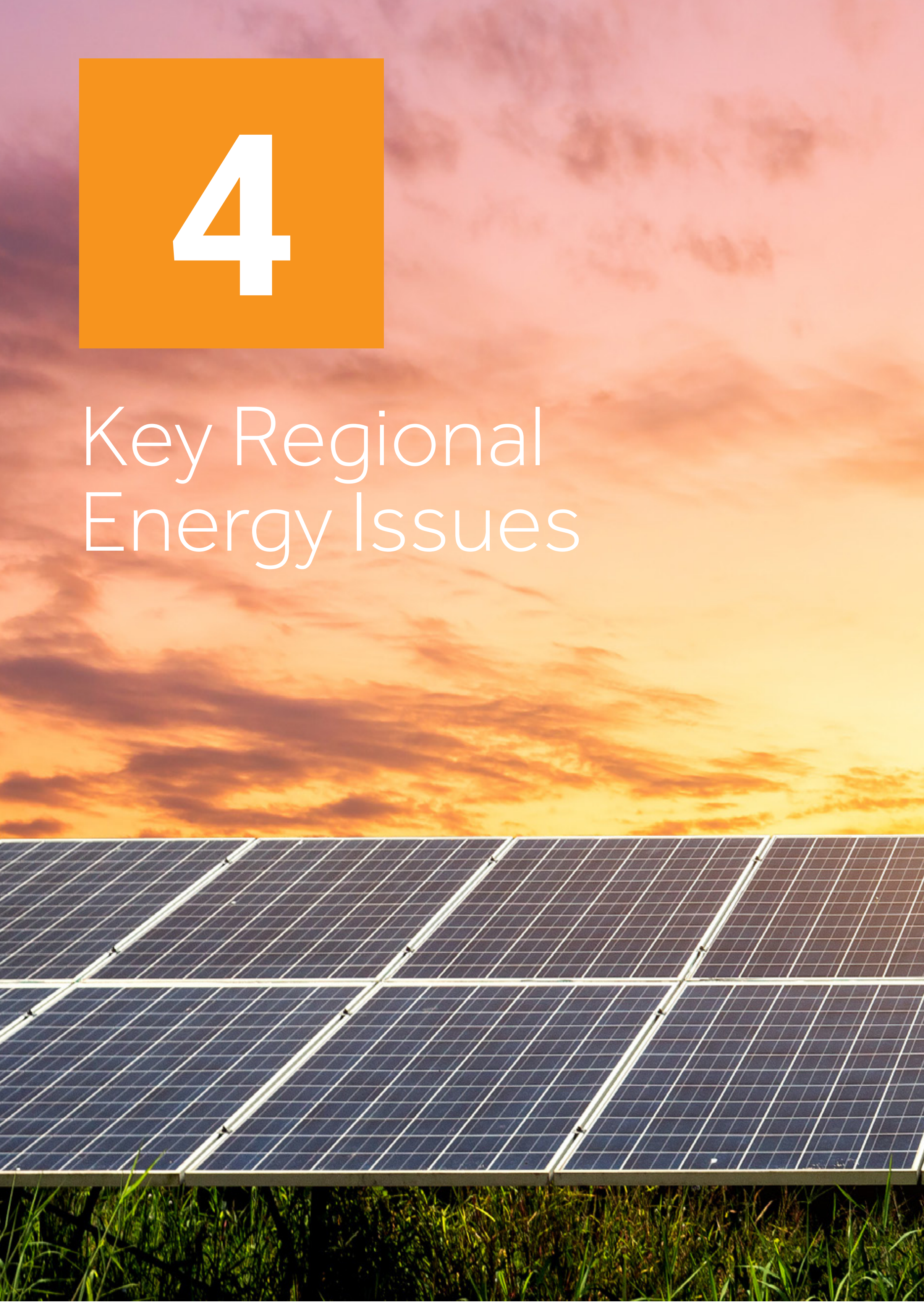
(6) *Lütkehermöller, K. et al. (2019), "Unlocking Low Cost Renewables in South East Europe", Agora Energiewende, https://newclimate.org/wp-content/uploads/2019/10/Unlocking_SEE.pdf*

(7) *Simon, F. (2020), "Eight EU states back 'natural gas' in net-zero transition", Euractiv, https://www.euractiv.com/section/energy-environment/news/exclusive-eight-eu-states-back-natural-gas-in-net-zero-transition/*

(8) *Simon, F. (2021a), "EU green finance advisors asked to clarify 'transition' to net-zero climate goal", Euractiv, https://www.euractiv.com/section/energy-environment/news/eu-green-finance-advisors-asked-to-clarify-transition-to-net-zero-climate-goal/1560091/*

(9) *Simon, F. (2021b), "EU does not exclude funding gas, highways under green recovery plan", Euractiv, https://www.euractiv.com/section/energy-environment/news/eu-does-not-exclude-funding-gas-highways-under-green-recovery-plan/*

(10) *IENE (2017), "SE Europe Energy Outlook 2016-2017", An IENE publication, Athens, 2017*



4

Key Regional Energy Issues

Key Regional Energy Issues

Before looking at SE Europe's core 15 countries (Chapter 5) and peripheral ones (Chapter 6), and before moving ahead to analyse the different energy sectors (Chapters 9-12), it is important to consider the big picture and become acquainted with the key issues which confront the region's energy sector.

These include the relatively high dependence of the majority of the countries on solid fuels, mostly used for power generation, high dependence on imported oil and gas, lack of adequate gas supply routes and interconnections (especially relevant for the main Balkan block), slow penetration of renewables and slow progress on energy efficiency improvement. Some of the inadequacies have clear geopolitical bearings, as we shall see.

The slow differentiation of the regional energy mix, which in spite of the rise of RES and gas penetration remains bound to high solid fuel consumption and sizeable oil imports, is no doubt a prime point of reference. The large amounts of indigenous coal and lignite deposits provide relatively cheap and easily accessible energy supplies for most countries of the region and hence are seen as preventing a determined move, by the European Commission and certain governments, towards decarbonisation. Hence, we have here a major policy challenge, which governments and the EC will have to address. Simply put, there is a huge incompatibility between stated and adopted EU goals for decarbonisation and the region's silent commitment to continuing large-scale solid fuel use.

Although several countries in the region appear determined to exhaust its coal/lignite deposits, they are in parallel developing renewables and other carbon free resources such as nuclear power. Given the financial and legal constraints in most countries, the rise of Renewable Energy Sources (RES), especially for electricity generation, over the last five years appears impressive. Yet because of the intermittent nature of power generation from RES and undeveloped large-scale energy storage, their contribution into the electricity production of the different countries appears limited. However, given the strong market dynamics of the RES sector, the introduction of viable large-scale storage schemes in the mid-term and hydrogen in the long-term are distinct options in the years ahead.

High oil and gas import reliance for most SEE countries stood at 87.50% on average for oil and petroleum products and at 80.28% on average for gas, on the strength of 2019 figures, with some countries reaching 100% dependence in both categories. This represents a small departure from the situation reported in IENE's 2017 "SEE Energy Outlook"[1]. Such high energy dependence is way above that of the EU-27, which on average stood at 58.2%. This means the state finances of several SE European countries are servient to the vagaries of international oil prices, as we have clearly seen in the period of 2010-2014, when the oil and gas import bill of most SE European countries ballooned to unprecedented levels, thus siphoning off much needed funds in order to meet basic transportation, heating and industry requirements. In other words, the then-prevailing high oil and gas prices prevented governments from channeling funds to development and social welfare projects, while condemning economic growth to zero or, in the best of cases, anemic rates. In view of oil price behavior in the H1 of 2021, with Brent oil above $70 per barrel, we might experience a similar situation in 2021/2022.

Another important regional issue concerns oil and gas exploration efforts and plans for future production. Most countries in SE Europe, in view of their great dependence on oil and gas imports, have over the years harbored plans and initiated long-term programmes aiming at the exploitation of their indigenous hydrocarbon potential (see Chapter 8). Now, in many cases,

[1] IENE (2017), "SEE Energy Outlook 2017", https://www.iene.gr/articlefiles/seeeo%202016-2017_iea%20paris.pdf

such plans have been seriously challenged following the double blow of the coronavirus (COVID-19) and the sharp fall of international oil prices in 2020 and the charge of EU's green policies.

On the one hand, the gloomy atmosphere in the global oil market, following NGOs' persistent calls for an end to hydrocarbon exploration activities and the rising geopolitical tensions present in the East Mediterranean have caused concern to international oil companies active in SE Europe. Questions arise about the viability of the companies that currently hold licensing blocks in the region, but also about the competitiveness of natural gas in an era of low prices (especially for LNG) and growing enmity against hydrocarbons in view of their implied negative environmental footprint.

In addition, natural gas, which is the fossil fuel with the lowest emissions, is facing another serious challenge by the narrow-confines of the EU Taxonomy (see Chapter 3). Hence, the decarbonization of the SE European region, without the use of natural gas, becomes an impossible equation thanks to EU's bureaucratic thinking, which appears to be completely cut-off from the harsh economic reality in the field in several SE European countries.

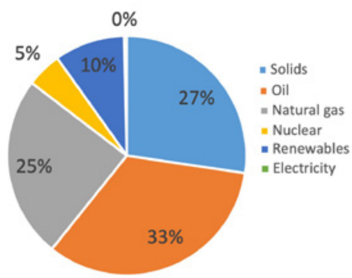
Other key challenges of the energy sector include the lack of adequate gas interconnections, which are preventing regional market development, since available gas quantities cannot be easily transported from one well supplied geographic area to another needy one. To a lesser extent, the region is in need of more and better electricity interconnections, something which is especially visible in island regions, such as Greece and Cyprus. Advancing international electricity interconnections especially between Italy and Western Balkans and between mainland Greece and the Israel-Cyprus-Crete axis is becoming a priority in view of the fast advancing electricity market integration in the region.

Since the publication of the last "SEE Energy Outlook" study in 2017, electricity markets in the region have progressed impressively with EU's Target Model now in place in most countries and markets coupled across the region. A detailed account of electricity markets is presented in Chapter 10.

4.1 The Glacial Change in the Region's Energy Mix

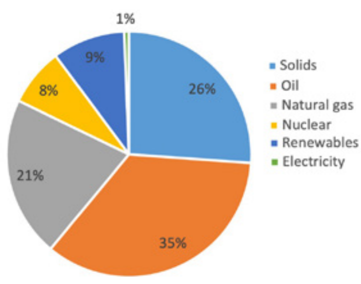
A key observation regarding the region's energy situation is related to its energy mix, taking into account all 14 countries (i.e. EU Member States, WB6 and Turkey). SE Europe's energy mix, with and without Turkey, is changing, albeit very slowly. In summary, between 2009 and 2019 (see Figures 4.1-4. 4) there is lower use of coal (lignite), gas and nuclear, more RES and almost the same level of oil, given the different total gross inland consumption. In a sense, this is disappointing given the huge emphasis placed over the past years on RES and the lowering of oil use.

Figure 4.1 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2009 (Total=263.6 Mtoe)**



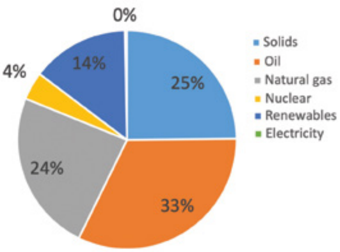
Source:Eurostat, IENE

Figure 4.2 **Gross Inland Consumption (%) in SE Europe, without Turkey, 2009 (Total=164.2 Mtoe)**



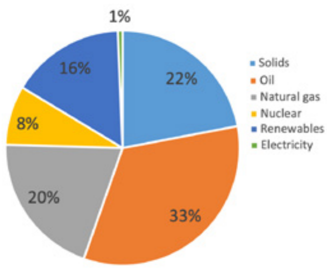
Source:Eurostat, IENE

Figure 4.3 **Gross Inland Consumption (%) in SE Europe, including Turkey, 2019 (Total=299.5 Mtoe)**



Source:Eurostat, IENE

Figure 4.4 **Gross Inland Consumption (%) in SE Europe, without Turkey, 2019 (Total=152.2 Mtoe)**



Source:Eurostat, IENE

Examining closer the regional energy mix between 2009 and 2019, a number of useful observations can be made:

(a) Over the last 10-year period, only a minor differentiation of the region's energy mix has taken place, both in the case where this includes Turkey and in the other that it does not.

(b) The most noticeable change is the increased contribution of renewables in both cases.

(c) The contribution of gas, although higher in both cases, remains marginal.

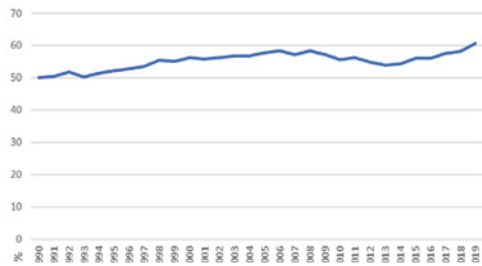
(d) There is clearly less use of solid fuels in both cases, but the retreat is not as big as anticipated so as to advance EU's decarbonisation agenda.

(e) Oil has an almost constant contribution to the overall energy mix as it covers almost 100% of transportation needs in all countries.

4.2 High Energy Import Dependence

In 2019, the energy dependence[2] of the EU-27 stood at 60.7%, the highest over the last decade. As illustrated in Figure 4.5, the evolution of EU-27 energy dependence has not been constant over 1990-2019; however, it has continuously stood above 50% since 1990.

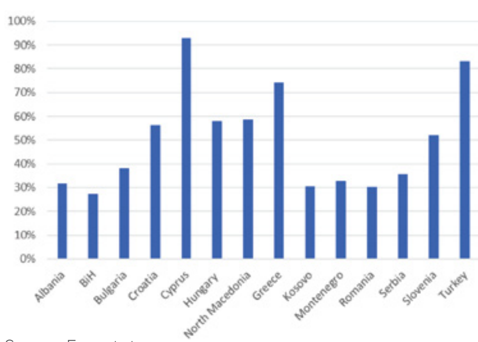
Figure 4.5 **Evolution of the EU Energy Dependence (%) over 1990-2019**



Source:Eurostat

Regarding SEE countries, energy dependence also varies significantly and averaged at 50.10% in 2019, taking into account the countries shown in Figure 4. 6. These figures are issued by Eurostat, along with the publication of the detailed 2019 annual results on energy supply, transformation and consumption in the EU.

Figure 4.6 **Energy Dependence (%) in SE Europe (2019)**

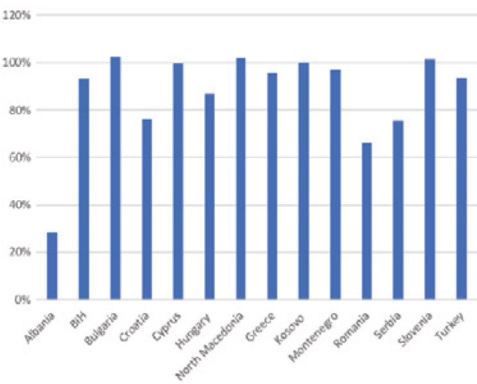


Source:Eurostat

2 The energy dependency rate shows the extent to which an economy relies upon imports in order to meet its energy needs. It is defined as net energy imports divided by gross inland energy consumption (which includes stock changes) plus fuel supplied to international maritime bunkers, expressed as percentage. A negative dependency rate indicates a net exporter of energy, while a dependency rate in excess of 100% relates to the build-up of stocks (Eurostat).

Eurostat also presents data for total oil and petroleum products, gas and solid fuels use separately for the SEE region in 2019. More specifically, almost all SEE countries (excluding Albania) relied more than 60% on oil and petroleum products imports in 2019, while Albania's dependence on total oil and petroleum products was about 28.3% (see Figure 4.7).

Figure 4.7 **Total Oil and Petroleum Products Dependence (%) in SE Europe (2019)**

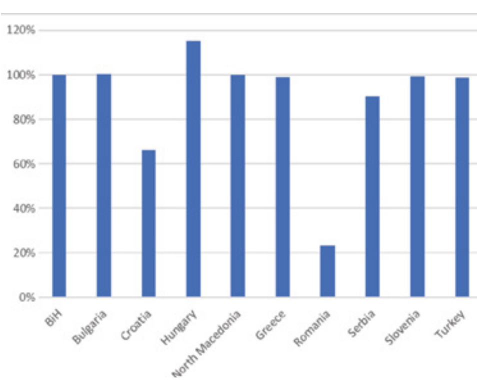


Notes: A dependency rate in excess of 100% relates to the build-up of stocks.

Source:Eurostat

Regarding gas, the majority of the SEE countries (excluding Romania) depended more than 60% on gas imports in 2019, while the gas dependence of Romania was about 23.3% (see Figure 4.8).

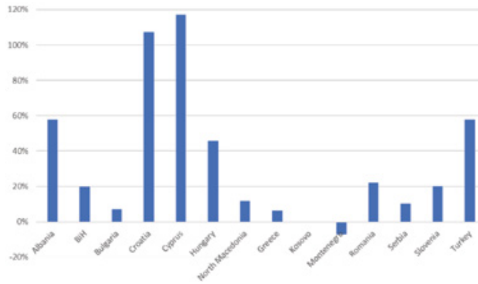
Figure 4.8 **Gas Dependence (%) in SE Europe (2019)**



Note: Albania, Kosovo, Cyprus and Montenegro do not import natural gas.
Source: Eurostat

In terms of solid fuels, only four SEE countries (i.e. Albania, Croatia, Cyprus and Turkey) depended more than 50% on solid fuel imports in 2019, while the solid fuel dependence of the remaining countries was lower than 50% (see Figure 4.9).

Figure 4.9 **Solid Fuels Dependence (%) in SE Europe (2019)**



Note: A negative dependency rate indicates a net exporter of energy. Source: Eurostat

Despite the fact that most of the SEE countries are highly dependent on oil and gas, which are widely used in the transport and household sectors, regional energy dependence is low, as the remaining energy used derives from hydropower and biomass, which are indigenous.

4.3 The Decarbonisation Challenge

As the EU moves towards committing to the decarbonisation of its economy to net-zero greenhouse gas (GHG) emissions by 2050, the SE European EU member states are still struggling with dysfunctional energy markets, blatantly inadequate long-term planning capabilities and an overwhelming dependence on fossil fuels. Combined, these factors represent significant impediments to decarbonisation objectives. The successful transition towards a low-carbon future in the EU relies on the resolution of these problems and the acknowledgement of the different starting points of the SEE EU member states in the decarbonisation process.

With the 'Clean energy for all Europeans' package[3], the Regulation on the Governance of

[3] https://ec.europa.eu/energy/topics/energy-strategy/clean-energy-all-europeans_en

the Energy Union introduced a new cooperation framework between member states and the European Commission, which requires rigorous and standardised national energy and climate planning. A novelty of this package is that binding targets will only be set at the EU level. Under this new mechanism, each member state is required to produce an integrated National Energy and Climate Plan (NECP) for 2021-2030, which will be updated once by 30 June 2024. Member states must also release progress reports, with the first one due in 2023. The plans must be written in a binding template in which governments must outline the actions and strategies to be pursued for each dimension of the Energy Union. Member states will also be obliged to consider the long-term 2050 perspective.

The long-term strategies should be revised every five years and updated every ten years. This framework provides both opportunities and challenges for all SEE countries. While the absence of binding national targets means that the new governance framework represents a 'softer' mechanism, it is not any less robust. The NECPs depend on national initiative and management of commitments, which can provide the needed flexibility for tailoring individual solutions. Moreover, by providing a binding template, the governance framework can trigger the development of rigorous national energy and climate planning, which has often been lacking in SE Europe.

At the same time, however, this new system may also lead to tensions between SE Europe, generally reluctant to take on aggressive decarbonisation, and the Northern and Western member states. If SE European countries perceive their energy systems and security of supply to be vulnerable, they are likely to adopt very defensive positions at the EU level to maintain strict control over their national energy mixes. This can lead to insufficiently ambitious NECPs, which may prove difficult to correct at a later stage. Hence, if the governance framework is to deliver on its objectives, the concerns of SEE member states cannot be ignored.

While more than half of the electricity generation capacity in SE Europe currently relies on thermal coal and lignite, a power system with a much higher deployment of renewable energy sources – as high as 50% by 2030 – has been shown to be realistic (1). This will require drastic changes in the status quo. While the need for strategic planning is evident, the energy transition will also rely on a mix of rigorous and ambitious policy design, access to diverse financial instruments for investments, as well as functional and transparent energy markets, accompanied by effective social protection for vulnerable energy consumers. Under these circumstances, one condition for a successful decarbonisation of the European economy is to understand the particularities of the EU member states in the SEE region as well as the Western Balkan countries in order to address specific problems with targeted policy and financial interventions. This requires increased attention and cooperation from both EU institutions and other member states.

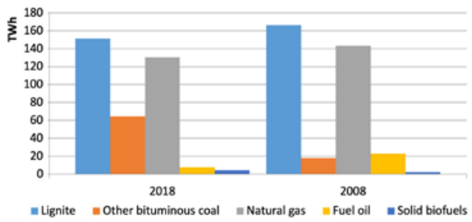
4.4 The Role of Gas

Based on data from ENTSO-e (2), gas-fired power generation in the EU was up by 6% in the fourth quarter of 2019, compared to the same period of 2018. In absolute terms, electricity generated from gas increased by 9.5 TWh on an annual basis. Gas-fired generation remained strong in Q4 2019; however, given the strong output in the first three quarters of the year, it showed less seasonality in 2019 than in earlier years. In Q4 2019, gas wholesale prices picked up in Europe, slowing down the increase in gas in the electricity sector. In 2019 as a whole, gas fired generation in the EU increased by 88 TWh (by 15%), and it represented 23% of the total EU power generation, up from 19.6% in 2018. (3)

At the same time, coal- and lignite-fired generation decreased by 25% in the EU, and its share fell to 14% in 2019 from 18.6% in 2018. Meanwhile, solar and wind generation was up, implying that gas and renewables kept on replacing solid fuels in the European electricity generation mix. Although carbon prices decreased slightly in Q4 2019, reaching almost €25/tCO_2e on average, the competitiveness of gas-fired electricity generation did not deteriorate measurably vis-à-vis coal, as electricity generation from gas is half as carbon intensive as that from coal.

In SE Europe, the majority of the gas and coal/lignite produced was used for gross power generation and as a source of heat for industry and buildings in 2018, as shown in Figure 4.10. During 2008-2018, we observe a parallel decrease of lignite and natural gas use on SE Europe's gross electricity generation.

Figure 4.10 **Gross Electricity Generation (TWh) by Type of Plant in SE Europe (2008 and 2018)**



Source: Eurostat

However, the future of natural gas seems ominous. The European Investment Bank (EIB) adopted new energy lending policies on November 14, 2019 (4), which aim at, among other things, gradually phasing out support for oil and natural gas production, gas infrastructure (networks, storage, refining facilities), and power generation technologies resulting in GHG emissions above 250g of CO_2 per kWh of electricity generated.

The EIB will continue to approve projects already under appraisal until the end of 2021. In addition, during this period, the Bank can approve gas infrastructure projects included under the 4th List of Projects of Common Interest (PCI) co-financed with the EU budget, which are deemed important to the European security of gas supply[4]. More information about policy inconsistencies concerning gas use in SE Europe to be found in Chapter 3.

4.5 The Role of Nuclear Power

In SE Europe, there are five countries (Bulgaria, Hungary, Romania, Slovenia and Croatia) that currently operate nuclear power plants (NPPs), while Turkey is expected to build no fewer than 3 NPPs over the next decade. Nuclear power, although it covered only 4.0% of the gross inland consumption in SE Europe in 2018, remains a viable option for growth because it offers important baseload capacity and supports the EU's decarbonization policies. The zero emissions from operating NPPs contribute to the region's efforts to curtail GHG emissions. This means that nuclear energy has an important role to play in the SE European energy and electricity mix over the next decades.

Following the tragic accident at Fukushima's NPP in March 2011 and operational security reviews, which have since been conducted by the SEE countries that host NPPs, the use of nuclear power in the region is unlikely to diminish over the next decade. Neither Bulgaria nor Romania nor Hungary are likely to shut down the Cernavoda, Kozloduy 5-6 and Paks 1, 2, 3, and 4 power plants respectively on account of safety concerns.

The same applies for Croatia and Slovenia, which, between them, share the Krško NPP. Both governments are very well aware of the fact that a decrease in the participation of nuclear power in their electricity generated portfolio cannot be easily replaced by renewables or be compensated by an increase of coal generated electricity due to the equally burdensome environmental costs. If they are to reduce the participation of nuclear power in their total electricity mix, both states have as an alternative the increase of imported gas, magnifying their already high dependence on gas.

[4] On February 12, 2020, the European Parliament adopted the 4th list of PCIs, including 32 gas, 6 oil and 5 CO_2 network projects: https://bernardenergy.com/lastestdevelopments/ep-adopts-fourth-list-projects-common-interest/

Theoretically, the participation of nuclear generation in the regional electricity mix is set to diminish significantly as the rising demand of Bulgaria and Romania will be covered by increased volumes of natural gas and, to a lesser extent, renewables. However, this might change as both Romania and Turkey are definitely going ahead with plans to increase their nuclear installed capacity, which will result in two major nuclear power generation complexes with 6 GW of new installed capacity to be operated by 2030.

In the cases of Bulgaria (Units 5 and 6 and the planned Unit 7 of Kozloduy NPP) and Turkey (the Akkuyu site), Russia might have a role to play. However, it should be recalled that strategic investments have two substantial characteristics in the energy sector. They need many years to be implemented but they last for decades. Such long-term planning should not be subverted by short-term political priorities against regional, economic and safety considerations.

In this sense, the Fukushima anti-nuclear rationale does not appear to hold in the case of SE Europe. For countries already involved in nuclear power development (i.e. Bulgaria, Romania, Hungary, Croatia/Slovenia, Turkey), the road ahead is unlikely to be obstructed by revised risk assessments.

Developing further nuclear power generation in the region will be a real challenge as not all countries favour this option. Detailed studies need to be undertaken to identify the real potential pitfalls of nuclear energy and to assess the compatibility of nuclear and RES power in the context of decarbonization.

According to a leaked document, as cited by Euractiv (5), experts tasked with assessing whether the European Union should label nuclear power as a green investment will say that the fuel qualifies as sustainable. The European Commission is attempting to complete its sustainable finance taxonomy, which will decide which economic activities can be labeled as a sustainable investment in the EU, based on whether they meet strict environmental criteria. EU experts last year were split over whether nuclear power deserved a green label, recognising that while it produces very low CO_2 emissions, more analysis was needed on the environmental impact of radioactive waste disposal.

According to Reuters (6), the European Commission asked the Joint Research Centre (JRC), its scientific expert arm, to report on the issue. A draft of the JRC report said that nuclear power deserves a green label. "The analyses did not reveal any science-based evidence that nuclear energy does more harm to human health or to the environment than other electricity production technologies", it said. Storage of nuclear waste in deep geologic formations is deemed "appropriate and safe", it said, citing countries including France and Finland in the advanced stages of developing such sites.

Two expert committees will scrutinize the JRC's findings for three months before the European Commission takes a final decision. EU countries are split over nuclear power. France, Hungary and five other countries in March 2021 urged the Commission to support it, while other states oppose it.

4.6 RES as a Key Supply Source

SE Europe's RES potential

Better interconnections, a higher share of RES and better energy efficiency, are some ways to address SE Europe's energy dependence. In terms of RES, SE Europe has abundant resources, and their use is already part of many people's daily lives. Thanks to considerable installed hydropower capacity and the extensive use of biomass for residential heating, the SEE economies use a higher proportion of RES than the EU average (7). n fact, despite having an installed hydropower capacity of more than 22 GW, the SEE region still has the largest remaining unexploited hydropower potential in Europe, as its river catchments have remained largely undeveloped. The technical potential of hydropower is estimated to be 522 PJ per year, as shown in Table 4.1.

While up to 140 large (above 10 MW capacity) greenfield hydropower plants and more than 2,700 small projects (below 10 MW capacity) are in the production pipeline, the sustainability of these projects has sometimes been questioned. In the last couple of years, opposition to the construction of small hydropower plants has been growing, mainly in Albania, Bosnia and Herzegovina, Croatia and Serbia. Local stakeholders and non-governmental organisations (NGOs) have called for a set of principles for sustainable hydropower to be respected, with one of these principles being the prioritisation of investment in rehabilitating existing plants.

Table 4.1 **Technical Potential for Utility-scale Solar PV, Wind and Hydropower in the Electricity Sector in SE Europe (TJ)**

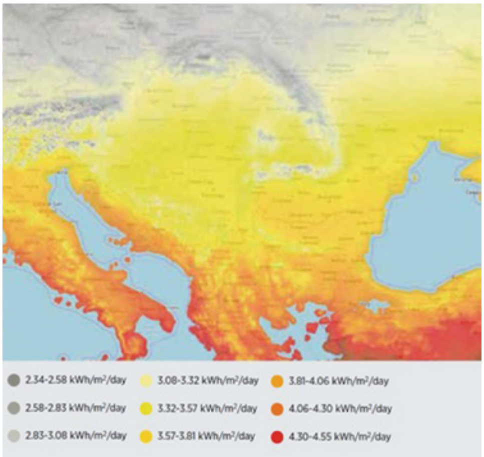
	Utility-scale solar PV	Onshore wind	Hydropower
Albania	13 342	49 154	56 059
Bosnia and Herzegovina	14 886	94 810	88 193
Bulgaria	36 468	190 264	48 071
Croatia	15 682	104 951	30 600
Kosovo*	3 006	13 860	4 853
Montenegro	3 874	23 332	18 079
North Macedonia	8 014	27 558	14 421
Republic of Moldova	21 758	180 450	12 099
Romania	92 902	554 522	136 800
Serbia	33 509	188 590	64 800
Slovenia	1 613	8 266	58 539
SEE	245 052	1 436 156	532 515

TJ = Terajoule

Source: IRENA

Global horizontal irradiance, a key parameter in solar PV installation, is higher in the southern part of the region, where it reaches over 4.5 kWh per square metre per day (kWh/m2/day). Solar resources in the northern part are more modest, down to 3 kWh/m^2/day, but in line with or better than other European countries with large PV deployment, such as Germany (see Map 4.1). The utility-scale solar technical potential of the SEE region is estimated at around 245 PJ (see Table 4.1).

Map 4.1 **Solar Resources in the SEE Region and Surrounding Countries**

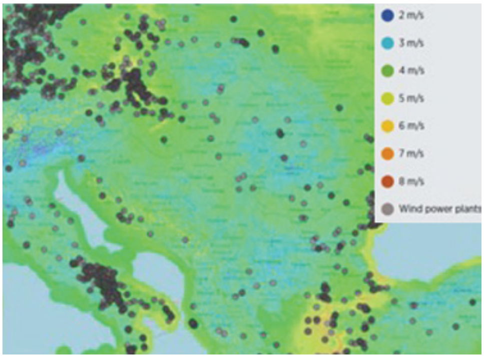


Source: IRENA

The whole region is endowed with good wind resources, with wind blowing at average speeds of between 5.5 metres per second (m/s), and 7 m/s at 100 metre height. The mountainous and coastal landscape increases the variation in wind resources across the region, with higher average wind speeds in coastal areas and at high altitudes. The Eastern coast of the region (i.e. Romania) enjoys the best wind, with average speeds of 6-to-7 m/s (see Map 4.2).

The Adriatic coast (i.e. Albania, Bosnia and Herzegovina, Croatia, Montenegro and Slovenia) enjoys similar average wind speeds, but this area is also regularly hit by winds that gust between 150 and 200 kilometres per hour. This puts additional stress on wind turbines. However, wind energy is not harvested at its full potential, as in nearby countries with similar wind resources, with the exception of the EU member states of the region. The technical potential of SEE's wind energy is currently estimated at 1,436 PJ (see Table 4.1). Notably, the presence of a good technical potential is a necessary but not sufficient condition for deployment. Other aspects to consider are the economic limits to supply, market constraints and the presence of appropriate supply chains.

Map 4.2 **Wind Speed and Wind Power Plants in the SEE Region and Surrounding Countries**



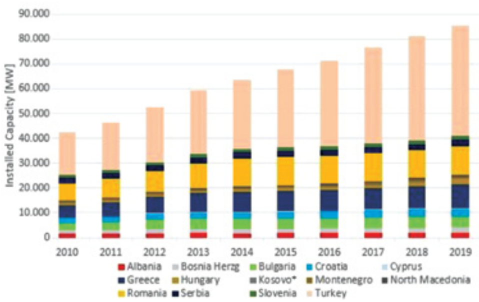
Source: IRENA

RES Increased their Share in SE Europe's Electricity Mix

The total installed RES capacity in SE Europe doubled during the past decade, with local systems exceeding 85.56 GW of installed capacity in 2019, according to IENE. This represents an increase of 100.5% since 2010, when the region counted 42.68 GW of installed RES units. In addition, the power generation from RES, including hydro, stood at 199.2 TWh in 2018. This corresponds to a 40% increase over the last decade.

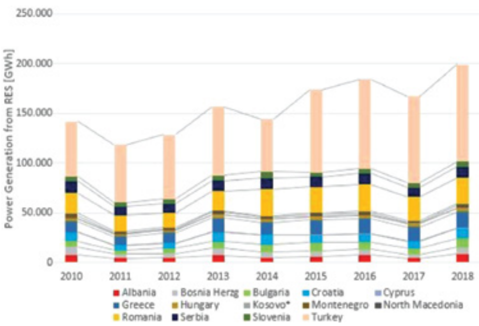
It should be noted that electricity generation from RES in the SEE region is heavily affected by the hydrologic cycle, which has shown signs of heavy volatility throughout the decade. Most notably the region was affected by drought especially during 2011, 2014 and 2017, when it halted the increase of y-y generation from RES, despite the increased deployment of other RES systems, mainly wind and solar. The most affected countries by the hydrologic cycle were Turkey, Croatia, Albania and Bosnia and Herzegovina. The most widely deployed renewables are by far in Turkey, which has an RES fleet, which consists mostly of hydro and wind, with a considerable capacity of geothermal energy. In 2020, Turkey's total installed RES capacity exceeded 44.5 GW. Turkey is followed by Romania and Greece, with installed RES capacity of 11.2 GW and 9.8 GW respectively.

Figure 4.11 **Total Installed RES Capacity (MW) by Country in SE Europe (2010-2019)**



Source: IRENA

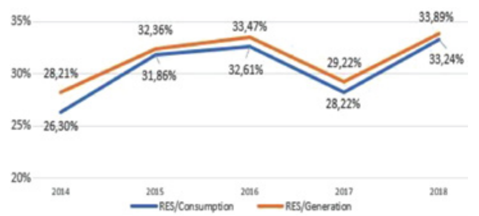
Figure 4.12 **Power Generation (GWh) from RES, Including Hydro, in SE Europe (2010-2019)**



Source: IRENA

Moreover, RES units have increased their regional share in power generation to 33.89% in 2019, i.e. by more than 5.5 percentage points compared to 2014, when they contributed 28.2%. In addition, in 2019, the share of RES in total regional electricity consumption rose to 33.2% from 26.3% in 2014.

Figure 4.13 **Share (%) of RES in Total Regional Consumption and Regional Power Generation in SE Europe (2014-2019)**



Sources: IRENA, ENTSOe, ERE, IENE

As RES have already been recognized as one of the most important resources in mitigating climate change, the global market is amidst an ongoing ramping up of RES installations. Falling production costs of variable renewables systems have fallen rapidly during the past decade, driving an escalation in the deployment of competitive solar PV and wind turbines across the region. The deployment of variable renewables is more evident in more mature markets, such as Turkey and Greece, which have increased their RES penetration impressively, marking annual increases in their installed RES capacity by 5.6% and 8.7% in 2019 respectively.

4.7 Energy Efficiency as a Champion Energy Source

On October 10, 2020, the European Commission adopted "An Economic and Investment Plan for the Western Balkans" (8), which identified flagship initiatives related to clean energy and the transition from coal. An overall budget of €9 billion during 2021-2027 is proposed for the Plan's implementation, of which a fair share is expected to finance building renovation and decarbonisation of the heating and cooling sectors.

The Plan relies on support from the Energy Community Secretariat to implement the Renovation Wave. In this respect, its role may be manifold. The Secretariat offers its assistance to the Western Balkan Contracting Parties in improving the legal framework and removing regulatory barriers in the building sector; facilitating information sharing and exchanging best practices; and serving as a bridge between the providers of technical and financial assistance and beneficiaries.

In contrast to the Western Balkan countries, the EU has already acquired extensive experience in implementing financial and fiscal instruments to support building renovations. These instruments have different sources of finance, delivery mechanisms and approaches, and are available to more sectors, including residential, commercial and Small and Medium sized Enterprises (SMEs). In the EU, only in the last four years, the Joint Research Centre[5] identified a total of 129 ongoing public financial and fiscal schemes supporting energy renovations, of which around 61% are in the form of grants and subsidies, 19% are soft loans, 10% are tax incentives and the remaining 10% a combination of the above. The same study showed that around €15 billion are being spent annually across the EU for energy efficiency in public and non-public buildings. The majority of the instruments applied in the residential sector in the EU Member States are based on grants and subsidies, traditional loans and soft loans and fiscal incentives.

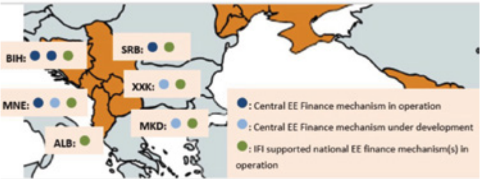
Despite the many instruments at hand, the renovation of buildings in the EU has proved to be very difficult and quite slow, compared to expectations. Presently only 1% of buildings undergo energy efficient renovation every year, while about 75% of the building stock is considered energy-inefficient. In the Energy Community, the renovation process is even less advanced.

In the Western Balkans, it is estimated that approximately €1.06 billion were invested in energy efficiency projects in all building categories between 2010 and 2020, based on Energy Community Secretariat calculations (9). The figure is significantly lower in the residential sector, which due to the many barriers is considered a difficult market to serve as it is fragmented, with small-scale investments, and riskier than the other building categories.

With the support of donor engagement in energy efficiency projects, many Western Balkan countries have established, or are in the process of establishing, centralised energy efficiency financing mechanisms. These are complemented by multi-country initiatives supported by International Financial Institutions (IFIs), as shown in Map 4.3.

[5] Joint Research Centre (2019), "Accelerating energy renovation investments in buildings – Financial and fiscal instruments across Europe", https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/accelerating-energy-renovation-investments-buildings

Map 4.3 **Overview of Centralised Energy Efficiency Financing Mechanisms in the Western Balkans**



Sources: Energy Community Secretariat

One category is represented by multi beneficiary programmes, mostly funded by loans from IFIs with incentives and technical support provided by the European Union. However, despite the large number of regional energy efficiency credit lines (supported by IFIs and the EU) available to help improve energy efficiency in residential buildings in the Western Balkans, their uptake has remained modest and focused on high income segments and those living in detached houses.

The building sector accounts for over 40% of total energy consumption in the Western Balkans. Renovating public and private buildings to meet minimal energy performance standards can make a very significant contribution to the reduction of GHG emissions, improve living standards and health. A building Renovation Wave implemented with the help of the Energy Community will assist the Western Balkans and SE Europe in general in decarbonizing public and private building stock, with a strong emphasis on digitalisation and taking into account energy poverty. The EU, together with international financing institutions, will support the efforts of the Western Balkans partners to triple the current renovation rate and energy savings in existing buildings and achieving nearly-zero energy and emission standard in new buildings.

4.8 Energy Market Liberalization and Integration in SE Europe

Ever since the EU set up the process of developing the internal market, the energy sector and especially the electricity sector have monopolised the EC's attention. It has taken more than 20 years of persistent efforts and countless disagreements and legal cases with incumbent electricity authorities for the European Commission to manage the transition from state control of the electricity sector to an open and market-oriented system with competition among producers, suppliers and distributors. In SE Europe, this liberalisation process was fraught with difficulties and numerous non-technical obstacles, as the incumbent companies in almost all countries solidly resisting change in order to maintain market control and hence political influence.
Several years later, the situation in EU member countries and Turkey looks very different, with certain countries having managed to complete what appeared to be an anomalous transition period. In the case of Turkey, the progress achieved in electricity market unbundling and retail competition has been highly successful, with the market opening up much faster than anticipated. In the case of the Western Balkans, we have the intervention of an EU institution, the Energy Community, through the contracting parties, which has facilitated the overall transition process and acceptance of the European Acquis. Hence, some solid steps have been made towards electricity market competition. However, progress is not very satisfactory in most contracting parties, largely because of the inflexible market structure and the stiff hold of the state over market mechanisms.

Due to the increasing significance of having a secure electricity supply and its positive impact on the environment and society, the energy sector in SE Europe is characterized by vertically integrated natural monopolies. If one also takes into account that the energy sector has long been highly regulated, it is easy to see why electricity and gas markets have high operating costs and high retail prices, along with costly large-scale investments, low-quality services and lack of competition in supply and generation.

Reforms in several countries in SEE have already been implemented in order to generate electricity within actual marginal production costs. However, distribution and transmission services are expected to remain natural monopolies as they satisfy security of supply.

Furthermore, there is a kind of dilemma between bilateral trading and power exchange-based markets in terms of competition. Despite the fact that bilateral markets are more flexible than the exchanges, their negotiation procedure can be expensive, while exchanges provide higher security for market participants, lower trading costs, increased competition and full transparency. As the number of players in the electricity market of each country in SEE region increases, the higher the competition becomes. Several countries have already established an energy market and enjoy its benefits.

Indicatively, in the electricity sector of Bosnia and Herzegovina, there is no competition and no electricity trading platform, Albania and Kosovo have already signed an agreement to establish a joint power exchange, known as APEX, while competition in the Croatian market is very limited as it trades bilaterally. In Montenegro, the wholesale market is open for competition, including the balancing market, except for the balancing reserve.

In general, the SE European electricity markets can be characterized by the following issues: (a) only basic steps in the electricity market procedures were realized by the majority of the countries, (b) cross-border power trading has until now been based on bilateral agreements between countries, (c) market coupling especially via the flow-based approach has not yet been fully implemented, and (d) the transmission network in the SEE region seems to have different characteristics in comparison with the Central and Western European meshed grid, where market coupling procedures are more mature. The main challenge for the economies of SE Europe is to commit to and insist on the implementation of long-term reforms that will target competitiveness and better integration among the EU member states of the region, their neighbors, candidate countries and potential candidate countries. Such reforms in the economy are likely to have a direct and positive impact on the further development of energy markets and the creation of favourable conditions in attracting suitable outside investment.

In this edition of "SE Europe Energy Outlook", we have placed equal emphasis on gas market liberalisation since gas, supported through a number of policy measures related to the EU's climate change targets, is poised to penetrate further into the energy mix of most countries, despite some recent policy measures against it. Where do we stand on deregulation and how far are the various national markets are opening up to competition?

The real progress achieved in the gas markets of SE Europe during the last decade is rather poor. The nature of gas markets in the region remains predominantly national, with very little, if any, cross border trade taking place, other than that implemented through the long term supply agreements national incumbents have with their traditional suppliers.

With the exception of Croatia and Romania, whose indigenous production covers almost 60% and 80% of their domestic demand respectively, all other SEE countries that have a gas market are solely depending on Russian imports. Albania, Montenegro, Kosovo and Cyprus still have no gas market, while only Greece, Croatia and Turkey possess LNG gasification terminals, representing the only LNG import points in the whole region.

In addition, the whole region is characterized by the lack of sufficient interconnectors, which would allow the development of gas trade between the countries. In practice, the only pipelines that link the countries of the region are the traditional transit pipelines, which have been developed to serve the long-term contracts signed several decades ago, mainly in implementation of Intergovernmental Agreements (IGAs). In most of the cases, these pipelines are subject to long-term capacity reservation through ship-or-pay transit contracts. The validity of all those transit agreements, concluded before countries such as Romania and Bulgaria joined the EU, supersedes the legal obligations arising from the European Acquis on energy. Therefore, access to these pipelines is, in principle, prohibited until the Intergovernmental Agreements expire.

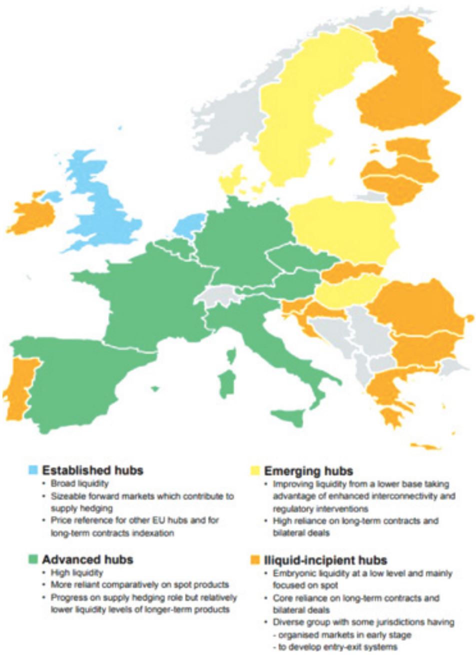
Over the last two years, the only important gas infrastructure developments in SE Europe included the operation of the Turkish Stream pipeline and TAP. Turkish Stream connects Russia with Turkey across the Black Sea. On January 18, 2020, the opening ceremony was held, marking the first deliveries of gas to Turkey. On January 27, 2020, 1 bcm of natural gas was delivered via the pipeline.

In addition, according to an announcement by Bulgartransgaz, Russian gas for Bulgaria, Greece and North Macedonia is now delivered via Turkish Stream, which crosses the Bulgaria - Turkey border. In practice, this means that as of early January 2020 Gazprom, by delivering gas via the Turkish Stream pipeline, has fully replaced the route that passed through Ukraine and Romania via the Soviet-era Trans-Balkan Pipeline.

The Trans-Adriatic Pipeline (TAP), forms part of the Southern Gas Corridor, which transports natural gas to Europe from the Shah Deniz II field in Azerbaijan. Commercial operation began on November 15, 2020. TAP AG, its builder, owner and operator, confirmed the commencement of gas flows from Azerbaijan on December 31, 2020. The first gas volumes reached Greece and Bulgaria via the Nea Mesimvria interconnection point with Greece's DESFA, as well as Italy, via the Melendugno interconnection point with Italy's SNAM Rete Gas.

As it is evident from the above analysis and Map 4.4, we are still facing a highly fragmented landscape for gas market development in SE Europe, with effectively no cross border trading as yet, which is very difficult to support the development of competition and of liquid market trading, despite the high interest of several SEE countries in becoming gas trading hubs[6]. In this environment, it is too difficult to imagine how the pan-European vision of a Gas Target Model would be implemented in a reasonable time frame. Some analyses show that, despite this market fragmentation, there are elements of national gas market legislation and regulation that would allow gas trading as performed in the more mature gas hubs of Europe and the US.

Map 4.4 **Ranking of EU and UK Hubs Based on Monitoring Results – 2020**



Sources: ACER[7]

This reveals that the only way forward for the appropriate development of the gas market in the region is the consistent and rapid implementation of the provisions of the Third Energy Package, at least to the extent that the countries have committed to implement it in a legally binding way, i.e. the EU Member States and the Energy Community Contracting Parties. Turkey's plans are rather ambiguous. It is making efforts to enhance competition domestically, at least at the level of wholesale supply and, to some extent, retail. However, Turkey reveals a scepticism in implementing radical legal reforms that would allow its gas market, which is by far the largest and most dynamic in the region, to genuinely open to competition from the outside, by, for example,

[6] IENE (2019), "Prospects for the Establishment of Gas Trading Hubs in SE Europe", IENE Study M49, https://www.iene.eu/articlefiles/working%20paper%20no28.pdf

[7] ACER (2021), "Market Monitoring Report 2020 – Gas Wholesale Markets Volume", https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202020%20-%20Gas%20Wholesale%20Markets%20Volume.pdf

joining the Energy Community or, as an alternative, implementing crucial parts of the legislation for market liberalisation to which most of the countries in the region have already committed.

4.9 The Energy Security Dimension

The energy sector and pursued policies and strategies may be analysed through different angles - economic, environmental and geopolitical. The geopolitical approach to energy emphasises energy security, which in most cases appears to dominate energy policy. This stands in contrast to the economic or environmental approaches, which prioritise sustainability and competitiveness. Energy security priorities are perceived both in terms of supply routes and origin of resources. The geopolitical approach primarily considers the geographical position of a particular country or region from the perspective of the location of the energy resources and how this affects the other parameters. These normally include access, the actors that control resources, their price, existing and alternative transport routes, relations with the regional and global markets, market mechanisms and the regulatory framework that may influence suppliers and marketeers, the availability and management of these energy resources, as well as political decisions and the manner and framework within which they are made.

Although most countries aspire to the lowest possible energy dependence and the maximum use of their indigenous energy resources, whether mineral or renewables, this is not always possible, either due to lack of mineral resources (oil, gas, solid fuels) or of finances. This is often the case where a long-term import deal (e.g. for oil and gas) is preferable in economic terms to the development of local mineral resources. However, in certain cases where a country's sovereignty is at stake and the inland or seaborne transport of energy supplies is vulnerable to enemy action, then, despite the high cost, it is preferable to aim for indigenous energy source exploitation (such was the case in Nazi Germany with the local production of synthetic oil from coal using the hydrogeneration process[8]). Putting for a moment aside the energy security dimension, we observe that countries, which have managed to take advantage of their indigenous mineral energy resources, produce oil and gas, much more cheaply and have an advantage when it comes to the domestic market, where they can achieve competitive prices, or aim towards exports to secure valuable income.

Table 4.2 **Energy Dependence (%) in Europe, 2019**

GEO	2019
European Union - 27 countries	60.704
European Union - 28 countries	57.859
Euro area - 19 countries	65.316
Belgium	76.676
Bulgaria	38.102
Czechia	40.894
Denmark	38.781
Germany	67.610
Estonia	4.829
Ireland	68.395
Greece	74.110
Spain	74.955
France	47.595
Croatia	56.224
Italy	77.484
Cyprus	92.805
Latvia	43.963
Lithuania	75.217
Luxembourg	95.129
Hungary	69.704
Malta	97.172
Netherlands	64.721
Austria	71.727
Poland	46.818
Portugal	73.848
Romania	30.371
Slovenia	52.140
Slovakia	69.762
Finland	42.092
Sweden	30.244
Iceland	16.106
Norway	-575.260

Sources: Eurostat

In Europe, and this applies largely to SE Europe, because of the long peace period the region has enjoyed since WWII, many countries placed energy security as a secondary priority. Their primary concern was market development and delivering affordable energy, whether electricity or oil, to as many people as possible. It was only after the war in Yugoslavia in the 1990's and the assertiveness of energy rich Russia following the collapse of the Soviet Union that energy security started to become a major priority of strategic planning.

[8] Yergin, D. (2008), "The Prize: The Epic Quest for Oil, Money & Power", Free Press; Reissue edition

With several countries in the region until very recently relying entirely on Russian gas imports, there was a major drive soon after the turn of the century to seek alternatives. Under much pressure from the EU, the South Corridor was developed along with a number of new LNG import terminals and cross-border interconnections. However, the region still remains vulnerable due to the limited number of suppliers and to even fewer supply routes.

SE Europe and the Western Balkans

With the exception of Albania, the countries of SE Europe depend on Russia for their oil and gas supply, while Kosovo and Montenegro have no gas infrastructure at all. Particularly interesting from the geopolitical perspective, given the fixed nature of transport routes and their potential vulnerability to political conflicts or other security hazards, is gas supply. Even though the Western Balkans countries are minor consumers of gas, which accounts for only 6% of their total energy consumption, there is a number of projects and initiatives aimed at diversifying the region's energy sources and supply routes. At the moment, no country in the Western Balkans has diversified sources or supply routes when it comes to natural gas. (In the case of oil, we have a different situation since apart from a limited number of pipelines, oil is delivered freely by ship or tracks through several entry points).

In Chapter 9.2, there is a detailed analysis of existing and planned major gas pipelines (e.g. TANAP-TAP system, IGB, IGNM, IAP, Turkish Stream, BRUA, etc.) that would allow the countries of the SEE region to diversify their gas supply sources and routes, which would in turn result in lower prices and stimulate the further development of gas infrastructure in the region.

In Western Balkans, Serbia has the most developed gas infrastructure, while the gas markets in Bosnia and Herzegovina and North Macedonia are very limited. In the rest of the SEE region, Turkey is the country with the most extensive and well developed gas network, followed by Greece.

Both countries are totally dependent on Russian and Azeri gas imports via pipeline but also from substantial LNG quantities.

The Western Balkans and SE Europe in general remain a poorly connected region in terms of energy infrastructure, with almost secluded energy markets often burdened by political instability. The region will continue to face three fundamental challenges. The first concerns insufficient investment in energy infrastructure, addressed by the EU's energy and climate targets for 2030. The second is the lack of clear and enforceable measures to ensure the preparedness of energy systems and their response to potential shocks in the event of an interruption to gas or oil supplies or other types of energy shock (e.g. electricity grid problems). The third challenge is reflected in the activities of external actors, who exploit clientelism of political elites in the region in order to oppose the implementation of EU policies as exemplified by the Energy Community goals in Western Balkans countries.

This last challenge is exacerbated by divergent conceptual understandings of energy security among countries in the region, on the one hand, and the EU, on the other. Countries tend to prioritise availability of resources, investments, or loans for the energy sector without any required reforms The EU promotes energy transition, transparency and investments tied to specific reform requirements.

Geopolitical Dilemmas

In stark contrast to the furor caused by the Nord Stream 2 gas pipeline, following the imposition of sanctions - since lifted - by the US, going back to 2018, when the project was launched, TurkStream, which brings Russian gas to Turkey via the Black Sea, and from there to the rest of SEE bypassing Ukraine, has elicited no such sanctions. Hence, from January 2020, gas supplied to the region by Gazprom is now delivered exclusively via Turkey to Bulgaria, Greece, North Macedonia, Serbia, Bosnia and Herzegovina, and will soon flow to Hungary and from there to Austria.

Construction of the TurkStream pipeline started in early 2017 and was completed at the end of 2019 with first gas deliveries to Turkey taking place on January 1, 2020. Turkstream replaced SouthStream, which had been designed to land in Bulgaria. Strong EU and US pressure on the Bulgarian government led to the pipeline's cancellation in December 2014.

TurkStream runs 930 km across the Black Sea from Anapa in the Russian Caucasus to Kiyikoy, west of Istanbul. It has a total capacity of 31.5 bcm per year through its two strings, with almost half of the quantities destined for the domestic Turkish market[9]. In essence, TurkStream has replaced completely the Soviet-era Trans Balkan Pipeline in operation since 1988, which has been piping Russian gas to Turkey, Greece, Bulgaria, Romania and Moldova originating in Ukraine. Since the start of TurkStream's operation, Ukraine has lost revenue estimated at $2.5 billion annually from the loss of transit fees for some 20 bcm of Russian gas per year[10, 11].

The timely completion and operation of TurkStream contrasts starkly with delays in the construction of Nord Stream 2[12], which suffered strong reactions from Eastern European countries that are EU members. Nord Stream 2 is slated for operation before the end of 2021[13], two years later than its sister pipeline. Nonetheless, Moscow's original strategic plan to completely bypass Ukraine appears to be coming to completion. Thus, a total of 142 bcm of Russian gas could be delivered to the main European markets and SEE through a combination of the Nord Stream complex (Nord Stream 1+2) and TurkStream, roughly corresponding to 80% of annual average Russian gas deliveries to Europe. This grand Ukraine circumnavigation plan, devised by the Kremlin, owes its origin to Ukraine's defiance of Moscow's commercial commitments, in the crises of the winters of 2006 and 2009, when Kiev suspended forward shipment of Russian transiting gas quantities destined for European clients in order to serve its own needs. To that, one should also add mounting disagreement at the time over transit fees and the cost of Russian gas purchased by Ukraine to cover its own needs[14].

Although the financial damage TurkStream inflicted on Ukraine is significant, there was hardly any reaction or fierce representations to Ankara or Moscow by Kiev or Washington, at least at the scale witnessed in the case of Nord Stream 2 over the last three years. Apparently, the economic prize was not considered that important, while at the same time there were a number of other underlying economic and political interests at play[15] between Turkey and Ukraine which prevented a flare up of public protests.

In order to understand Kiev's tame reaction to the completion and operation of TurkStream, one has to look at the regional picture. A new type of gas market is shaping up in SEE where long-term oil-indexed gas contracts are gradually giving way to gas-to-gas competition through the emergence of gas trading hubs. Already a number of such hubs are in operation in an embryonic form in SEE, while two of them (Greece's HTP and Turkey's UDN) will soon become fully-fledged hubs[16]. It would be fair to say that Ukraine aspires to partake in these developing hubs, where the Trans Balkan Pipeline could still play key role as it is still the prime energy backbone connecting all regional markets and originates in Ukraine.

9 For a detailed description of TurkStream, see Chapter 9.2 and also www.wikipedia.org/wiki/TurkStream
10 Assenova, M. (2021), "Mitigating the Nord Stream Two Impact on Ukraine", Eurasia Daily Monitor, Volume 18, Issue 93, https://jamestown.org/program/mitigating-the-nord-stream-2-impact-on-ukraine/
11 Makogon, S. (2020), "The Trans-Balkan Pipeline Reimagined", Natural Gas World, https://www.naturalgasworld.com/trans-balkan-pipeline-ggp-82781
12 For a detailed description of the Nord Stream project, see www.wikipedia.org/wiki/Nord_Stream
13 Chazan, G. and Manson, K. (2021), "Biden to waive Trump-era sanctions on operator of Russian pipeline", Financial Times, https://www.ft.com/content/22555df1-0b88-4d46-8287-9e0c8f03cc6a
14 Prokip, A. (2020), "A New Era of Gas Wars between Ukraine and Russia?", Wilson Center, https://www.wilsoncenter.org/blog-post/new-era-gas-wars-between-ukraine-and-russia
15 Scazzieri, L. (2021), "From partners to rivals? The future of EU-Turkey relations", https://www.cer.eu/sites/default/files/pbrief_turkey_LS_23.6.21.pdf
16 IENE (2020), "Prospects for the Establishment of Gas Trading Hubs in SE Europe", Working Paper 28, https://www.iene.eu/articlefiles/working%20paper%20no28.pdf

Although all regional gas markets, including Greece, Bulgaria, Serbia, Romania and North Macedonia, will soon be linked via cross-border interconnectors (as described in detail in Chapter 9.2), the Trans Balkan Pipeline will remain the only single gas artery capable of shipping sizeable gas quantities from north to south and vice versa. Therefore, this gas pipeline, whose ownership and management is shared by all the national gas transmission operators, far from being decommissioned, has a role to play in strengthening energy security and ensuring greater market competition. Soon it will have a role to play in sustainabililty, too, as pipelines must be able to accommodate biomethane and hydrogen in order to comply with the new "clean gas" environment pursued by the EU[17].

The East Med pipeline is yet another major gas project in the region, still in its infancy, but it is already causing some geopolitical friction between Greece and Turkey. This planned pipeline, with a total length of 1,900 km and a yearly capacity of some 10.0 bcm, aims to ship gas from the East Mediterranean's rich gas fields (offshore Israel and Cyprus) to Europe via Greece. Although the project is still on the drawing board, it has been heavily supported by the EU. It has been included as a Project of Common Interest (PCIs) since 2014, as Brussels believes that when completed this new pipeline will further help diversify EU's gas supply. East Med, whose total construction cost is estimated at nearly $7.0 billion, is politically supported by the US as it will help lessen EU's energy dependence on Russia.

However, the East Med project is not welcomed by Turkey, which sees the pipeline as a further excuse by Greece to impose its presence in the eastern Mediterranean Sea, a large part of which is claimed by Turkey. In this sense, Turkey feels that the East Med pipeline poses a challenge to its sovereign rights in the region and has stated on repeated occasions that it

Map 4.5 **The Expanded South Corridor**

NB.: The TANAP, TAP and Turk Stream have been completed, while BRUA and IGB are still under construction. The IAP, the IGI Poseidon in connection with East Med pipeline and the Vertical Corridor and the IGF are still in the study phase. Blue Stream and Trans Balkan are existing pipelines.
Source: IENE

[17] Van Nuffel, L. et al. (2020), "Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure", European Commission, https://op.europa.eu/en/publication-detail/-/publication/10e93b15-8b56-11ea-812f-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search

will strongly object to the underwater pipeline crossing its EEZ[18]. As Turkey and Greece have not yet demarcated their sea borders as part of an overall EEZ agreement, plotting the route of the East Med poses some technical challenges and an alternative route may have to be agreed.

Seen in a broader perspective the construction and operation of huge gas infrastructure projects, such as Nord Stream, TurkStream and East Med, inevitably carries a heavy political concomitant burden as the rearrangement and reshuffling of gas flows causes ripple effects at various levels. They alter the energy security architecture and redistribute income from gas sales and transit fees. Judging from experience so far in the European scene, we see that in most cases energy security, at both the demand and supply end, prevails over all other considerations. In the case of SEE, the energy security dimension in major gas infrastructure works is even more apparent.

Conflicts and Cooperation in the East Mediterranean

The recently discovered oil and gas fields in the Eastern Mediterranean have inspired a powerful energy alliance between Greece, Cyprus, Israel and lately Egypt, which challenges Turkey's role as the primary energy hub of the region. Tensions between Greece and Turkey over Eastern Mediterranean oil and gas fields, intertwined with maritime claims, rapidly escalated in the summer of 2020. On August 10, 2020, Turkey sent the Oruc Reis research ship, accompanied by warships to explore for hydrocarbon resources in the waters between Crete and Cyprus, which Greece claims as its own. Since then Greece has responded by sending warships in the area, and on one occasion both countries' vessels collided. The escalation of Greek-Turkish relations has compromised the energy ambitions of private actors and regional nation-states and has exacerbated an already challenging regional security environment. (10)

Regional tensions and skirmishes between Greece and Turkey are nothing new. Greece and Turkey have historically disagreed on the status of Cyprus, following Turkey's 1974 invasion on the island and its continuing occupation. This resulted in the establishment of the Turkish Republic of Northern Cyprus, solely recognized by Turkey. The proximity of the Greek islands to the Turkish mainland has also been a source of friction and disagreements. Most notably, in 1996, the two countries almost went to war due to a series of disputes over the demarcation of exclusive economic zones (EEZ), territorial waters, continental shelf, international flights rights, and demilitarisation of Greek islands in the Aegean Sea. (11)

On February 27, 2020, Turkey's announcement that it would not be able to keep migrants from entering the EU[19] renewed tensions between Ankara and the block, and the resultant migrants crossing from Greece and Turkey, among other issues, have strained relations between the two countries in 2020. Moreover, Ankara's decision to turn Hagia Sophia, a Byzantine-era cultural and historical landmark, back into a mosque, provoked public feelings in the Greek Orthodox world and received serious disapproval from Greece and several other countries, including the US.

A major paragon of the current crisis has been the result of both countries' competition over securing hydrocarbon reserves and their ongoing tensions regarding EEZ claims over large chunks of sea territory. Turkey has argued that Cyprus's resources should be shared and in defiance has carried out a number of drillings (in 2018 and 2019[20]) within Cyprus's internationally recognized EEZ, clearly trespassing the island's sovereignty. Turkey stepped back from drilling in September 2020. However, in November 2020, Ankara signed an agreement with the then UN-recognised Libyan Government of National Accord (GNA), establishing an EEZ from the southern Turkish coast to the northern Libyan coast, ignoring Crete's

[18] Daily Sabah (2020), "Ankara slams EastMed pipeline, opposes any gas project excluding Turkey", https://www.dailysabah.com/diplomacy/2020/01/03/attempts-to-exclude-turkey-in-east-med-futile-foreign-ministry-says
[19] https://blogs.lse.ac.uk/europpblog/2020/03/25/greek-turkish-border-crisis-refugees-are-paying-the-price-for-the-eus-failure-to-reform-its-asylum-system/
[20] https://www.ceps.eu/wp-content/uploads/2021/05/PI2021-09-Turkey-and-the-Eastern-Mediterranean.pdf

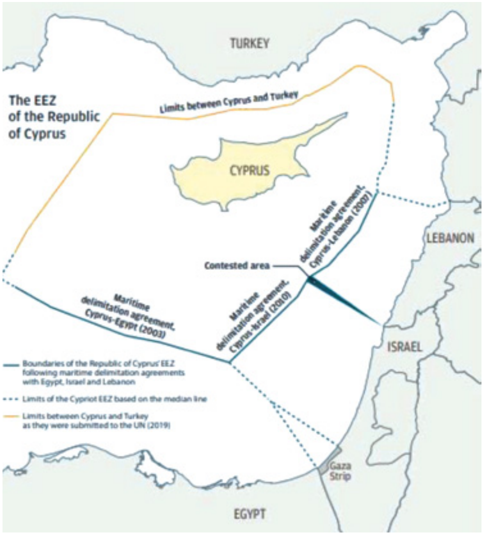
territorial waters, Greece's EEZ and continental shelf (12). In early August 2020, Greece and Egypt reached a deal, creating a partial EEZ between the two counties' coasts, which contradicted the Turkish-Libyan agreement. This resulted in Turkey's decision to send the Oruc Reis research ship near the small Greek island of Kastellorizo. Since the incident in the summer of 2020, tensions have been high with Turkey threatening Greece with war if it does not withdraw its naval vessels from the area. In a show of support, the US and France have sent their warships to the region and conducted numerous military exercises with Greece.

Background to the Overlapping Claims between Greece and Turkey in the Aegean and the East Mediterranean

There is no area more suitable than the Eastern Mediterranean where energy related geopolitical conflicts can best be illustrated. Here we have two neighboring countries which have progressively grown more hostile to each other as certain key events have occurred since the early part of the 1970's. A strong antagonism took hold as oil and gas resources were discovered by Greece in the northern Aegean and then in the summer of 1974 Turkey invaded the northern part of Cyprus. Hence, Greece and Turkey have been at loggerheads over a number of issues mainly related to the delimitation of sea boundaries and the definition of EEZ.

One would need hundreds of pages to review the entire Greek-Turkish conflict on the maritime border demarcation issue and in addition cover Turkey's strong objections of Cyprus's right to an EEZ, even though this has been declared following lengthy negotiations with neighboring countries, i.e. Egypt, Israel and Lebanon (see Map 4.6). Given Turkey's strong presence in the East Mediterranean on account of its extensive coastline and cultural ties with most countries in the region and the Greece-Cyprus axis which is exerting an equally strong influence in SE Europe, and given the history of recent incursions by Turkey in the vicinity (Invasion of northern Cyprus in 1974 and more recently in northern Syria) in the case of EEZ disputes between all above three countries, we have in this situation the seeds of a potentially huge conflict which could easily spill out politically and militarily and destabilize the entire Mediterranean.

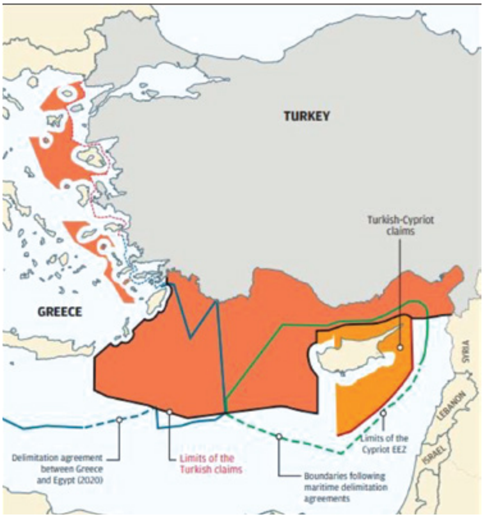
Map 4.6 **The EEZ of the Republic of Cyprus**



Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations"

In order to appreciate the enormity of the issue, we have selected a number of maps taken from the Atlas of Greek-Turkish Relations (13), which show the relative positions of Cyprus, Greece and Turkey. We start with Cyprus where Turkey on account of its unwavering position that it does not recognize the right of the island to have an EEZ, other than a very narrow strip, has on several occasions proclaimed its rights through the publication of maps (see Map 4.7) but also more actively by carrying out hydrocarbon exploratory drilling operations within Cyprus's EEZ much to the consternation of the oil companies which are already operating within Cyprus's EEZ (being the legitimate holders of exploration licenses awarded to them by the Republic of Cyprus) and to the dismay of the Cyprus's government itself.

Map 4.7 **Maritime Claims of Turkey and of Turkish-Cypriots in the Aegean and the Eastern Mediterranean**



Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations"

In the case of the Aegean and Greek seas in general, Turkey's claims on the country's continental shelf go back even further in time, in the early 1970's when Greece first discovered oil and gas in the northern Aegean, off the island of Thasos in 1970/1971. It was in 1973 when the government in Ankara first published a series of maps laying claim to large chunks of sea in the northern and eastern part of the Aegean Sea which is surrounded by islands belonging to Greece. Since then, Turkey has laid claim to a number of sea areas which Greece considers home ground in an effort to expand its own sea territory, especially following the birth of the "Blue Homeland" concept which has been systematically cultivated by Turkey over the past few years (see Map 4.8).

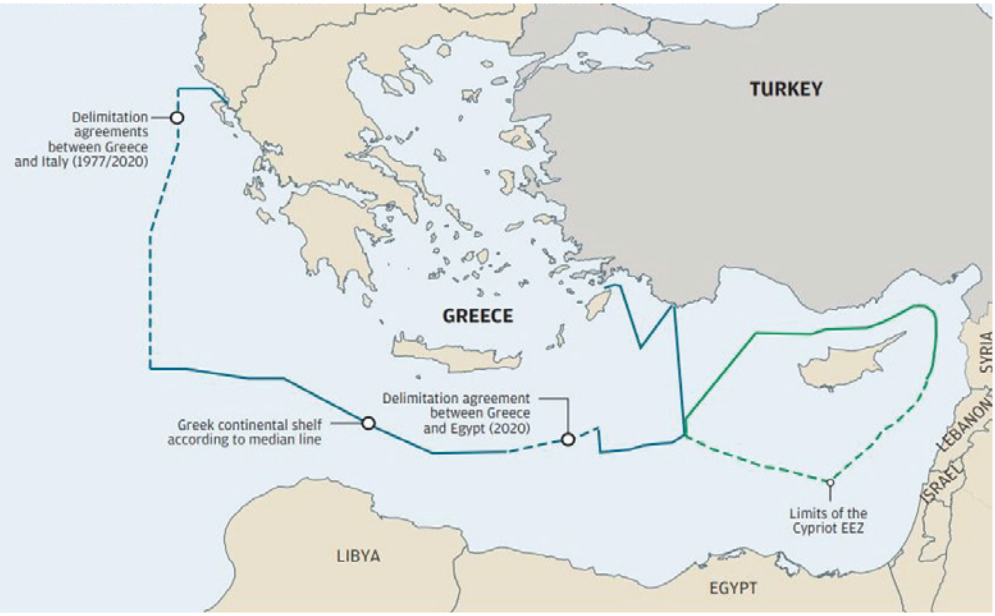
Legal uncertainties further complicate a possible solution of the EEZ dispute and a de-escalation of tensions in the region. Greece's maritime claims are based on the UN

Map 4.8 **Comparison between the "Blue Homeland" [Mavi Vatan] Doctrine and the Map Submitted to the UN in March 2020 Showing the Areas of the Eastern Mediterranean Claimed by Turkey**

Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations"

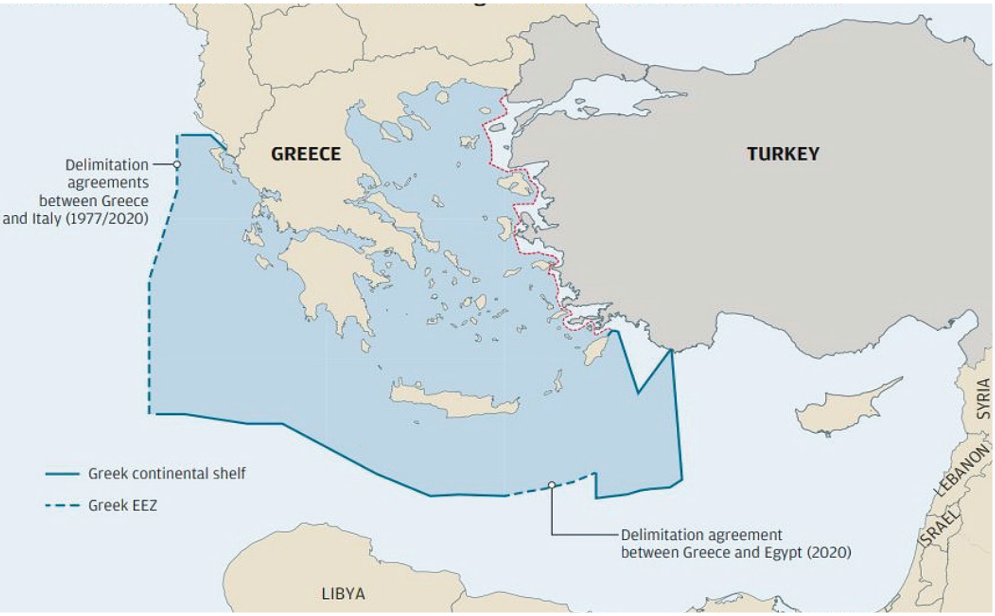
Convention on the Law of the Sea (UNCLOS), which provides every Greek island with maximum territorial waters (up to 12 nautical miles) and EEZ (up to 200 nautical miles) (see Map 4.9). A map, which depicts the above, known as the Seville map, and authorized by the European Commission in the early 2000s, has been dismissed by Turkey as "unjust and unfair". Although Ankara's territorial waters and continental shelf are curtailed by the full application of UNCLOS provisions and with Turkey not being a signatory to the Convention, solution of this conflict as proposed by subsequent Greek governments and several experts, can only be reached by a mutually agreed appeal to an International court, i.e. the International Tribunal for the Law of the Sea in Hamburg or the International Court of Justice in the Hague. The situation is further complicated by Ankara's maritime agreement with the GNA, which actively dismisses the territorial waters and EEZ of Greece off Crete. This is in violation of UNCLOS to which Greece is a signatory.

Map 4.9 **Limits of the Greek Continental Shelf/EEZ and of the Cypriot EEZ**



Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations"

Map 4.9.1 **Greek Continental Shelf and EEZ in the Aegean and Eastern Mediterranean**

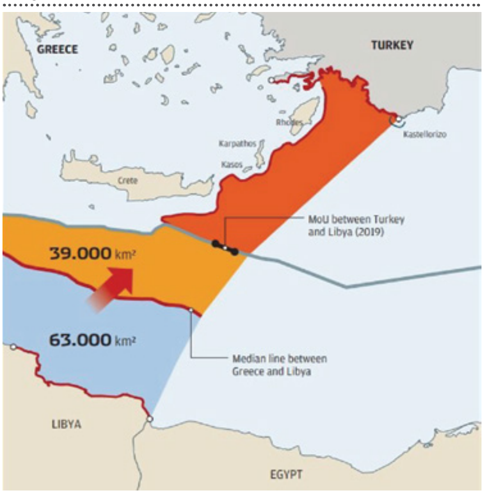


Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations"

Turkey's canning moves to secure ample maritime zones in the East Mediterranean culminated in November 2020 when a "Memorandum of Understanding" was signed between the Turkish President Reception Tayyip Erdogan and the head of the Libyan "Government of National Accord", Fayez al Sarajevo, which concerned the delimitation of maritime areas (see Map 4.10). Although the MoU has no binding authority under international law, it does constitute a precedent because of its content. And its content clearly violated the International Law of the Sea (UNCLOS) as Turkey and Libya delimited the sea region south of Crete, an area which does not neighbor with Turkey. But it should be noted that Turkey does not recognize UNCLOS which it has not signed.

However and regardless of Turkey's abstention, the International Law of the Sea has international validity as it has been ratified by more than 160 countries. Greece ratified the Convention in 1995 and is bound by it. Turkey, in contrast, voted against it. And in this move by Turkey lies the crux of the matter since by feeling not bound by UNCLOS it has a freedom of movement to declare sea areas which present a potential economic interest (see Map 4.10).

Map 4.10 **Turkey's Proposed Delimitation with Libya**



Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations"

The governments of Greece and Turkey, having long recognized the importance of finding a lasting solution concerning the demarcation of the sea areas of interest to both countries since 2002, have instituted a round of exploratory talks between high-ranking officials and so far they have held 63 such meetings with the aim of reaching an agreement on the commencement of proper negotiations over the demarcation of maritime zones. The "exploratory talks" followed the Greek-Turkish rapprochement which began in the summer of 1999 after major earthquakes in Istanbul in August that year and Greece's solidarity and help to Turkey. The agreement aimed through the above "exploratory talks" would provide for any matters not resolvable through negotiations to be referred to international talks. Following the revival of the talks in October 2020, there is speculation that an agreement may soon be feasible.

However, and in spite of the ongoing efforts to find a peaceful solution to EEZ claims and given the two countries' volatile history as on a number of occasions in the past, they were brought at the brink of war (1974, 1987, 1996, 2020), the very real prospect of an armed conflict between the two countries is still there. In this sense, exploring hydrocarbons and offshore wind potential in the Eastern Mediterranean is not only fraught with geopolitical difficulties but the area is very prone to destabilisation. This is important to bear in mind as the energy potential of the broader region in the south east flank of Europe is huge and could, if developed fully, provide an alternative energy supply to the rest of Europe. Whereas Norway has emerged as a reliable energy supplier for the EU in the north, Israel-Cyprus-Greece could develop an equal capability in the south.

The Broader Picture

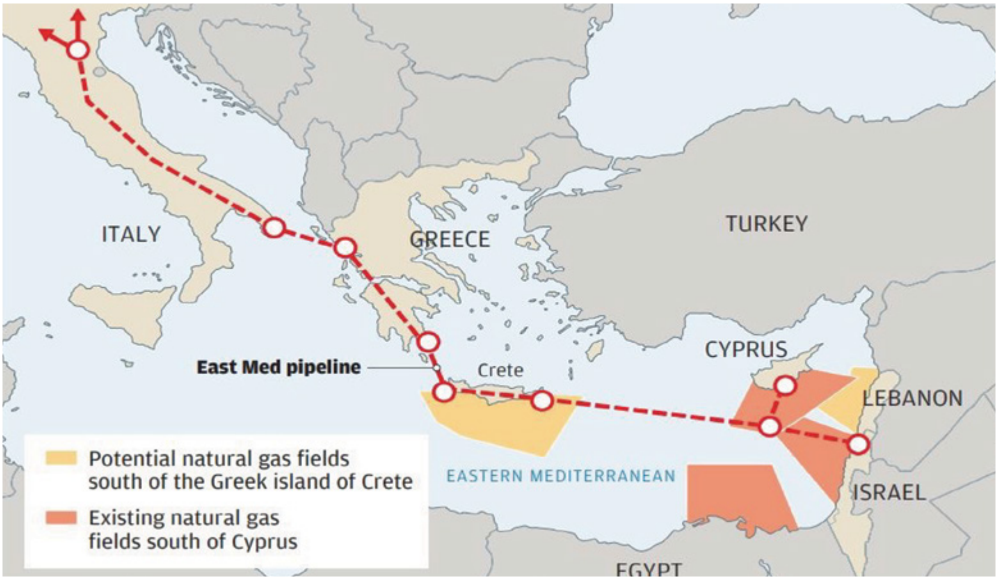
Seen in a broader context, the current maritime escalation between Greece and Turkey exceeds usual neighborly quarrels, as it adds tension to an ongoing struggle for resources in the Eastern Mediterranean. Since Israel's discovery of the Leviathan gas deposit in December 2010 and Egypt's discovery of the Zohr gas deposit in 2015, the previously deemed oil-and-gas-free region has attracted the attention of international investors and European and Middle-Eastern states. The discoveries of Leviathan and Zohr and Cyprus's Aphrodite gas field in 2011 and subsequent discoveries offshore Cyprus since then (see Chapter 8) have encouraged the strategic co-operation between Israel, Greece, Cyprus, and Egypt, which formed the East Med Gas Forum (14). This powerful geopolitical alliance apparently challenges Turkey's ambitions of becoming a major maritime energy player in the region.

Furthermore, on January 2, 2020, Greece, Cyprus, and Israel signed an intergovernmental agreement to build a 1,900-km pipeline, known as the East Med, transmitting natural gas to Europe and bypassing Turkey. As discussed in Chapter 9.2, progress on this project has been slow with the detailed engineering study, backed by EU funds, slated for completion by the end of 2021. If this project is implemented, the East Med pipeline could cover almost 4% of EU's gas supplies from Israeli and Cypriot fields (see Map 4.11). Meanwhile, drillings off Cyprus's waters were temporarily put on hold due to Covid-19 complications, while the American ExxonMobil, Qatar Petroleum, and Italian Eni, among other key players, have stated (summer 2021) that they intend to resume their exploration efforts from early 2022 onwards.

In addition, with its continuing claims in the East Med, off Cyprus and Greece, Turkey is now focusing on the development of its substantial gas resources it discovered in 2020 in the Black Sea. In June 2021, Turkey announced a major discovery of new gas deposits in the Black Sea, where the country plans to start production in 2023. State energy company TPAO found 135 bcm of gas at the Amasra-1 offshore well, bringing the total amount of deposits discovered over the past year to 540 bcm; thus, confirming Turkey's vital role as a potentially major energy supplier. (15)

Even so, local resources are unlikely to satisfy Turkey's gas consumption, estimated at 50 bcm in 2020. Although we cannot at this stage accurately estimate the amount of gas that will be produced, it is understood that it will be no less than 10 bcma. Regarding Israel, the United Arab Emirates' Mubadala Petroleum, which belongs to Mubadala Investment Co, a sovereign wealth fund with $232 billion in assets,

Map 4.11 **The East Med Pipeline**



Source: Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations" signed a memorandum of understanding in April 2021, to buy a 22% stake in Israel's Tamar offshore field. Once completed, this will be the biggest business deal between the two Middle Eastern nations since they normalised their ties in August 2020[21].

While the recent escalation in the Occupied Palestinian Territories and Israel's intermittent bombing of the Gaza Strip are expected to significantly increase the political risks associated with investing in Israel's oil and gas sector, they are unlikely to deter Mubadala from completing this landmark deal. The UAE has a lot to gain from the purchase, believed to be worth as much as $1.1 billion, both economically and politically. Moreover, Israel is determined to complete the Mubadala deal at any cost, as it will stimulate more foreign investor interests in its oil and gas sector. To fully understand the significance of this deal, and why it is likely to go forward regardless of the latest round of conflict in the region, we need to look at the dynamics that led to its creation.

Israel is planning to launch a new bidding round for exploration and development licences in the marine territories surrounding its main gas fields – Tamar, Leviathan, Tanin and Karish – in the near future. It hopes that by issuing such licences it can significantly increase the volume of natural gas reserves that will be available to the country in the long run. To achieve this goal, however, it needs to attract interest from major international oil companies (IOCs) – something it struggled to do in its previous bidding rounds. Indeed, Israel's gas fields drew little interest from the main Western IOCs in the past, with the exception of Houston-based Noble Energy and, more recently, Chevron. The majority of industry giants, including ExxonMobil and Total, abstained from participating in Israel's previous bidding rounds, justifying their decision by pointing to the "complex" geopolitical situation around the country's energy resources.

Israel's gas fields may not be large enough to secure unconditional interest from the leading IOCs, but they are too large for the gas extracted from them to be consumed exclusively within Israel. As a result, to attract IOC interest and make use of these resources, Israel needs to demonstrate that the gas it will extract can be exported. But this is by no means an easy task and Israel will have to invest a little more on its external relations.

To enter the Asian markets, Israel will need to develop LNG liquefaction production capabilities – something it currently does not have. Moreover, these markets are highly competitive, so the Israelis may not be able to break into them even if they develop the necessary production capabilities. Hence, the only practical route at present is through Egypt's LNG export terminals and later through the planned East Med gas pipeline, which is to export gas exclusively to European markets. On top of the political and operational obstacles preventing Israel from securing major export deals, the significant security risks facing its fields are also posing a problem for its energy ambitions. In recent years, the Israeli authorities have been forced to admit that the country's oil and gas infrastructure is vulnerable to attacks from Gaza.

Despite tensions over exploration and production rights in the Mediterranean Sea bed, there is a huge economic and commercial potential to be exploited for the benefit of all, should the various warring parties decide to reach an agreement. As exploration continues, once the Covid-19 obstacles are overcome and more gas finds are confirmed, the region could well become a net gas exporter once local demand is satisfied. An excellent analysis by Marika Karagianni on "Energy: Factor of Stability or Conflict in the Eastern Mediterranean?" discusses in detail the viable export options and the opportunities. So the region, given some diplomacy and commercial cooperation, could well be transformed into an energy community. (16)

[21] https://www.aljazeera.com/opinions/2021/5/20/the-billion-dollar-uae-israel-gas-deal-will-go-forward

References

(1) REKK (2019), "The Southeast European Power System in 2030: Flexibility Challenges and Benefits from Regional Integration", https://static.agora-energiewende.de/fileadmin2/Projekte/2019/Southeast_European_power_system_in_2030/154_SoutheastEuropPowerSys_WEB.pdf

(2) ENTSO-e (2020), "Transparency Platform", https://transparency.entsoe.eu/

(3) European Commission (2020), "Quarterly Report on European Gas Markets", Volume 12, Issue 4, Q4 2019, https://ec.europa.eu/energy/data-analysis/market-analysis_en?redir=1

(4) EIB (2019), "EIB energy lending policy", https://www.eib.org/attachments/strategies/eib_energy_lending_policy_en.pdf

(5) Simon, F. (2021), "LEAK: EU experts to say nuclear power qualifies for green investment label", Euractiv, https://www.euractiv.com/section/energy-environment/news/leak-eu-experts-to-say-nuclear-power-qualifies-for-green-investment-label

(6) Abnett, K. (2021), "EU experts to say nuclear power qualifies for green investment label: document", Reuters, https://www.reuters.com/article/us-europe-regulations-finance/eu-experts-to-say-nuclear-power-qualifies-for-green-investment-label-document-idINKBN2BJ0F0

(7) IRENA (2019), "Renewable Energy Market Analysis: SE Europe", https://www.irena.org/publications/2019/Dec/RE-Market-Analysis-Southeast-Europe

(8) European Commission (2020), "An Economic and Investment Plan for the Western Balkans", https://ec.europa.eu/commission/presscorner/detail/en/IP_20_1811

(9) Energy Community Secretariat (2021), "Discussion Paper on Riding the Renovation Wave in the Western Balkans - Proposal for Boosting Energy Efficiency in the Residential Building Sector", https://www.energy-community.org/news/Energy-Community-News/2021/02/25.html

(10) Cevrioglu, E. (2020), "Turkey's Oruc Reis vessel on new duty in E.Med.: Min.", https://www.aa.com.tr/en/economy/turkeys-oruc-reis-vessel-on-new-duty-in-emed-min/1936940

(11) Saragerova, B. (2020), "Greece and Turkey: Energy Security Tensions in the Eastern Mediterranean", https://globalriskinsights.com/2020/09/greece-and-turkey-energy-security-tensions-in-the-eastern-mediterranean/

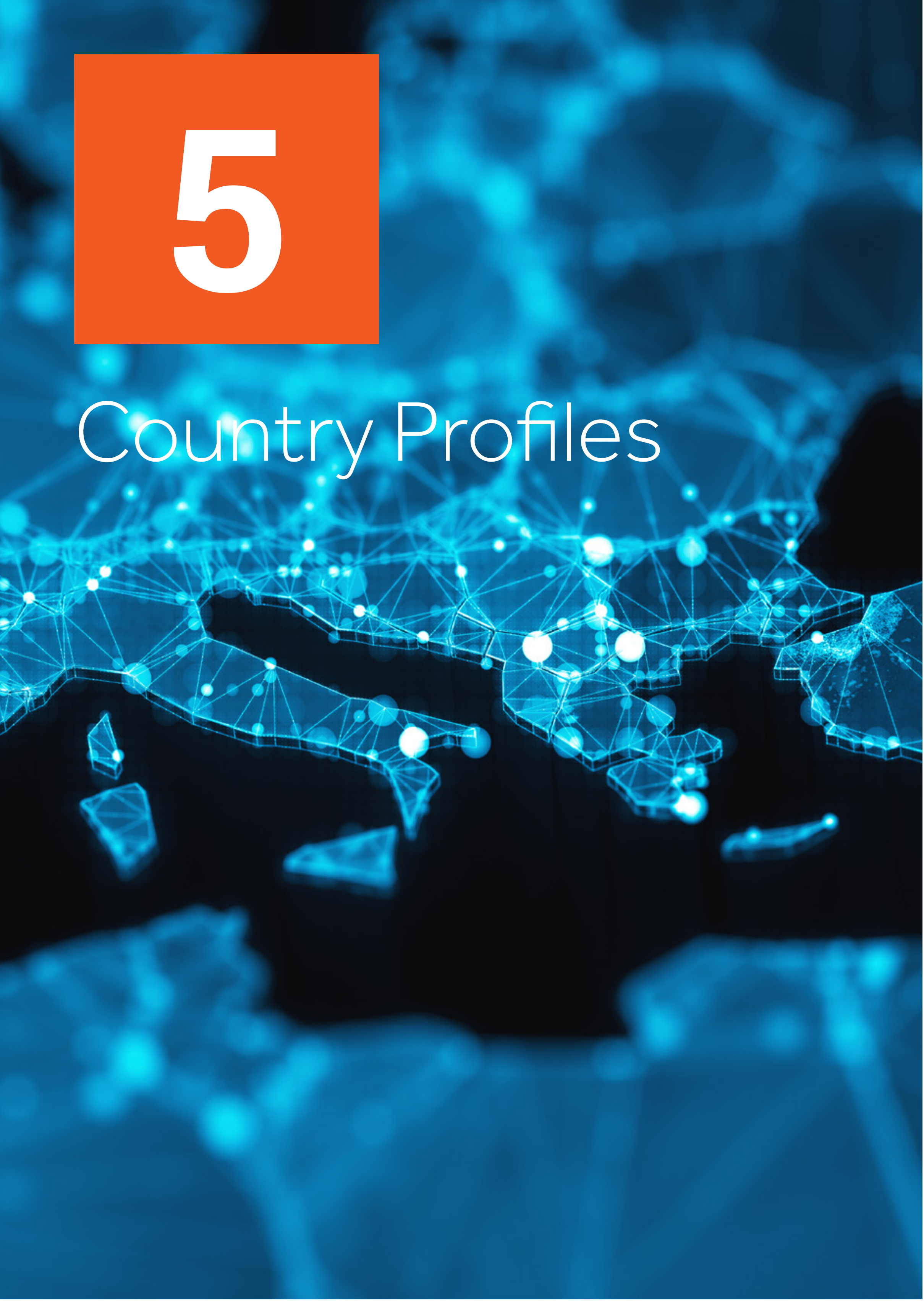
(12) European Parliament (2020), "Turkey: Remodelling the eastern Mediterranean", https://www.europarl.europa.eu/RegData/etudes/BRIE/2020/652048/EPRS_BRI(2020)652048_EN.pdf

(13) Syrigos, A. and Dokos, T. (2020), "Atlas of Greek Turkish Relations", Kathimerini Publications, https://www.syrigos.gr/books/Atlas_syrigos_dokos.pdf

(14) Matalucci, S. (2020), "EastMed Gas Forum fuels energy diplomacy in troubled region", https://www.dw.com/en/eastmed-gas-forum-fuels-energy-diplomacy-in-troubled-region/a-55206641

(15) Ozsoy, T. (2021), "Turkey announces significant new Black Sea natural gas discovery", https://www.worldoil.com/news/2021/6/4/turkey-announces-significant-new-black-sea-natural-gas-discovery

(16) Karagianni, M. (2021), "Energy: Factor of Stability or Conflict in the Eastern Mediterranean?", ELIAMEP, https://www.eliamep.gr/wp-content/uploads/2021/07/Policy-paper-77-Marika-KARAGIANNI-1.pdf



5

Country Profiles

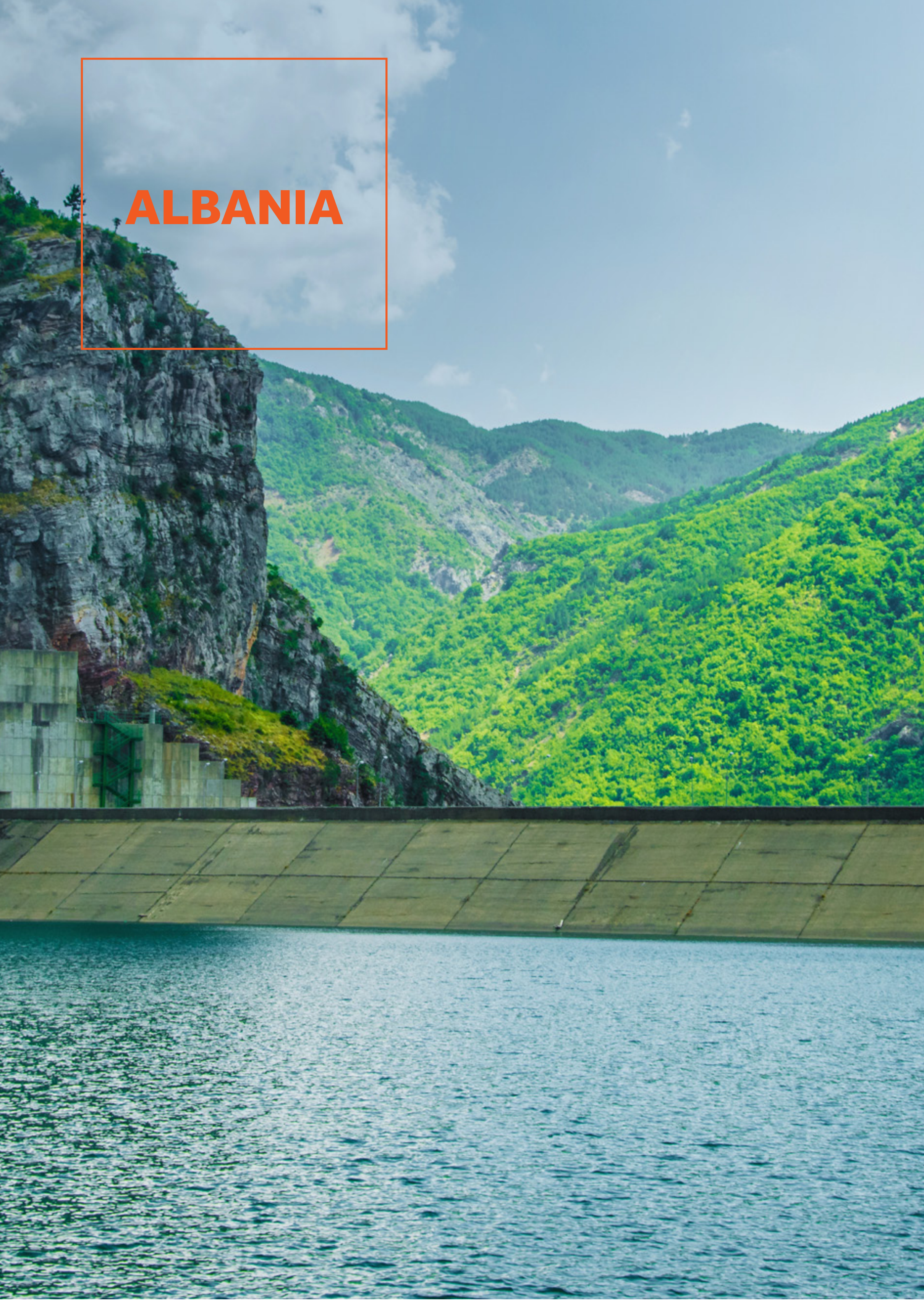
Introduction

In order to understand the energy structure of S.E. Europe it is important to have some basic knowledge on: (a) how the energy sector is organized in each one of the countries from a legal and administrative point of view, and (b) the basic energy magnitudes of each country, including energy production from indigenous sources, energy imports and exports, installed electricity capacity, refining capability, etc.

Such information is presented in a concise manner, wherever possible, for the following countries :

- **ALBANIA**
- **BOSNIA AND HERZEGOVINA**
- **BULGARIA**
- **CROATIA**
- **CYPRUS**
- **GREECE**
- **HUNGARY**
- **ISRAEL**
- **KOSOVO**
- **MONTENEGRO**
- **NORTH MACEDONIA**
- **ROMANIA**
- **SERBIA**
- **SLOVENIA**
- **TURKEY**

ALBANIA



Albania

Economic and Political Background

Albania's GDP declined by about 3.31% in 2020, based on preliminary estimates the country's statistical office released. In the fourth quarter alone, GDP grew by 2.99% year-on-year. On a quarterly comparison basis, GDP expanded by 1.15% in the three months through December.

The sectors that gave a negative contribution to GDP growth in the fourth quarter of 2020, as compared to the same period of 2019, were trade, transport, accommodation, food services, agriculture, forestry and fishing as well as net taxes on products. The main growth engines in the October-December period were construction, public administration, education and health, real estate activities and the industry, electricity and water group.

IMF projects that the Albanian economy will expand by 6.1% in 2021, significantly higher than -7.5% in 2020.

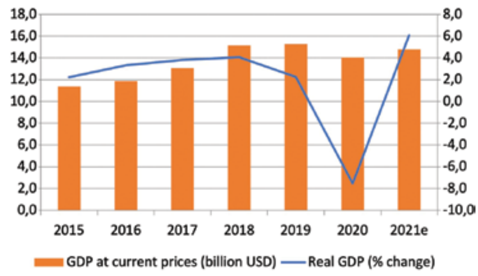
Table 5.1 **Main Economic Indicators for Albania Over 2015-2019**

Indicators	2015	2016	2017	2018	2019*
GDP ($ Billion)	13.03	13.47	13.98	14.56	15.40
GDP Growth (%)	2.2	3.3	3.8	4.1	3.5
GDP per Capita ($)	4,524	4,681	4,865	5,079	na
Industrial Output Growth (%)	2.58	1.90	1.90	9.12	na
Unemployment Rate (%)	17.08	15.12	13.75	12.40	na
Consumer rice (%)	1.9	1.3	2	2	2
Foreign Direct Investments (% of GDP)	8.7	8.8	7.7	8	na

* Figures for 2019 are projections.

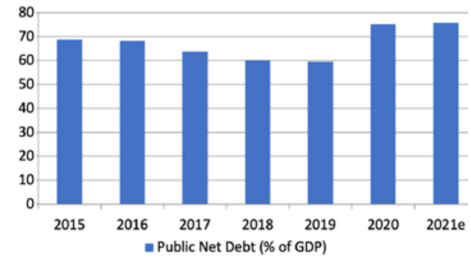
Sources: Bank of Albania, IMF, World Bank

Figure 5.1 **Albania's GDP and its annual GDP growth**



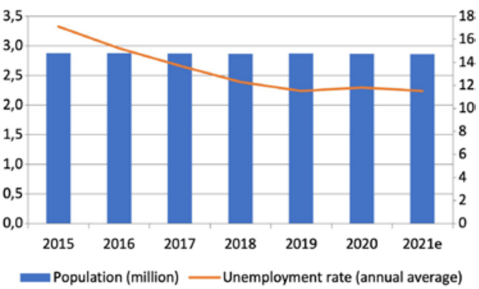
Source: IMF World Energy Outlook (October 2020)

Figure 5. 2 **Albania's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.3 **Albania's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

5

Energy Policy

National Energy Policy

Albania's government programme[1] for 2017-2021 stipulates that the government will aim to further develop the electricity sector, transforming it into a financially, operationally and technically viable sector capable of meeting the growing domestic energy demand, prioritizing the integration of the domestic energy market into regional and European markets, and reducing import dependency. The government's policy will continue to be oriented towards increasing the security of energy supply to consumers, aiming at supporting the sustainable economic development of the country, through increasing employment and promoting renewable energy and energy efficiency, stimulating competition in the market, ensuring stability and minimizing costs for Albanian consumers, as well as ensuring environmental protection.

The Ministry of Infrastructure and Energy[2] is responsible for drafting and implementing the general state policy in the energy sector and for the utilization of energy and mining resources.

With the implementation of the National Energy Strategy , the main energy policy document adopted in mid-2018, Albania aims to achieve the following results:

- Reduced energy imports and increased domestic energy generation by meeting future energy demand in a sustainable way while enhancing social welfare;
- Improved energy efficiency in the household, services, transport, agriculture and industrial sectors;
- Increased use of RES technologies, based on least-cost planning, resource diversification, climate change and environmental protection;
- Penetration of natural gas in the Albanian energy sector through infrastructure investments;
- Development of mechanisms to encourage foreign direct investment in the Albania energy sector through increased competition in the energy market, while maintaining the interests of
- Improving the harmonization and integration of Albanian energy sector policy and regulation with energy community acquis and regional and EU markets;
- Developing a policy framework for energy (including energy efficiency for sustainable transport) in transport based on the Albanian Transport Sector Strategy, and introducing new technologies in all its sectors;
- Developing a competitive market that provides correct signals for the production and consumption of electricity and gas;
- Focused activities related to the use, rehabilitation and improvement of existing inefficient energy infrastructure that adversely affect the environment and potentially high value areas for other development sectors, such as tourism, agriculture, etc.

Some of the **concrete** objectives set by the National Energy Strategy 2018-2030 are as follows:

- Continuing to reduce losses in the electricity distribution network from 26.4% in 2017 to 10% in 2030;
- Continuing to increase electricity receipts from 90% in 2018 to 98% in 2030;
- Increase the contribution of primary energy sources to total primary energy supply at 52.5% in 2030;
- Electricity market opening rate to reach 100% in 2025;
- The Albanian economy and society reach a level of energy saving versus total consumption of 15% in 2030;
- Target of renewable energies to total consumption reaches 42% in 2030;
- GHG emissions reduction to total reach 11.5% in 2030;
- Penetration of natural gas against total supply of primary energy sources reaches 20% in 2030.

National Action Plan for Energy Efficiency (NAPEE) and National Action Plan for Renewable Energy Sources (NAPRES) (updated every 2 years) have been developed and implemented to meet the targets for renewable energy and energy efficiency.

[1] http://www.financa.gov.al/wp-content/uploads/2017/09/PROGRAMI_2017_-_2021.pdf
[2] Decision of the Council of Ministers No. 480, dated 31.7.2018 'On approval of the National Energy Strategy for the period 2018-2030'.

Governmental institutions

The **Council of Ministers** is responsible for the overall development policies of Albania's energy sector, in line with economic development policies and other sectors of the country.

The **Ministry of Infrastructure and Energy** is responsible for drafting and implementing the general state policy in the energy sector. It prepares the National Energy Strategy, mid-term programs for the development of various energy sectors, assesses the need to build new generation capacities and to strengthen energy networks, collects and processes data and information on national energy balance, develops policies and programs for the implementation of energy objectives and policies, environmental protection measures, harmonization with European Union standards and regulations in the field of energy, supervises the implementation of energy sector development policies and programs in line with the economic and social development of the country.

The **Energy Regulatory Entity** or "ERE" is the regulatory authority for the electricity and natural gas sectors in the country. ERE is an institution independent of the interests of the energy industry and state authorities, aiming at promoting and creating a competitive market and eliminating restrictions on the trading of energy products both domestically and at the level of the SEE Energy Community and beyond, as well as the sustainable development of these sectors, protecting the environment and ensuring that customers benefit from market functioning.

The **National Agency of Natural Resources** (AKBN) is an institution under the auspices of the Minister of Infrastructure and Energy. Its activity is the development, supervision of rational utilization of natural resources, based on governing policies, and monitoring of their post-exploitation in the mining, hydrocarbon and energy sectors.

The **Agency for Energy Efficiency (AEE)** is an institution under the auspices of the Minister responsible for energy. The AEE is responsible for implementing policies and promoting energy efficiency measures.

Agency responsible for renewable energy sources to be created according to Renewable Energy Law.

The **Technical and Industrial State Inspectorate (ISHTI)** conducts inspections in the field of safe processing, transportation and marketing of oil and gas and their by-products, ensuring the safety of people and material values from the risks of gas leaks and explosions caused by pressure equipment, as well as from equipment and wiring. It exercises its regulatory function in accordance with the needs of the country, national defense and public security, while respecting the principles of a market economy.

The leading public and dominant companies in the electricity sector

Albanian Electricity Corporation (KESH sh.a.), a 100% state-owned company, is the public producer and at the same time the largest producer of electricity in Albania. KESH operates the main electricity generation plants in the country. These assets consist of the Drini river cascade hydropower plants (HPP Fierza, HPP Koman and HPP Vau i Dejes) with an overall installed power of 1,350 MW, and the Vlora TPP with an installed capacity of 98 MW.

Transmission System Operator (OST sh.a) is a 100% state-owned public company that operates the electricity transmission system in Albania. OST performs the functions of Transmission Network Operator, Dispatch System Operator and Market Operator.

OST is responsible for the operation, maintenance and development of the transmission system, including interconnections with other cross-border systems, to ensure the long-term capability of the system to meet reasonable electricity transmission requirements.

Electricity Distribution Operator (OSHEE sh.a.) is a 100% state-owned public company that operates the electricity distribution network alone in Albania and performs its electricity supply function as a as Universal Service Supplier (USS) under the public service obligation. In fact, OSHEE sh.a. is in the process of dividing the company into two parts, one dealing only with the physical distribution network and its operation, and the other with the supply of electricity to customers.

In 2018 ERE has approved the separation of roles by the transfer of the license for the Electricity Distribution System Operation to the company "Distribution System Operator" sh.a. (O.S.SH sh.a.) and of the license for Electricity Supply to the company "Universal Service Supplier" sh.a. (FSHU sh.a.), that will continue to operate for a transition period under the umbrella of OSHEE SHA until the full real separation. ERE licensed also a newly established state-owned company, the "Free Market Supplier" (FTL sh.a.) in the electricity trading and supply activity. This company shall be complementary with the O.S.SH sh.a. and FSHU sh.a., but it will be completely separate from them.

Leading public companies in the hydrocarbon sector

Oil and gas exploration and production

Albpetrol sh.a. is a joint stock company established in 26.11.1998 with 100% of the shares owned by the Albanian state. Albpetrol is Albania's state-owned oil company inheriting all its oil assets and resources from the previous General Directorate of Oil and Gas. It also owns oil production fields in Fier, Ballsh, Kucova, Patos etc and is also shareholder in a few Joint Ventures it has established with international companies for the production and development of a number of existing oil fields like Patos-Marinez, Delvina, Kocove etc.

"Bankers Petroleum Albania", is a private company and operates the Patos Marinza oilfield in Albania pursuant to a licence agreement. Patos Marinza oilfield near the city of Fier is the largest sandstone onshore oil field in Europe. Bankers Petroleum has ranked the fifth largest company in Albania for years 2018 and 2019 based on its turnover. From September 2016 Bankers Petroleum Ltd. is 100% owned by the Chinese corporation "Geo-Jade Petroleum Corporation" ("Geo-Jade") [3].

Natural gas

(a) Operation and maintenance of transmision distribution systems

Albgaz Sh.a. is a joint stock company established on 07.12.2016 with 100% of the shares owned by the Albanian state. Albgaz Sh.a will operate as a combined operator performing the activity of the transmission system operator and the natural gas distribution system operator in the Republic of Albania.

Albanian Gas Service Company Sh.A was established on 17.10.2018 as a joint venture company between Albgaz (75%) and Snam (25%) as a fully operative company responsible for the maintenance and technical services for Trans Adriatic Pipeline in Albania accordance with a Joint Agreement entered between the company and TAP for such services.

TAP-AG Ltd, in accordance with the Host Government Agreement with the government of Albania has established its presence in Albania and has been licensed by ERE as a TSO and certified as an ITO.

(b) Trade of natural gas and LPG

Two LPG terminals ensuring ship unloading and LPG storage are located in Porto Romano in Durres and in the bay of Vlora in the south. Both terminals are operated by private companies respectively; "ROMANO PORT" SHA and "LA PETROLIFERA ITALO ALBANESE" SHA (PIA)
Other main companies involved in the LPG wholesale and retail markets are: IB GAS AG, INTER-GAZ SHA, A&V-GAS SHA, AV DISTRIBUTION SHA, FAM GAS L.L.C., KEVIN GAZ SHA dhe, EMANUEL GAS SH.P.K.

Trading of petrol, diesel and other by products

There are no public companies in the trade of petrol, diesel and other oil by products in Albania.**"Kastrati"** a 100% private company, for years is positioned as the main wholesale and retail trader of petrol, diesel and oil by products in Albania. Again, in year 2018 it ranked first among top 200 Albanian companies. Its turnover for year 2018 was three times higher than its closest competitor "**Genklaudis"**[4] **.**

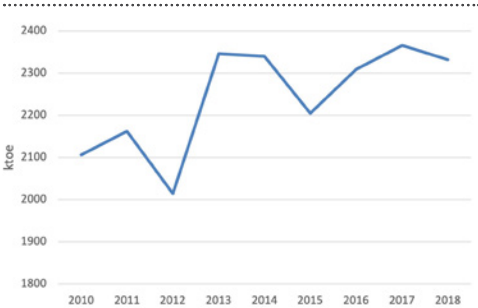
Other private companies involved in the trade of petrol, diesel and other oil by products are; **"Genklaudis", "Europetrol Durrës Albania" "Tosk Energy", "Bolv Oil", "Gega Center GKG" & "Gega Oil".**

Energy Demand and Supply

National energy demand

The gross domestic energy consumption in general has been increasing, but fluctuating throughout the period 2010-2018. In 2016 and 2017 there was an increase of consumption by 4.7% and 2.5%, respectively, compared to the previous year, while in 2018 a decrease of 1.4% compared to the previous year. Figure 5.4 shows the gross domestic energy consumption between 2010 and 2018.

Figure 5.4 **Gross domestic energy consumption 2010-2018**

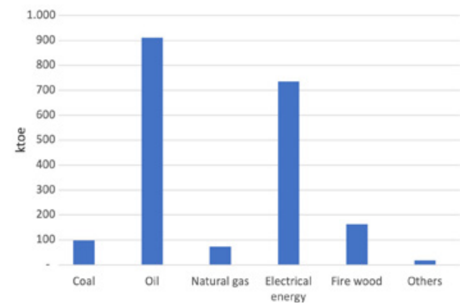


Source: INSTAT, AKBN

National energy supply

Albania produces most of the energy it consumes. Figure 5.5 shows domestic production of primary energy for 2018.

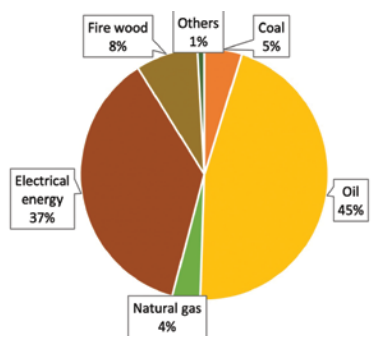
Figure 5.5 **Domestic production of primary energy products for 2018**



Source: INSTAT, AKBN

The structure of domestic production of primary energy for 2018, is shown below:

Figure 5.6 **The structure of domestic production of primary energy for 2018**



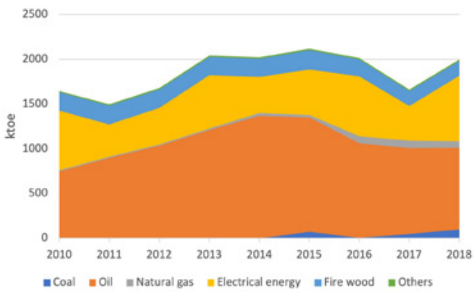
Source: INSTAT, AKBN

Domestic supply consists mainly of oil, electricity and firewood. Oil and electricity are the main indigenous primary energy sources in Albania which covered 45.6% and 36.8% respectively, of total primary energy supply contributing together 82.4% of the primary energy. The contribution of coal and natural gas is marginal, albeit with a slight increase in the last three years.

[3, 4] https://www.monitor.al/200-vip-at-e-2018-viti-i-koncesioneve-2/

Albania's total primary energy supply 2010-2018 is shown in Figure 5.7:

Figure 5.7 **Total Primary Energy Supply 2010-2018**

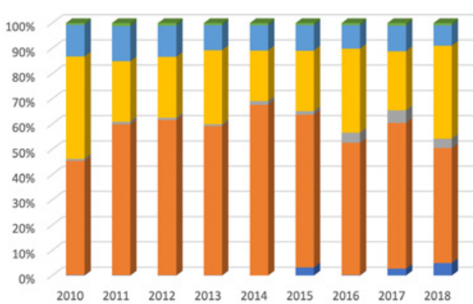


Source: INSTAT, AKBN

The supply has a slight upward trend, but often with strong fluctuations like that of 2017, mainly due to the very low production of electricity from hydro sources, which is highly dependent on weather conditions. Electricity production in 2017 was about 58% (389 ktoe) of a year earlier (669 ktoe). Oil production peaked in 2014 at 1368 ktoe, maintained stability in 2015, and has stabilized at a new equilibrium of around 1,000 ktoe during the last three years. Total domestic production of primary energy products in 2018 compared to 2010 increased by 354 ktoe or 21.5%. However, over time this performance has been fluctuating. In 2016 there is a decrease of 4.9% from the previous year, in 2017 another decline by 17.5% compared to 2016, while in 2018 an increase of 20.2% compared to 2017 and 15.9% compared to 2015.

The percentage structure of domestic supply for the years 2010-2018 is shown in Figure 5.8:

Figure 5.8 **The percentage structure of domestic energy supply for the years 2010-2018**

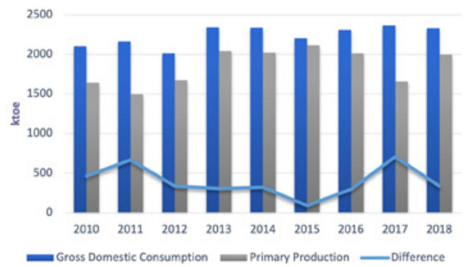


Source: INSTAT, AKBN

Energy balance

Gross National Energy Consumption, Domestic Primary Energy Production and the Difference between Consumption-Domestic Production during 2010-2018, are shown in Figure 5.9.

Figure 5.9 **Gross National Energy Consumption, Domestic Primary Energy Production and the Difference Consumption-Production during 2010-2018**



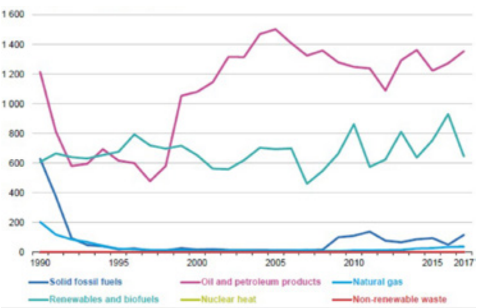
Source: INSTAT, AKBN

The difference between national gross consumption and domestic production has always been in favor of consumption. The energy deficit reached its lowest point in 2015, where consumption was slightly higher than production by only 88 ktoe. In 2016 the difference increased again to 296 ktoe. In 2017 the difference reached 705 ktoe, and in 2018 the gap narrowed again to 335 ktoe.

Energy mix

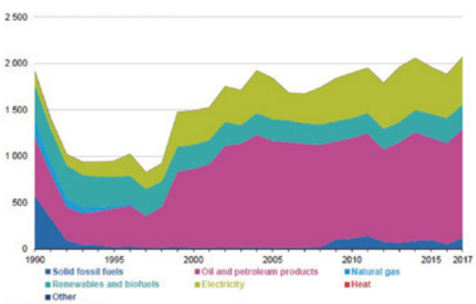
Starting from 1999 Albania's energy mix remains dominated by hydrocarbon products while electricity from renewable sources (hydro) has increased at a moderate level demonstrating at the same time high fluctuations as shown in the charts below (see Figures 5.10 and 5.11).

Figure 5.10 **Albania Gross Available Energy by Fuel (ktoe) for the period 1990-2017**



Source: Eurostat; Energy balance sheets 2017 DATA

Figure 5.11 **Albania Energy Consumption by fuel** [5]

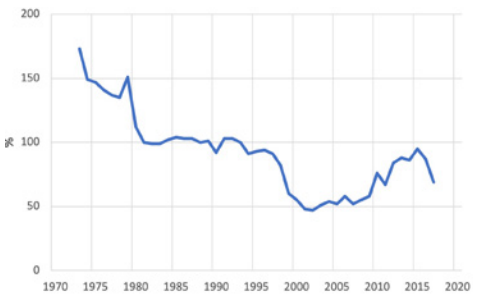


Source: Eurostat_nrg_bal_c, "Energy Balance Sheets 2017 DATA"

Energy Dependence

Until 1993 Albania covered entirely its energy demand through its own domestic resources. After 1993, mainly due to the significant drop of domestic crude oil production Albania became a net importer and its level of energy dependence went below 50% in 2002. After 2003 Albania's energy Self Sufficiency Rate (%) (Total domestic energy production/TPES) has shown a constant recovery until the year 2015 when Albania covered up to 95% of its total energy needs. In 2016 the self-sufficiency rate dropped again to 87% and further down to 69% in 2017 as shown in the chart below: As explained, one of the main goals of the current energy strategy is to attract investments in the energy sector and hence improve the degree of energy dependence.

Figure 5.12 **Self Sufficiency Rate (%) 1973-2017**



Source: IEA (2019), World energy balances 2019

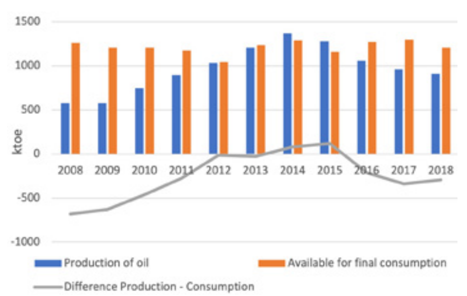
The Energy Market

Oil and Petroleum Products

(a) Oil supply and demand

During 2008-2018 Albania's domestic production of crude oil surpassed its annual consumption only in 2014 and 2015. Maximum crude oil production was reached in 2014 with 1,368 ktoe (approx. 27,360 barrels per day) surpassing the annual consumption by 81 ktoe. The annual production in 2015 was 1,279 ktoe (25,580 barrels per day) surpassing domestic consumption by 119 ktoe as shown in the graph below. The level of oil production has been highly influenced by international oil prices as well as from internal developments.

Figure 5.13 **Albania's crude oil domestic production and yearly consumption and the difference between them during the period 2008-2018**



Source: INSTAT

[5] Source: Eurostat_nrg_bal_c, "Energy Balance Sheets 2017 DATA"

Crude oil and electricity from hydro are the most important energy products of Albania. During the last decade hydrocarbons have contributed the largest share of Albania's energy balance reaching a maximum of 66.2% in year 2016.

Table 5.2 **Share of hydrocarbon products in the Albania's final energy consumption during the period 2014-2018**

Oil	2014	2015	2016	2017	2018
Available for final consumption ktoe	1,287	1,160	1,270	1,299	1,206
% to final energy consumption	62.2%	58.8%	66.2%	62.8%	58.1%

Source: INSTAT

(b) Oil imports/dependence

As explained in the previous section Albania's domestic crude oil production has been able to meet the domestic consumption of hydrocarbons only for a relatively short period of time (2012-2015). Since then Albania has become again a net importer of hydrocarbon products as domestic consumption of oil has steadily increased. The chart below provides the level of crude oil production by type of reservoir and the level of hydrocarbons imports in the country.

Figure 5.14 **Albanian domestic production (from limestone and sandstone reservoirs) and imports in ktoe**

Source: AKBN[6]

(c) Upstream sector - domestic production and exploration

After its shift to free market economy Albania adopted an ambitious strategy to attract investment in the area of oil and gas exploration and for ongoing oil and gas production. A new petroleum law was approved by the Albanian Parliament (Law No.7746, date 28.07.1993, as amended). The wholly integrated and state-owned oil and gas sector was transformed into a commercial company named Albpetrol. Albanian off shore and onshore were divided into blocks and promoted to attract foreign investments. Albpetrol was also unbundled and given the right to enter into petroleum agreements (in the form of PSA = Production Sharing Agreements) with other oil and gas companies to explore its blocks and enhance oil production from the existing oilfields. Since 2004 the government of Albania has signed 16 production sharing agreements (PSA) for the oil and gas exploration and production. Seven companies are involved in the production of crude oil in the southern part of Albania and four companies are involved in exploration activities[7]. A detailed account of exploration and production activities follows.

(i) Oil and Gas Exploration

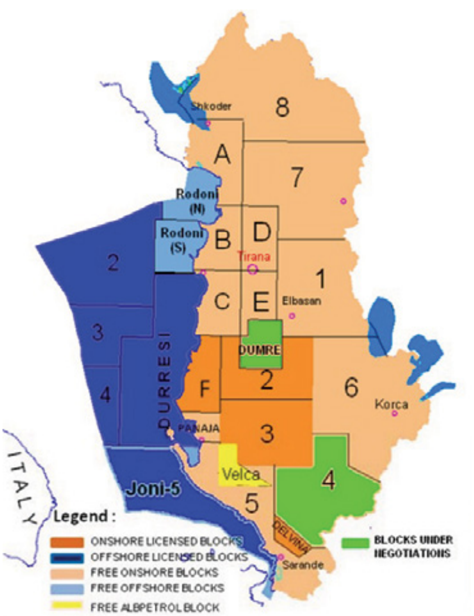
The first area which opened for offshore exploration was in Blocks 2 and 3 (see Map 5.1). Major companies signed PSA's with the Albanian state, but so far no commercial discovery has been declared in Albanian seas.

Map 5.1 shows the current division and the status of the Albanian onshore and offshore blocks;

[6] "Bilanci Kombetar i Energjise 2017", page 8 / National Energy Balance, page 8 https://www.akbn.gov.al/wp-content/uploads/2019/02/Raporti-i-Bilancit-2017-ok3.pdf

[7] "Albanian Extractive Industry and the role of Production Sharing Agreements" / "Marreveshjet me Ndarje Prodhimi ne Industrine e Naftes" Eduart Gjokutaj https://www.altax.al/al/publikime-te-altax/product/mnd-ne-industrine-e-naftes-sistemi-fiskal-dhe-korrupsioni.

Map 5.1 **Albania Exploration Blocks**



Source: AKBN [8]

The list of Petroleum Agreements held by AKBN on 31 December 2015 as stated in the latest report of EITI are given in Table 5.3:

Table 5.3 **List of Petroleum Agreements (as of 31 December 2015)**

Operators of the PSA	Petroleum operation	Oil and gas blocks	Date of PSA
Sari Leon Energy B.V.	Exploration, development and production	Offshore exploration block Durres	August 2007
Capricorn Albania Limited	Exploration, development and production	Offshore exploration block Joni 5	September 2007
Bankers Petroleum Albania Ltd	Exploration, development and production	Onshore exploration block F	November 2010
Royal Dutch Shell plc & Petromanas Energy Inc.	Exploration, development and production	Onshore exploration blocks 2 & 3	July 2009

Source: EITI [9]

During 2016-2019 the following announcements were made by the Ministry of Infrastructure and Energy (MIE), concerning hydrocarbon exploration:

- On 15 March 2016, MIE signed a petroleum agreement with Albanides Energy Ltd, for the onshore exploration Block No 8. However, no other announcement has been made concerning progress in this block [10].
- On 20.02.2018, MIE[11] signed a petroleum agreement for oil and gas exploration for the onshore Block No 4. The contract is for 25 years with the right of renewal in case of discovery. The contract will be implemented in three phases with specific commitments for each phase.
- On 02.05.2019 MIE[12] and SHELL signed an amendment of the petroleum agreement for Blocks 2 and 3. According to MEI after several years of exploration activity SHELL confirmed the potential of an important new discovery in Blocks No 2 and No 3 in the Shpirag area in Berat district.
- On 20.12.2019 MEI[13] and Italian ENI signed a petroleum agreement for the Dumrea Block in Elbasan district. The block covers an area of 587 km^2.

In addition to petroleum agreements signed by the Ministry the following developments have taken place on Albpetrol's exploration blocks;

- On February 14, 2017 the Pennine Petroleum Corp. cosigned a production sharing agreement with Albpetrol SH.A for the exploration and development of the Velca block in Albania Source[14]. However, no further announcements have been made on the progress of its implementation.

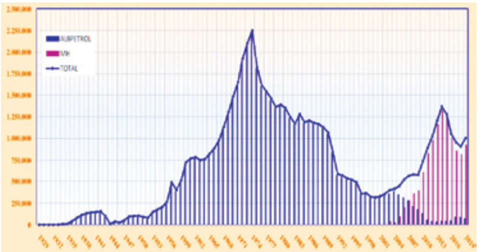
ii) Oil and gas production

The history of Albanian crude oil production is shown in the chart in Fig.15. The whole crude oil production was under state control until year 1993. Since then several petroleum agreements (MH in the chart below,

8 http://www.akbn.gov.al/ (as of 20 April 2020)
9 "Extractive Industries Transparency Initiative in Albania, Report for the year 2015" Deloitte, published in December 2016
10 "Extractive Industries Transparency Initiative in Albania, Report for the year 2015" Deloitte, published in December 2016
11 https://www.infrastruktura.gov.al/nenshkruhet-me-shell-marreveshja-e-kerkimit-per-bllokun-nr-4/
12 https://www.infrastruktura.gov.al/nenshkruhet-marreveshja-me-kompanine-shell-balluku-kontrate-e-reformuar-rrit-dhe-modernizon-sektorin-e-hidrokarbureve/
13 https://www.infrastruktura.gov.al/marreveshje-hidrokarbure-per-bllokun-dumrea-me-kompanine-italiane-eni/
14 https://www.reuters.com/article/idUSFWN1FZ15J

Marrveshjet Hidrokarbure) have been signed for the development of the existing oil fields with Patos-Marinza being the largest existing oilfield.

Figure 5.15 **Albania's History of Crude Oil Production**



Source: AKBN

The actual figures of crude oil production for the last three years is given in Table 5.4:

Table 5.4 **Albania crude oil production during 2017-2019**

Year	2017	2018	2019
Crude oil production (tons)	955,068	910,683	1,004,998

Source: AKBN

As already mentioned, the highest level of crude production during recent years was attained in 2014 with 1,368,233 tons.

From Table5. 4 it can be easily seen that the share of production from the petroleum agreements has dramatically increased, starting from year 2004 and currently constitutes almost the total crude oil production of the country.

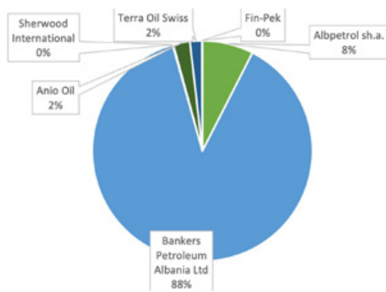
The list of the current petroleum agreements for the existing oilfields in Albania and their level of crude oil and gas production for the year 2019 is given in Table 5.5.

Table 5.5 **Crude oil and gas production for year 2019 in Albania**

no	Company	Oil Field	Oil Production (2019) tons	% to total production
1	Albpetrol sh.a.		75,415	7.52%
2	Bankers Petroleum Albania Ltd	Patos-Marinez	885,692	88.13%
3	Sherwood International	Kuçove	1,172	0.11%
4	Delvina Gas Group	Delvine	-	0%
5	Anio Oil	Ballsh-Hekal	24,439	2.43%
6	Terra Oil Swiss Transoil Group/Visokë		17,778	1.77%
7	Fin-Pek	Finiq-Krane, Pekisht-Murriz	502	0.04%
	Total		1,004,998	100%

Source: AKBN

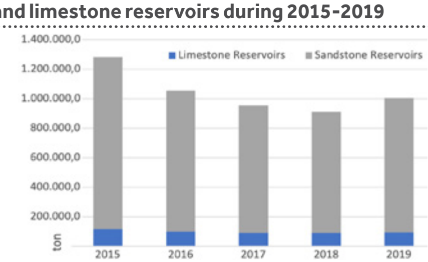
Figure 5.16 **Share of crude production from the existing oilfields for year 2019**



Source: AKBN, graph prepared by SEA Consulting

"Bankers Petroleum Albania Ltd" which is producing in the Patos-Marinza oilfield remains the dominant producer with 88% of the Albanian total production in year 2019. The oil production during the last five years (2015-2019) from limestone and sandstone reservoirs is given in Figure 5.17.

Figure 5.17 **Albania crude production by sandstone and limestone reservoirs during 2015-2019**



Source: AKBN

(d) Downstream and midstream sectors and infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

Albania's crude oil production is mostly exported to be refined abroad. Domestic consumption of refined oil is fulfilled through imported oil. Albpetrol pipelines are not currently operating. Two crude oil pipelines link ARMO's oil terminal in Vlora with Fieri and Ballshi refineries and the two refineries between them. Both pipelines are not operating due to obsolescence. The oil pipeline network has a total length of 188 km and a capacity of 2.5 million tons per year.

(e) Security of supply

The Ministry of Infrastructure and Energy (MEI) has initiated a public consultation for the draft law on "the establishment, storage and management of the minimal reserves of crude oil and its byproducts" which is expected to bring positive impacts on the security of supply with crude oil and its byproducts.

(f) Planned new projects

The new oil and gas projects in Albania are mainly related with to the development of the national natural gas network and its connection with the region like the IAP and ALKOGAP pipelines. Albania has prepared its gas master plan since 2016 while prefeasibility studies have been prepared for IAP and ALKOGAP. No other significant decisions have been made.

(f) Planned new projects

The new oil and gas projects in Albania are mainly related with to the development of the

Natural Gas

(a) NG Supply and Demand

An actual natural gas market does not yet exist in Albania. The current domestic production of associated gas from the existing oil fields is very modest at less than 100 MNcm/year for 2017 and is used for the technological and protection needs of the producing companies[15]. The Gas Master Plan of Albania foresees an initial gas demand at the level of 1.14 BCM/year to grow up to 2.44 BCM/year over a 20-year period.

(b) NG Imports

The only gas interconnector that makes Albania part of the Southern Gas Corridor, the Trans Adriatic Pipeline (TAP) is close to commissioning (3Q 2020) and is expected to start operations before the end of 2020. However, no local developments have taken place so far in Albania that would make possible the use of gas sources via TAP in the near future.

The TAP system will be operated by a single center outside Albania. TAP has the obligation to build two exit points in Albania with capacities to be finally agreed with the government of Albania. The locations of both exit points are already agreed at the Fier compressor station and the second one in Ura Vajgurore. In accordance with the joint decision of the energy regulators of Greece-Albania and Italy known as the Final Joint Opinion, TAP has the obligation to run market tests every two years and in case of positive results to make the justifiable exit capacities available. The government of Albania is making efforts to take advantage of the presence of transiting natural gas flows in the country.

Use of LPG (through butane and propane) started from early 2000 and has since continuously increased. The consumption data are presented in Table 5.6.

Table 5.6 **Import and consumption of LPG in Albania during 2005-2017 (ktoe)**

ALBANIA	2005	2010	2011	2012	2013	2014	2015	2016	2017
LPG (Net Imports) ktoe	64	110	114	99	159	177	208	214	285

Source: Eurostat_nrg_bal_c, "Energy Balance Sheets 2017 DATA"

There are two LPG importing terminals in the country and the number of companies involved in the LPG wholesale and retail trade is limited and has been subject of an investigation by the Competition Authority which was completed in 2017[16].

[15] AKBN "National Energy Balance" / "Bilanci Kombetar i Energjise 2017", page 9
[16] http://caa.gov.al/decisions/list/page/11

5

(c) Dependence (%)

Albanian produces only limited amounts of associated natural gas from its existing oilfields while there is an increasing amount of LPG imported to cover growing demand as shown in Table 5.7.

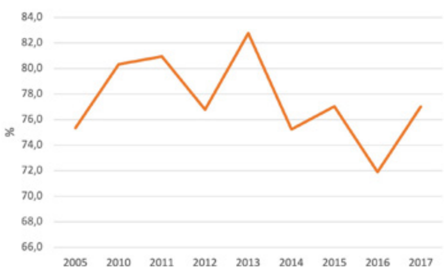
Table 5.7 **Associated gas production in Albania and LPG imports**

Natural Gas plus LPG (ktoe)	2005	2010	2011	2012	2013	2014	2015	2016	2017
Primary production (Accompanying Gas)	9	12	12	13	15	25	27	35	37
Net imports LPG (propane plus butane)	64	110	114	99	159	177	208	214	285
Gross available energy (Gas plus LPG)	73	122	126	112	174	202	235	249	322
Primary production Net imports	-55	-98	-102	-86	-144	-152	-181	-179	-248
Depen -dency (%)	75.3	80.3	81	76.8	82.8	75.2	77	71.9	77

Source: EUROSTAT, 2019

As data and the chart in Fig. 5.18 show gas consumption in Albania is highly dependent on LPG imports which was 71.9% for 2016 and 82.8% in 2013.

Figure 5.18 **Dependency from LPG imports**

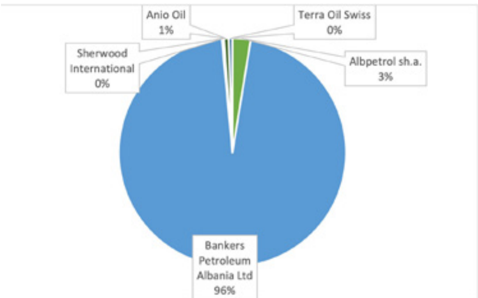


Source: INSTAT

(d) Domestic Production and Exploration

The amount of associated gas produced in Albania in 2019 was only 80 million NCM mostly produced by the Patos Marinza oilfield as shown in Fig. 5.19.

Figure 5.19 **Production of associated gas**



Source: AKBN

In May 2019 Shell Upstream Albania announced the discovery of a new oilfield in the Shpiragu region in Albania[17]. The company has started the evaluation phase of the project and initial tests have shown signs of a gas condensate discovery with high percentage of natural gas content.

(e) Infrastructure (Pipelines, Storage)

The Trans Adriatic pipeline is the main achievement so far in Albania in the natural gas sector. TAP[18] is part of the Southern Gas Corridor bringing the Caspian gas into Europe. Its initial capacity is 10 BCM capable of expanding to 20 BCM as demand increases and additional quantities of gas become available. The HGA and the energy regulators decision (Final Joint Opinion) creates all the necessary conditions for Albania to benefit from the availability of the transiting gas across the country as well as for expediting any excess gas production in the country in case of new commercial discoveries.

(f) Domestic Gas Market

Albania is a Contracting Party of the Energy Community Treaty and has continuously progressed into the adoption of the EU acqui in the energy sector. Law No. 102/2015 on the Natural Gas Sector transposes the Directive 2009/73/EC. Several other secondary legislative acts have been developed and approved and work on additional acts is progressing.

(g) National NG policy - strategic plan

The recommended scenario by the Albanian National Strategy of Energy for the period 2018-2030 is the scenario that combines energy

[17] https://ata.gov.al/2019/05/27/kerkimet-e-shell-ne-shpirag-zbulimi-i-pare-i-nje-vendburimi-te-ri-te-naftes-ne-30-vitet-e-fundit/

[18] https://www.tap-ag.al/gazsjellesi

efficiency (EE), Renewable Energy sources (RES) and promotes the use of natural gas. Being one of the three main pillars for the development of the energy sector the government has carried out the Gas Master Plan (GMP) that was approved in 2018. The GMP provides detailed analysis for the development of the gas sector following completion of TAP pipeline. However, until end of 2019 no much domestic infrastructure development has taken place in the field while TAP has announced its start of operations within 2020.

(h) Planned new projects

The main natural gas infrastructure projects articulated by the Albanian government include:

- Spur line to supply the CCGT Vlora power plant
- The Ionian Adriatic Pipeline, the interconnector that all connect Albania – Montenegro – Croatia and B&H.
- ALKOGAP, the interconnector that will connect Albania with Kosovo.

Development of underground gas storage facilities

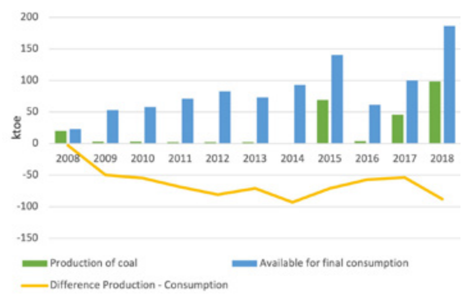
Albania has several suitable sites for gas storage, including, a salt dome in Dumrea (up to 2 bcm) and the depleted Divjaka gas field (up to 1 bcm).

Solid Fuels

(a) Supply and consumption

Domestic production of coal is at very modest levels. However, during the last 3-4 years coal consumption has increased at the level of 100 ktoe/year, out of which half is secured by domestic production.

Figure 5.20 **Domestic production of coal and the difference between consumption and production for the period 2008-2018**



Source: INSTAT

As shown in Table 5.8 the highest consumption was in 2018 constituting 9% of the total primary energy consumption.

Table 5.8 **Coal participation in final energy consumption for the period 2014-2018**

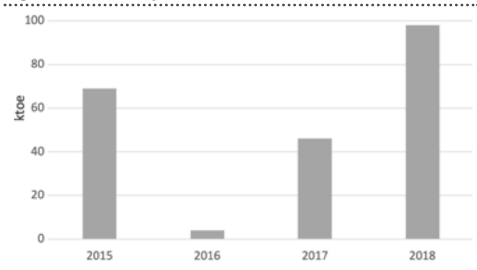
Coal	2014	2015	2016	2017	2018
Available for final consumption ktoe	93	140	61	100	186
% to Final Energy Consumption	4.5	7.1	3.2	4.8	9.0

Source: INSTAT

(b) Local production and exploration

After a long absence and following termination of coal production in 1990, Albania resumed coal production in 2015 and has since extracted coal in modest quantities (see Fig.5.21 and Table 5.9) at very modest levels.

Figure 5.21 **Coal production in Albania (2015-2018)**



Source:AKBN

Coal production in 2018 constituted 4.9% of the total of primary energy consumption in Albania. There are no developments reported in relation to any new coal extraction project.

Table 5.9 **Coal production in Albania (2015-2018)**

Coal	2015	2016	2017	2018
ktoe	69	4	46	98
% to total primary energy production	3.3	0.2	2.8	4.9

Source: AKBN

(c) Deposits

Coal

According to AKBN, Albania has considerable coal reserves. The total geological reserves discovered, so far are estimated to amount to

794 million tons. Around 85% of the reserves are located in the Tirana's coal-bearing deposit, 9,2% in Morava and Gore-Moker regions and 4.4% in Memaliaj deposits. Albanian coal reserves are of the lignite type, with a calorific value varying between 2,000 - 5,600 KCal/Kg.

Map. 5.2 **Location of lignite reserves in Albania**

Source: AKBN - www.akbn.gov.al/images/pdf/publikime/Minierat.pdf

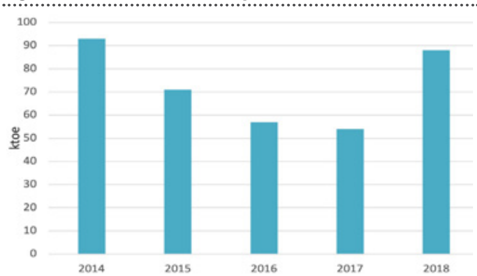
Peats (turfs)

Some peat zones are to be found along the moors of the Adriatic seaside, starting from Shkodra to Vlora and also in the Korca fields and Vurgu region. The moors where peats are found, have generally small size but should not to be underestimated. An important deposit was lately discovered in ex Maliqi moor, in Korca field. The peats discovered in this deposit are over 100 million m3, with 1,1% of sulphur content and 38,6 volatile content.

(d) Coal imports

Considering that coal consumption is modest such are also the imported amounts.

Figure 5.22 **Albania coal import**



Source: AKBN

(e) Planned new projects

No coal related projects are reported.

Electricity

Until 2018, Albania had been relying exclusively on hydropower to generate electricity. In 2019, though on a small scale, production from PV plants has begun, a trend that seems likely to continue at a higher pace. Generating electricity from natural gas is now also a distinct possibility thanks to the Trans Adriatic Pipeline, expected to start of operations by the end of 2020. The proposed 97 MW gas fired power plant at Vlora has been subject of tendering efforts by the Ministry of Energy without any concrete result so far (1Q 2020).

(a) Electricity supply and demand (in TWh)

Albania's electricity consumption reached around 7.2 TWh in 2018 and it has been growing at a moderate pace over the last ten years. The electricity demand for the year 2019 increased by 25.1% compared to 2009 with a yearly average growth of 2.26%.

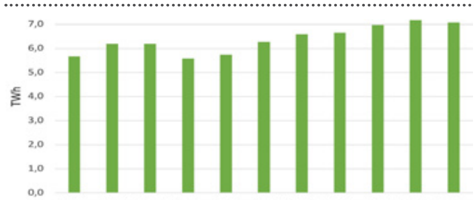
Table 5.10 **Albania's annual electricity consumption 2009-2019 (GWh)**

Years	Consumption* GWh	Annual Change %
2009	5,664	
2010	6,191	9.3%
2011	6,188	-0.1%
2012	5,578	-9.9%
2013	5,744	3.0%
2014	6,271	9.2%
2015	6,596	5.2%
2016	6,646	0.8%
2017	6,973	4.9%
2018	7,171	2.8%
2019	7,083	-1.2%

* Transmission & distribution technical losses are included. We use the term 'consumption' and not 'demand' because of the presence of non-technical losses
Source: ERE, Annual Report 2018

The dynamics of energy consumption for years 2009-2019 is also presented below:

Figure 5.23 **The dynamics of energy consumption 2009-2019**



Source: ERE, Annual Report 2018

However, electricity consumption growth rate has been irregular. In years 2011, 2012 and 2019 it has been lower than the previous year. Its complex variation is highly dependent from the level of control of non-technical losses. ERE power demand projections for for the next fifteen years period are given in Table 5.11.

Table 5.11 **Albania's annual electricity consumption 2009-2019 (GWh)**

Year	Demand (GWh)	Year (continuation)	Demand (GWh) (continuation)
2020	7,628	2028	9,079
2021	7,812	2029	9,261
2022	7,991	2030	9,446
2023	8,175	2031	9,625
2024	8,355	2032	9,808
2025	8,539	2033	9,995
2026	8,718	2034	10,184
2027	8,901	2035	10,378

Source: ERE, Annual Report 2018

The demand foreseen by ERE in the year 2035 is at around 10.4 TWh compared to 7.6 TWh in 2020. However, this forecast looks optimistic.

Table 5.12 **Albania's annual electricity production (GWh) over 2009-2019**

	Electricity Production		From which:			
Year	Total		Public Production (KESH SH.A.)		Private and Concession Production	
	GWh	Annual Change	GWh	Annual Change	GWh	Annual
2009	5,159	35.6%	4,686	37.0%	473	22.6%
2010	7,702	49.3%	7,014	49.7%	688	45.4%
2011	4,158	-46.0%	3,655	-47.9%	503	-26.8%
2012	4,722	13.6%	4,029	10.2%	693	37.8%
2013	6,957	47.3%	5,812	44.2%	1,145	65.2%
2014	4,724	-32.1%	3,409	-41.4%	1,315	14.9%
2015	5,866	24.2%	4,452	30.6%	1,414	7.5%
2016	7,136	21.7%	5,092	14.4%	2,044	44.6%
2017	4,525	-36.6%	2,917	-42.7%	1,608	-21.3%
2018	8,552	89.0%	5,851	100.6%	2,701	68.0%
2019	5,206	-39.1%	2,987	-48.9%	2,219	-17.8%

Source: ERE, OST sh.a., OSHEE sh.a.

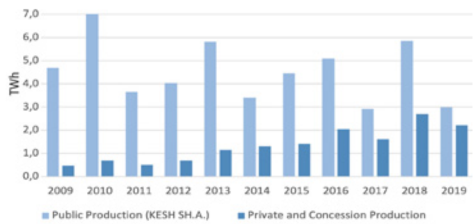
The total domestic electricity production comes from hydro generation. Despite the continuous increase of hydro generation capacity, the domestic power production remains highly dependent upon the hydrologic conditions and climate changes.

Figure 5.24 **Domestic electricity production, 2009-2019**

Source: ERE, OST sh.a., OSHEE sh.a.

Over the last years the share of power production by Small Hydro Power Producers (SHPP) largely privately owned or under concession agreements has seen a significant rise.

Figure 5.25 **The shares of public and private power generation production**



Source: ERE, OST sh.a., OSHEE sh.a.

The historical data of annual peak load in Albania over 2006-2019 is shown in Table 5.13.

Table 5.13 **Historical data of annual peak load in Albania over 2006-2019**

Years	Peak Load(MW)	Annual Changes(%)
2006	1,446	
2007	1,340	-7.3%
2008	1,397	4.3%
2009	1,306	-6.5%
2010	1,402	7.4%
2011	1,450	3.4%
2012	1,436	-1.0%
2013	1,540	7.2%
2014	1,475	-4.2%
2015	1,489	0.9%
2016	1,552	4.2%
2017	1,424	-8.2%
2018	1,480	3.9%
2019	1,498	1.2%

Source: ERE

Over the last five years a relative stabilization in peak load is observed. The electrical system is becoming more stable due also to the fact that the total installed capacity has been growing year by year.

(b) Installed Capacity (in MW)

The structure and key technical data of Albania's generating capacities according to key production technologies for 2018 is shown in Table 5.14.

Table 5.14 **The structure and key technical data of Albania's generating capacities for 2018**

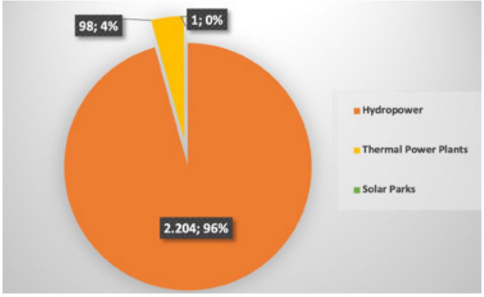
Technology	Number of units	Installed capacity		Ownership			
				Public		Concession or Private	
				Number of units	Installed capacity	No	Installed capacity
		(MW)	*%*		*(MW)*		*(MW)*
Hydro Power Plant (HPP)	165	2,204	95.70	3	1,350	162	854
Thermo Power Plant (TPP)	1	98	4.26	1	98	0	0
Solar Park (PV)	1	1	0.04	1	1	0	0
TOTAL 2018	167	2,303	100.00	5	1,449	162	854

Source: MIE, ERE, KESH sh.a.

As data shows, the capacity from hydro sources, in terms of installed capacity in MW and percentage size, remains the absolute dominant of Albania's total installed electricity capacity

.

Figure 5.26 **Total installed capacity (MW &%) per fuel type (end of 2018)**



Source: ERE, MIE, OST sh.a.

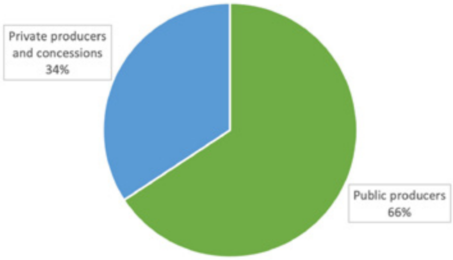
• Thermoelectric plants (coal, lignite, gas)

The only thermal power plant in Albania is the Vlora TPP with 97 MW of installed capacity which is currently not operational. This power plant can operate with two types of fuel. At the moment it can only work with diesel but it can be easily converted to natural gas. This TPP was planned to commence operation during 2011, but due to a breakdown in the cooling system, and the high cost of production with diesel the facility remains in-operational.

• Hydroelectric plants

In 2018 the total hydro installed capacity reached 2,204 MW out of which 1,448 MW or 65.7% belongs to state-controlled producers and 755.2 MW or 34.3% belongs to private producers and is run on a concession basis.

Figure 5.27 **State versus Private/Concession installed capacity in 2018**



Source: ERE, MIE, OST sh.a.

The following table provides details of hydro installed capacities according to connecting voltage level.

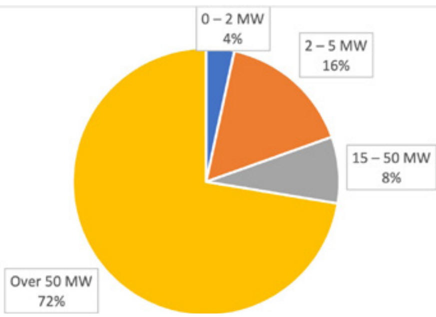
Table 5.15 **Total hydro installed capacity (end of 2018) according to connecting voltage level**

Hydropower - Grouping by Installed capacity	Connected to				TOTAL	
	Transmission Network		Distribution Network			
	No. of Units	Capacity MW	No. of Units	Capacity MW	No. of Units	Capacity MW
0 - 2 MW	7	8	81	67	88	75
2 - 5 MW	28	183	37	173	65	356
15 - 50 MW	6	177	0	-	6	177
Over 50 MW	6	1,595	0	-	6	1,595
TOTAL	**47**	**1,963**	**118**	**240**	**165**	**2,203**

Source: ERE, MIE, OST sh.a, OSHEE sh.a.

The structure of hydro installed capacity in 2018 is presented below.

Figure 5.28 **The structure of hydro installed capacity in Albania in 2018**



Source: ERE, MIE, OST sh.a, OSHEE sh.a

(c) Planned new capacity - investments

According to ERE (2018) the capacities which are in the construction process or have received preliminary approval or preliminary opinion, for their connection to the transmission network, are shown in Table 5.16.

Table 5.16 **New generation capacities under construction to be connected with the transmission network**

No.	Naming the Generation Units	Installed capacity (MW)
1	Devoll River Cascade, Moglica HPP	171.0
2	Other hydropower Plants	121.8
3	Photovoltaic Parks	7.5
Total		300.3

Source: ERE, Annual Report 2018

The biggest new power capacity expected to be commissioned in 2020 is Moglica HPP with 171 MW installed capacity.

In July, 2018, the government of Albania commenced the bidding process for the development of a photovoltaic plant project in Akerni (Vlore). The installed capacity of the plant shall be 50 MW, and it will benefit from the renewable sources support schemes. It will also have the possibility to expand with additional capacity from 20 MW up to 50 MW, but without any benefit from renewable sources support schemes. The duration of the Project Agreement is for 30 years, with the right of renewal. As part of the support measures, a Power Purchase Agreement (PPA) will be signed for a capacity of 50 MW for a period of 15 years. In November, 2018, the Ministry of Energy announced that the winner of the tender were was a consortium, following the merger of India Power Corporation ltd registered in India, Mininig Resources FZE, registered in UAE and Midami Limited, registered in Hong Kong. The award price was 59.9 Euro/MWh. Besides the announced timetable for the execution of the project, which was 18 months from the effective date, (which is the date of signing of the Project Agreement), no other progress has been reported so far. In the beginning of 2020, the Albanian Government launched another invitation to bid for projecting, financing, building, operating, maintenance and transferring of another photovoltaic power plant with 70 MWp installed capacity, in Fier area as part of renewable sources support schemes, and an additional 70 MWp installed capacity, which will not be part of the above renewable sources support schemes. The duration of the agreement between the Albanian Government-Contractor is predicted to last 30 years and the support scheme includes a 15-year Power Purchase Agreement (PPA).

(d) Electricity imports - exports

Table 5.17 **Electricity imports-exports over 2013-2019**

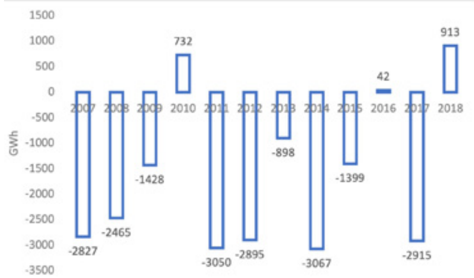
Years	Export	Import	Balance (Export - Import)
	GWh	GWh	GWh
2013	1,425	2,323	(898)
2014	288	3,356	(3,067)
2015	956	2,355	(1,399)
2016	1,869	1,827	42
2017	488	3,403	(2,915)
2018	2,685	1,772	913
2019	770	3,177	(2,406)

Note: Imports are in fact inflows and exports are outflows of electricity from the Albanian electricity system.

Source: ERE, OST sh.a.

Except for the years 2016 and 2018 Albania has been a net importer of electricity. The largest amount imported was 2,685 GWh in 2018 while it exported 3,403 GWh in the 2017. This trend is expected to continue in the near future. Table 5,17 shows selectively imports and exports for the period 2013-2019. The long-term data that is presented in Fig. 29 also shows that, with the exception of the two wet years 8the 2010 and 2018, that Albania has been a net importer of electricity.

Figure 5.29 **Electricity balance of imports - exports over 2007-2018**



Source: ERE, OST sh.a.

(e) Tariffs

Albania does not yet have a functional "day-ahead" and "intra-day" power markets and related activities, in compliance with the target model. Currently there is work in progress in order to establish a power exchange by the end of 2020 or during 2021.

In 2019 the majority of power (84.7%) has been traded in the regulated market. The remaining part (15.3%) was traded through bilateral contracts. The power consumption by the main groups is shown in Table 5.18.

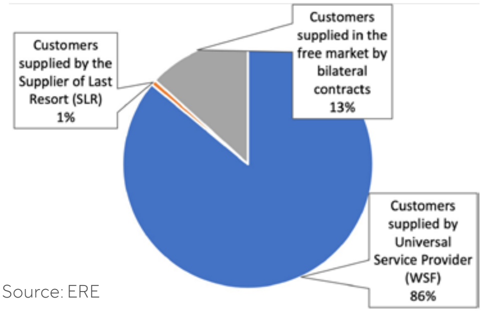
Table 5.18 **Quantity of electricity sold to each customer group**

No.	Quantity of electricity sold to each customer group	2017		2018		2019	
		TWh	%	TWh	%	TWh	%
1	At regulated prices	4.78	100	4.88	83.4	5.05	84.7
a.	Customers supplied by Universal Service Provider (WSF)	4.78	100	4.83	99.0	5.01	99.2
b.	Customers supplied by the Supplier of Last Resort (SLR)	0	0	0.06	1.2	0.04	0.8
2	At unregulated prices (Customers supplied in the free market by bilateral contracts)	0	0	0.97	16.6	0.91	15.3
	TOTAL	4.78	100%	5.85	100%	5.96	100%

Source: ERE

The share of electricity sold to each customer group in year 2019, is shown in Fig. 5.30:

Figure 5.30 **The share (%) of electricity sold to each customer group in the year 2019**



Source: ERE

ELECTRICITY/TARIFFS TRANSMISSION

There is a single transmission tariff for all users of the transmission network of OST. Sh.A. which is applied in all the transmitted power (ALL/ kWh). The transmission tariffs approved by ERE. for 2017, 2018 and 2019, are shown in the Table 5.19:

Table 5.19 **Transmission network use tariff**

No.	**Transmission network use tariff**	**Unit**	**2017**	**2018**	**2019**
1.	Transmission network use tariff	EURO/MWh	4.8	5.1	6.1

Note: The tariffs for 2017 and 2018 are equal, the changes in the above table come as a result of different ALL to EURO exchange rates in the respective years.

Source: ERE

It should be noted that the entire territory of Albania forms a single distribution zone. The distribution network operation is carried out by OSHEE sh.a, a public company (100% state owned). The distribution tariff is charged as a fee for the services offered by the use of the distribution network. The tariff is approved each year by ERE upon application by OSHEE sh.a.

The distribution tariff in Albania has remained the same for the whole period 2017, 2018 and 2019 (the changes shown in Table 5.20 below are due only to different ALL to EURO exchange rates in respective years):

Table 5.20 **Distribution network use tariffs**

No.	**Transmission network use tariff**	**Unit**	**2017**	**2018**	**2019**
11.	Distribution network use tariff				
a.	At the voltage level of 35 kV	EURO/MWh	11.2	11.8	12.2
b.	At the voltage level of 20 kV	EURO/MWh	29.1	30.6	31.7
2.	Average distribution tariff (used for all other owervoltage levels 10/6/0,4 kV)	EURO/MWh	35.7	37.5	38.9

Source: ERE

Retail prices for the tariff customer's supplied by OSHEE

The Universal Service Supplier (USS), by law, starting in 2018, should only supply electricity to the low-voltage customers (0.4 kV). Starting from 2012[19], any client that, regardless of the voltage level of the electricity network in which it is connected and has an annual energy consumption in excess of 50 million kWh, should be supplied either through the free market or by the Supplier of Last Resort (SLR).

Customers connected to the 35-kV network and above, as well as customers connected to the 20/10/6 kV network, starting January 1, 2017, are supplied either in the free market or by the Supplier of Last Resort (SLR).

But for the customers of the group 20/10/6 kV, who fail to secure suppliers in the free market due to the objective impossibility of system operators in accordance with DCM no. 449, dated 15.06.2016, the supply as a last resort of these customers is carried out on the same terms as the universal supply service at regulated prices.

[19] Law No.10485, dated 26.11.2011 "On some amendments and additions to the law no. 9072, dated 22.5.2003 'On the electricity sector", as amended, article 48, point 1.

These regulated prices for 2017, 2018 and 2019 are presented in Table 5.21.

Table 5.21 **Tariffs for medium voltage connected customers (Note 4)**

No	Medium voltage connected customers	Unit	2017		2018		2019	
			Off peak	Peak	Off peak	Peak	Off-peak	Peak
1.	Customers connected to the 20/10/6 kV network	EURO/ MWh	82.0	94.3	86.2	99.1	89.4	102.8
2.	2. Customers connected to the Medium Voltage and with metering in the Low Voltage	EURO/ MWh	92.4	106.6	97.2	112.1	100.8	116.3

Note: The exception of the group connected to the 20/10/6 kV grid are the bakehouses and the 10/6 kV flour-milling plants that are supplied at regulated prices.
Source: ERE

The electricity retail prices for end customers supplied by the Universal Service Supplier (USS), (which are the same in ALL) for the three years, 2017, 2018 and 2019 are presented in Table 5.22.

Table 5.22 **Tariffs for medium voltage connected customers (Note 4)**

No.	End customers supplied by Universal Service Supplier	Units	2017		2018		2019	
			Off peak	Peak	Off peak	Peak	Off-peak	Peak
1.	Bakehouses and flour-milling plants at 10/6 kV	EURO/ MWh	52.9	60.9	55.6	64.0	57.7	66.4
2.	Clients at 0.4 kV	EURO/ MWh	104.3	120.0	109.7	126.2	113.8	130.9
3.	Bakehouses and flour-milling plants at 0.4 kV	EURO/ MWh	56.6	65.1	59.6	68.5	61.8	71.1
4.	Households	EURO/ MWh	70.8	Not applic able	74.5	Not applic able	77.2	Not applic able
5.	Charges for electricity consumption in joint facilities (scale lightening, water pump, elevator)	EURO/ MWh	70.8	Not applic able	74.5	Not applic able	77.2	Not applic able

Source: ERE

There is also a fixed "zero" reading service fee for customers who have an active contract with OSHEE sh.a. but have no consumption during the same period. This tariff for 2017, 2018 and 2019 for this group has been around 1,5 - 1,6 EURO/contract/month.

Notes:

1. Price at peak is 15% higher than off-peak price wherever peak pricing applies.
2. The price for reactive energy is 15%of the active energy price.
3. Peak hour during which shall be applied the tariff for the consumed energy during the peak is: (a) November 1 - March 31 period from 18.00 to 22.00 (b) April 1 - October 31 from 19.00 to 23.00
4. The changes in Table 5.21 come only as a result of different ALL to EURO exchange rates in respective years
5. The changes in Table 5.22 come only as a result of different LEK exchange rates against the EURO

One should note that "Supplier of Last Resort" is a supplier (currently the state-owned OSHEE sh.a.) that provides universal service under regulated conditions, for a limited time, to the household and small non-household customers which have not managed to contract a supplier of their own or have lost their supplier.

This limited period is 2 years from the beginning of the supply contract by the SLR. The sale price of electricity supplied by the SLR is set only for customers connected to the 35-kV voltage level and is calculated by ERE on a monthly basis. ERE began to calculate this price from January 2018. For 2018 and 2019, the prices set by ERE are shown in Table 5.23.

Table 5.23 **Sales prices approved by ERE for the Supplier of Last Resort**

No. Months	Sales price approved by ERE for LRS 2018	2019
	EURO/MWh.	EURO/MWh.
11. January	90.9	152.3
2. February	74.5	113.2
3. March	74.5	108.9
4. April	74.5	111.1
5. May	74.5	110.7
6. June	77.0	106.3
7. July	100.8	103.7
8. August	100.8	103.7
9. September	100.8	104.1
10. October	125.4	113.9
11 November	125.4	119.3
12. December	119.3	134.7
Average selling price	94.8	115.2

Source: ERE

Unregulated market information

The two big public companies, the national Transmission System Operator of electricity, OST sh.a., and the holding company OSHEE sh.a.[20], that serves as Distribution System Operator (DSO), Universal Service Supplier (USS), Free Market Supplier (FMS) as well as the Supplier of Last Resort (SLR) for electricity, have bought electricity in the free market during 2019. The quantities and respective prices are presented in Table 5.24.

Table 5.24 **Electricity purchased from state companies OST sh.a. and OSHEE sh.a. during 2019**

Months	Quantity			Price			Value (excluding VAT)		
	OSHEE sh.a.	OST sh.a.	Total	OSHEE sh.a.	OST sh.a.	Averag e	OSHEE sh.a.	OST sh.a.	Total
	GWh			EURO/MWh			mm EURO		
January	388.7	11.2	399.9	89.8	81.7	89.6	34.9	0.9	35.84
February	173.0	11.4	184.5	69.8	71.9	69.9	12.1	0.8	12.90
March	259.3	10.8	270.0	64.5	48.3	63.8	16.7	0.5	17.24
April	236.5	9.6	246.1	62.9	49.6	62.4	14.9	0.5	15.35
May	127.3	11.4	138.7	70	56.8	68.9	8.9	0.6	9.55
June	140.7	52.0	192.7	53.4	46.6	51.6	7.5	2.4	9.94
July	126.5	0	126.5	62.2	0	62.2	7.9	0	7.87
August	141.4	0	141.4	62.2	0	62.2	8.8	0	8.80
September	230.9	0	230.9	68.5	0	68.5	15.8	0	15.82
October	210.7	0	210.7	73.2	0	73.2	15.4	0	15.43
November	136.6	0	136.6	80.7	0	80.7	11.0	0	11.02
December	0.0	38.3	38.3	0	58.4	58.4	0.0	2.2	2.24
TOTAL/AVER AGE 2019	**2,171.4**	**144.7**	**2,316.2**	**70.9**	**55.6**	**69.9**	**154.0**	**8.0**	**162.00**

Source: ERE, OST sh.a., OSHEE sh.a.

[20] Under unbundling process.

5

Table 5.25 presents the above data in a summary form for the whole year 2019.

Table 5.25 **Energy purchased from state companies OST sh.a. and OSHEE sh.a. during 2019**

Companies	Quantity	Value (excluding VAT)	Price
OSHEE sh.a.	2,171.4	154	70.9
OST sh.a.	144.7	8	55.3
Total/Average	**2,316.2**	**162**	**69.9**

Source: ERE, OST sh.a., OSHEE sh.a.

(f) Cross-border interconnections

Albania has six Interconnection lines with three out of four neighboring countries:

- 400 kV line Zemblak - Kardia (Greece)
- 400 kV line Tirana 2 - Podgorica (Montenegro)
- 400 kV line Tirana2 - Kosovo B (Kosovo)
- 220 kV line Koplik - Podgorica (Montenegro)
- 220 kV line Fierze - Prishtina (Kosovo)
- 150 kV Bistrica 1 - Igumenice (Greece).

The 400 kV Tirana2 (AL) - Kosovo-B (KO) is already constructed and the project is fully commissioned and ready to start operation. Besides the national Transmission System Operator, state company OST sh.a., owns and operates in total fifteen Substations (400 kV, 220 kV, and 150 kV) with a total installed capacity of 4096 MVA.

(g) Planned new projects

The TYNDP plan[21], of TSO includes the construction of the new 400 kV Interconnection Line Fier - Elbasan - Bitola (NM), as well as the extension of the 400-kV voltage level of Koman substation, to increase the transmission capacities toward Kosovo.

The interconnection line Albania - North Macedonia project includes:

- Construction of a new 400 kV transmission line Elbasan - Ohrid - Bitola, 151 km (56 km in Albania territory);
- Extension of the Elbasan2 Ss and installation of a new 120 MVAr shunt reactor.
- Construction of 68 km of new 400kV line, from Elbasan2 - Fier.
- Extension of Fier Ss, with 1 new AT-400 MVA.

Renewables

(a) Overview of sector's development

The National Energy Strategy[22] considers increasing the use of RES technologies, based on least-cost planning and environmental protection principles, resource diversification, and climate change prevention as one of the key outcomes to be achieved in the energy field. This strategy sets the target for renewable energy consumption versus total energy consumption to reach 42% in 2030. The National Action Plan for Renewable Energy Sources (NAPRES[23]) for 2018-2020 has also been approved. It sets the roadmap for achieving the national target on the percentage of energy from renewable sources consumed in the electricity (RES-E), transport (RES-T) and heating and cooling (BREH&C) sectors by 2020. The NAPRES also sets quantitative and specific benchmarks for renewable energy generation technology.

In this context, to forerun reforms in the electricity sector and achieve the 38% target of RES in the FGEC[24], the revised NAPRES for the remaining period 2018-2020, the following steps are recommended:

- Effective measures for the adoption of the secondary legation provided by law no. 7/2017 and the inclusion and diversification of renewable resources in Albania;
- Wider technical-economic analysis related to the interests of all renewables market operators in applying "support schemes" to promote RES without distinction; and

[21] Albanian TSO, Updated Ten Year Network Development Plan 2018-2028. On line: file:///C:/Users/user/Downloads/REWS_OST_112018.pdf
[22] Decision of the Council of Ministers No. 480, dated 31.7.2018 "On the approval of the National Energy Strategy for the period 2018-2030".
[23] National Action Plan for Renewable Energy Sources.
[24] Final Gross Energy Consumption.

• Strengthening the legislation on biofuels in the transport sector in terms of sustainability criteria, information / reporting, and measures to promote their marketing to the end consumer;

During 2018 renewable generation sources have been added which currently account to about 32% of our total generation resources. (ERE, AR 2018)

(b) Latest legislation, incentives and national RES policy

Law no. 7/2017 which was enacted in 2017, "On the promotion of energy use from renewable resources", partially aligned with Directive 2009/28 / EC of the European Parliament and of the Council of 23 April 2009 repealing previous Law no. 138/2013 "On Renewable Energy Sources", as amended, which was also the first integral law addressing the problems with these forms of energy.

The new 2017 law retained some mechanisms and institutions as did the old law of 2013, such as the obligation on the institutions responsible for drafting a National RES Action Plan, which is periodically reviewed, the existence of a RES responsible agency (which nonetheless had not yet been created by 2017, but its role is played by the Free Market Supplier), as well as the existence of guarantees of origin, an electronic document that has the sole function of proving to the final customer that part or all of the amount of energy used is generated by RES.

But the law changed support measures for RES electricity generation, simplified and in some cases eliminated the incentives to use solar water heating systems for the production of hot water including tax exemptions for their import and some specific provisions regarding the use of RES in transport, and introduced the concept of net energy metering.

According to this law, Albania's overall RES energy target in gross final energy consumption is 38 percent in 2020. According to the guidance of this law, the average in 2017-2018 gross final energy consumption should be 35.6%.

The legal framework offers:

(a) **The obligation to purchase electricity produced by electricity priority generators** that do not benefit from the support scheme under the contract of difference's support scheme, is considered a public service obligation and hence is charged to an ERE licensee.

(b) **Network access.** Transmission and distribution of electricity from RES is guaranteed, and producers producing electricity from RES have the advantage of access to electricity networks.

Support schemes.

Who benefits from the support schemes.

Both the 2013 and the 2017 law's provide support to all RES producers who are considered as "Priority Producers".

The 2013 law considers "Priority Producer", any producer of electricity from renewable sources, with installed capacity up to 15 MW for all power plants built by the company, which benefits from a fixed sales tariff mechanism (feed-in tariff). According to the 2017 law, the upper limit of 15 MW of installed capacity per generating unit was maintained only for a "Priority Producer" in the case of hydropower while for any other RES power producer this upper limit was removed. Also, the concept of a new group of producers called "Existing Priority Producers" was introduced, known as priority producers, from hydro resources, that regardless of the moment of signing the contract with the contracting authority, are equipped with a 'Plant Acceptance Certificate' in accordance with the relevant legislation, until the 31st of December 2020.

What are the types of support schemes?

The 2013 law theoretically provided support to all producers of electricity from renewable sources, but practically the bylaws enforced provisions only for hydropower. The support was provided in the form of Feed-in annual fixed tariffs that benefited all electricity producers from hydropower plants installed up to 15 MW each, if they did not choose to sell power in the free market. Decision of the Council of Ministers

Nr. 125, dated 11.2.2015 "On approval of the methodology for calculating the fix tariff for electricity, for the year 2015, that should be paid to electricity generators from the hydropower plants", followed by the Council of Ministers Decision No. 1033, dated 16.12.2015 which defined the "Methodology for calculating the fix tariff for electricity, that should be paid to electricity generators from the hydropower plants".

The 2017 law provides the following main supportive measures:

1. It gives the right to the Council of Ministers, upon the proposal of the Minister, **to take measures** that they deem reasonable to promote the use of electricity by RES in order to achieve the national objective of renewable energy. The law does not make it very clear what these measures are.

2. Feed-in Tariff for energy generated from small renewable sources. Electricity generated by priority generators with installed electricity capacity of up to 2 MW, and in the case of wind turbines with a capacity of up to 3 MW, is purchased by the Renewable Energy Operator at a fixed price calculated according to the approved methodologies by the Council of Ministers. This price, in the case of energy produced from hydropower, shall not be lower than the price approved by the ERE in 2016. This price shall, in the case of PV and wind technology, serve as the price level on the basis of which the beneficiaries of the contract for difference support scheme will be selected, as one of the elements of the competitive procedure.

3. Contract for Difference (CfD). The law introduced, as the main incentive mechanism for RES electricity generation, support under the "Contract for Difference". This support is based on a variable remuneration, calculated as the difference between the price at which the producer of renewable energy is declared the winner in a competitive bidding process (strike price) and the electricity market price (reference price). The CfD will have a maximum duration of 15 years. However, by January 2020, no such competitive process had yet taken place, so no one has benefited from the CfD scheme.

4. Feed-in Tariff for energy produced by "Existing Priority Producers". Electricity produced by existing priority generators is purchased by the Renewable Energy Operator at a fixed price calculated according to the methodologies approved by the Council of Ministers.

"Net energy metering scheme" is a scheme that makes the bidirectional measuring possible for small and medium enterprises or household customers, who have installed a total capacity for the production of electricity from wind or solar energy under 500 kW, which cannot be dispatched. These customers generate a part or all the energy for their own needs and can introduce the surplus energy produced into the distribution grid.

But the above bylaw only came out in June 2019 and applies only to solar (and not wind) plants. However, this legal framework has not yet become operational as 6 months have been left for OSHEE to propose to the ERE and MEI, changes to the Distribution Code and the Metering Code, which may be affected by the deployment of PV for self-consumption, and then another non-specified time which is needed by the ERE to adopt the methodology for determining the purchase price of electricity produced. Until the Methodology is adopted, the surplus energy, which exceeds the monthly consumption, will be passed on to the Universal Service Supplier without any compensation to the self-producers.

Customs duties exemptions

According to law no 8987, dated 24.12.2002 "On creation of facilities for the construction of new power capacity" and related Council of Minister's decisions, are exempt from customs duties, machineries and equipment, which are part of an electricity generation facility with an installed power of not less than 5 MW per source, using liquid or solid fuels and without limitation on other renewable sources of production.

As far as non-technical barriers are concerned prevent or delay RES development.

There are no specific issues worth mentioning other than the overall assessment of the situation for doing business in Albania. Hence, no non-technical barriers have been identified specifically for RES development.

Energy Efficiency and Cogeneration

(a) National targets

The National Energy Strategy[25] considers energy efficiency improvements on residential, services, transport, agriculture and industry sectors as one of the main results to be achieved in the energy field. This strategy sets the target for the Albanian economy and society to achieve a level of energy saving versus total consumption of 15% in 2030.

The 2015 Energy Efficiency Law[26] did not set targets, but specified[27] that they would be set by the National Action Plan for Energy Efficiency (NAPEE) 2nd and 3rd NAPEE for Albania, 2017-2020[28] analysis, concluded that "the cumulative energy savings achieved by the end of 2015 are estimated at 16.4 ktoe, which is about 0.9% of the EU Directive[29] reference consumption.

This was compared with the (extrapolated) target of 5.2% and, while the analysis could not cover all the actions implemented so far, the gap is clearly significant. Albania maintains a target of cumulative energy savings equivalent to 9% of the EU Directive[30] reference consumption (equivalent to 168 ktoe, in terms of final energy consumption, or 10 times more than cumulative savings estimated to have been achieved by the end of 2015) by the end of 2018." The targets for 2018 and 2020, based on the measures included in this NAPEE, are presented in Tables 5.26 and 5.27 below. The first table, Table 5.26 specifically stops at the final energy savings (also presented graphically in Figures 5.31 & 5.32), broken down by sectors, while the Table 5.27 shows the primary and final energy savings.

Table 5.26 **National guiding objectives in final energy savings per sector according to NAPEE 2017-2020**

Targets as per relevant sectors	Estimates of energy savings by 2018 (ktoe)	Estimates of energy savings by 2020 (ktoe)
	From measures (PL)	From measures (PL)
Houses	10.66	37.43
Services	6.27	16
Industry	3.7	6.9
Transportation	14.2	49.49
Horizontal	3.7	13.9
Total (equivalent units):	38.5	123.7
Total (GWh):	447.8	1,438.6
Percentage (%) compared to baseline scenario	2.1% (compared to baseline scenario 2018)	6.8% (compared to baseline scenario 2020)

Source: NAPEE 2017-2020

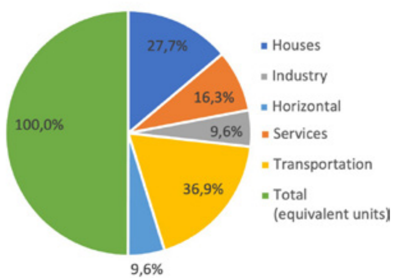
[25] Decision of the Council of Ministers No. 480, dated 31.7.2018 "On the approval of the National Energy Strategy for the period 2018-2030".
[26] Law No. 124/2015 "On energy efficiency".
[27] Ibid., Article 6, paragraph 3.
[28] Council of Minister Decision No. 709, dated 1.12.2017 "On the approval of the second and third National Action Plan on Energy Efficiency for Albania".
[29] Directive 2006/32/EC on energy end-use efficiency and energy services, still in force for Albania.
[30] Directive 2006/32/EC on energy end-use efficiency and energy services, still in force for Albania.

Table 5.27 **Overview of estimated / realized energy savings targets, both for primary and final energy**

	Primary energy		***Final energy***		
			EU Directive: 2006/32/EC		***EU Directive: On the energy performance of buildings***
	Target (ktoe)	*Estimated / Realised Energy Savings (ktoe)*	*The target of final energy savings, as defined in the first / second NAPEE, or in the latest version if revised (in absolute terms (ktoe))*	*Final energy savings achieved (2015), or forecast (by 2018) (in absolute terms (ktoe))*	*Target for houses s with almost zero energy consumption (all new buildings, percentage (%) or shrinking energy performance requirements)*
2012	N/A	N/A	26	10.5	
2015	N/A	N/A	97*	16.4	#
2018	40	-	39	-	
2020	154	-	124	-	To be confirmed

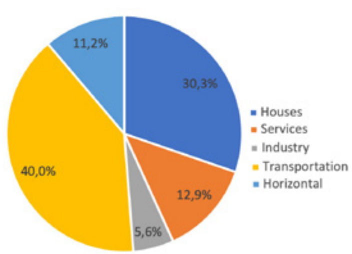
Source: NAPEE 2017-2020

Figure 5.31 **Estimates of energy savings by 2018 [ktoe]**



Source: NAPEE 2017-2020

Figure 5.32 **Estimates of energy savings by 2020 [ktoe]**



Source: NAPEE 2017-2020

(b) Incentive-based initiatives in the building sector (planned or already in place)

The heating of buildings in the public service and residential sectors is generally of poor performance. Albania has done little related to energy efficiency measures. Hence, there is a great potential for energy efficiency improvements.

According to Energy Community Secretariat, "despite the formal strengthening of the legal and institutional framework for energy efficiency, little was achieved by Albania to adopt the missing by-laws implementing the Energy Performance of Buildings Directive and update legislation to transpose Directive 2012/27/EU on energy efficiency. Albania thus remains non-compliant in many areas.[31]"

No incentive-based initiatives are in place yet and there are not any energy service companies (ESCOs) schemes. The government has postponed the establishing of an Energy Efficiency Fund required by the law[32] and has some dilemma about the efficiency of such mechanism.

[32] https://www.energy-community.org/implementation/Albania/EE.html
[33] Law No. 124/2015 "On energy efficiency".

But some policy measures are in place required by the laws for energy efficiency and energy building performance, which are presented below:

Table 5.28 **Energy efficiency policy measures**

Required by the law:	Policy measure	Application field / entity	Start period	Notes
On energy efficiency	Mandatory energy audit	(a) any legal person, public or private, which is categorized as a big energy consumer; (b) all natural and / or legal persons applying for a program financed by the Energy Efficiency Fund to promote and improve energy efficiency; (c) at any time before a building, industrial site and other facilities being evaluated, put into operation and / or rebuilt or subjected to substantial renovation.	End of 2015	The big energy consumers, is a final consumer, which, based on the data of an audit process, results in annual energy consumption greater than the equivalent of 3 million kWh per year.
	Mandatory measures for energy efficiency improvements	Any legal entity that is categorized as a big energy consumer and subject to mandatory auditing should, within two years of receiving the audit results, take measures and take recommended actions to improve energy efficiency.	End of 2015	
	Mandatory energy manager	Big energy consumers	End of 2015	
	Mandatory energy consumption data	Big energy consumers	End of 2015	
	Mandatory energy consumption data if required	Others energy consumers	End of 2015	
For energy building performance				
	Implementation of the requirements of the National Building Energy Performance Calculation Methodology and analysis of the possibility of using high energy performance systems	Entity that owns or will have ownership or administration responsibility for this building (When designing a new building or when a building has to undergo significant renovation);	End of 2016	
	Assessment of the possibility of using high energy efficient alternative systems should be carried out in advance	If during the phase of restructuring or renovation of buildings a replacement or renovation of the building's technical system is planned;	End of 2016	
	Mandatory certification of energy performance of buildings	a) all buildings or units of buildings which are to be sold or rented; b) all buildings to be constructed or to undergo significant renovation; c) all buildings in use by a public authority or by institutions providing a public service and frequently frequented by the public, having an area of over 500 m^2. Starting July 9, 2018, the requirement for the above limit of usable area will be reduced to 250 m^2.	End of 2016	

Source: NAPEE 2017-2020

(c) EU funded (or otherwise funded) energy efficiency programs in the building sector

According to the Agency for Energy Efficiency[34] (AEE) some projects and programs progressed in 2017-2019. These include the following:

The project "On Energy Auditing of Public Buildings" financed by the state budget aims to create the inventory of public building stock and to place data on a server of the AEE by naming and codifying them in the national electronic register, as well as to audit the entire stock of buildings for three years and to register it on the server with the data related to the costs effective analysis of their renewal.

The project financed by KfW Development Bank, "Promotion of Renewable Energies and Energy Efficiency" that aimed the rehabilitation of the dormitories of Students City No. 1 and Student City No. 2 according to the Energy Efficient principle, including interior restructuring and kitchen equipment. The target of this project was to reduce the energy performance of the dormitories to 75 kWh/m^2 per year.

The project "Development of a Financing Mechanism for Energy Efficient Public Buildings in Albania" aims to inform and facilitate decision-making for sustainable financing mechanisms for energy efficiency (EE) in the public buildings sector.

Smart Energy Municipalities is a project financed by the Swiss Embassy in Tirana and aims to support selected Albanian municipalities to manage energy in a sustainable manner and to implement the national energy policy at local level.

Study and Expert Fund measure on "Energy Management in Municipalities" by Germany/ GIZ, strengthen partner capacities in energy efficiency and to plan, prioritize and implement selective energy efficiency measures at the municipal level in 12 municipalities.

Regional Program: "ORF Energy Efficiency" by GIZ. The relevant political and civil society actors in South Eastern Europe increasingly take advantage of regional networks for the implementation of EU standards in the field of climate protection.

(d) Cogeneration: Regulatory framework, installed capacity

Albania does not yet have a co-generation regulatory framework.
UNIDO reports[35] about a project that started in 2011 in Albania aiming to increase the use of biomass in industrial energy consumption for productive use through demonstrated use of modern biomass technologies in Small and Medium-sized Enterprises (SMEs) in the olive oil industry.

The project aim is to increase the use of biomass in 15 pilot SMEs, with a capacity of about 1-1.5 MW and costing approximately € 4.5 million. No other projects of significant size are reported.

(e) Planned new major projects

Besides Vlora gas fired TPP, there are three Waste Incinerators under construction in Elbasan, Tirana and Fier, which shall be used for power generation as well. Their installed capacities are respectively 2,9 MW, and 3,85 MW each for the last two, totaling 10,6 MW.

[34] First and Second Annual Report under the Energy Efficiency Directive.
[35] https://open.unido.org/projects/AL/projects/120536

5

BOSNIA HERZEGOVINA

Bosnia Herzegovina

Economic and Political Background

There are two autonomous entities that form Bosnia and Herzegovina: the Federation and the Serb Republic. The GDP of Bosnia's Federation fell by a real 2.5% year-on-year in the fourth quarter of 2020, after contracting by 3.9% in the preceding quarter, as the entity's statistical office announced. On a quarterly comparison basis, the Federation's GDP increased by 2.8% in October-December, after rising by 5.6% in July-September.

The largest decrease of gross value added in real terms was recorded in the sectors of wholesale and retail, repair of motor vehicles and motorcycles, transportation and storage, accommodation and food service activities, arts, entertainment and recreation. In the fourth quarter of 2019, the Federation's GDP grew by 2.3% year-on-year in real terms.

The GDP of Bosnia's Serb Republic fell by a real 2.4% year-on-year in the fourth quarter of 2020, after contracting by 3.4% in the preceding quarter, as the entity's statistical office announced. In seasonally-adjusted terms, GDP increased by 2% on a quarterly comparison basis in October-December, after adding 3.5% in July-September. In the fourth quarter of 2019, the entity's GDP grew by 2.6% year-on-year in real terms.

The biggest real annual drop of gross value added in the fourth quarter of 2020 was recorded in arts, entertainment and recreation, other service activities, followed by mining and quarrying, manufacturing, electricity, gas, steam and air conditioning, water supply, sewerage, waste management and remediation activities.

IMF estimates that Bosnia's GDP will expand by 5.0% in 2021, significantly higher than -6.5% in 2020.

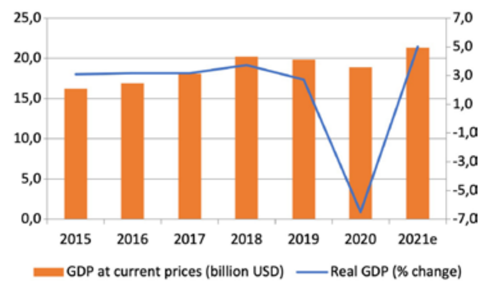
When it comes to political and administrative status, Bosnia and Herzegovina can be situated among world's most complex countries. The division of the country into two entities is just a tip of the political iceberg. Serb Republic's administrative division to 64 municipalities serves as a political mechanism of centralization of this entity, centered on the city of Banja Luka. The administrative solution for Federation of Bosnia and Herzegovina results in furthering the political social fragmentation.

Table 5.29 **Main Economic Indicators for Bosnia and Herzegovina Over 2015-2019e**

	2015	2016	2017	2018	2019 proj.
GDP growth	3.1	3.1	3.2	3.6	3.0
Inflation (average)	-1.0	-1.1	1.2	1.4	1.0
Government balance/GDP	0.7	1.2	2.6	2.3	1.0
Current account balance/GDP	-5.1	-4.7	-4.3	-3.7	-5.0
Net FDI/GDP [neg. sign = inflows]	-1.8	-1.8	-2.1	-2.6	-3.0
External debt/GDP	62.9	63.8	61.1	61.0	n.a.
Gross reserves/GDP	30.1	31.9	33.5	35.3	n.a.
Credit to private sector/GDP	55.0	54.3	55.6	55.2	n.a.

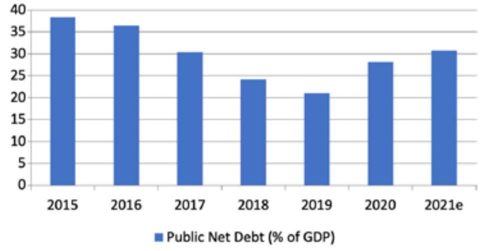
Source: EBRD's Transition report 2019-2020

Figure 5.33 **Bosnia's GDP and its annual GDP growth**



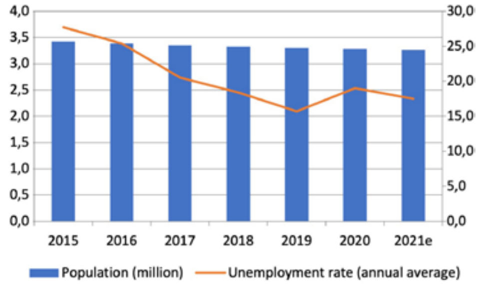
Source: IMF World Energy Outlook (October 2020)

Figure 5.34 **Bosnia's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.35 **Bosnia's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy

By signing the Treaty Establishing the Energy Community, Bosnia and Herzegovina accepted a list of obligations related to the standards of the EU energy market with which it will hopefully integrate in due course. This is to be achieved by the gradual transposition of the EU acquis, which means the implementation of the relevant EU directives and regulations pertaining to electricity, gas, security of supply, environment, competition, renewable energy sources, energy efficiency, oil, statistics and infrastructure. The basic strategic goal of Bosnia and Herzegovina is to speed up the harmonization of its legislation with the acquis, and transpose and implement the obligations assumed under the Energy Community Treaty.

In the second half of 2018, "The Framework Energy Strategy of Bosnia and Herzegovina until 2035" was adopted by the Council of Ministers (the State Government). This document is based on two entities strategic documents (the Framework Energy Strategy of the Federation of Bosnia and Herzegovina and the updated Energy Strategy of Republic of Srpska) and work of the joint working group for this task. This is the first state strategic document in the field of energy. Due to the complex structure of BiH and competencies the Framework Energy Strategy is not a strategy, but a framework for a strategy. Nonetheless, this document is very important because all levels of the country (State and Entities and District) were involved in its preparation and the document was approved by the Council of Ministers (the State Government).

Priorities from the Framework Energy Strategy are as follows:

- Efficient use of resources
- Secure and affordable energy
- Energy efficiency
- Energy transition and environmental responsibility
- Development and harmonization of regulatory and institutional framework

Harmonization of Bosnia and Herzegovina's legislation with the EU acquis is a complex assignment, considering that it implies the comprehensive and essential changes to the energy sector, as well as overall sector reform. Furthermore, it is necessary to make the relevant institutions capable of establishing and implementing a new legal and regulatory framework. This segment is particularly sensitive in Bosnia and Herzegovina, considering the complexity of political, institutional and social risks[1].

As previously mentioned, transposition and implementation of acquis in Bosnia and Herzegovina has been significantly delayed. Severe deadlines have already expired and nine actions[2] have been instigated against Bosnia and Herzegovina by the Energy Community Secretariat. In the context of strategic and operational activities in the forthcoming period, a due diligence process for the harmonization of the legislation at entity and at the level of Bosnia and Herzegovina, with the EU acquis should be undertaken. These activities are necessary for the preparation of action plans and for implementing the further harmonization of legislation.

Governmental institutions

Bosnia and Herzegovina (BiH) is a state consisting of two administrative units (two

1 "Framework Energy Strategy of Bosnia and Herzegovina until 2035", 2018
2 Annual Implementation Report 2018/2019, Energy Community Secretariat, November 2019

entities), the Federation of Bosnia and Herzegovina (FBiH) and the Republic of Srpska (RS), and an internationally supervised district of Brčko (Brčko District) as a separated administrative unit. The administrative structure of Bosnia and Herzegovina is reflected in the energy sector.

According to the legal framework, the responsibility at state level is, among other things, the regulation of inter-entity transport, which includes the transport of energy. Also, foreign policy and fulfillment of assumed international obligations is the responsibility of state level institutions. The state level is responsible for the transmission network and electric power system operations and mainly for the wholesale electricity market. According to the legal framework, the entities have their own legislation for energy sub-sectors (electricity, natural gas, energy efficiency, renewable energy, oil and oil products etc.).

Bearing in mind the above, the relevant institutions in the energy sector are the following:

The Ministry of Foreign Trade and Economic Relations of Bosnia and Herzegovina (MOFTER) as a part of the Council of Ministers (the State Government) is the key institution at state level in the energy sector. MOFTER is responsible for defining policies and basic principles and for the coordinating activities and harmonization of entity level plans relevant for international relations. MOFTER has also competencies in the area of concessions of border rivers (use of water resources), as well as when the subject of concession is in the territory of both entities.

The Federal Ministry of Energy, Mining and Industry (FMERI) (entity ministry), holds authority in the fields of industry, energy, mining, geological research and entrepreneurship. FMERI is, among other responsibilities, responsible for the generation, distribution and electricity supply in the entity of the Federation of Bosnia and Herzegovina.

The Ministry of Industry, Energy and Mining of Respublika Srpska (MIER) among other responsibilities holds authority in the fields of industry, energy, mining, and geology. MIER is also responsible for the generation and distribution of electricity in the entity of Republic Srpska.

The regulatory framework of the energy sector follows the internal structure of Bosnia and Herzegovina as established by the Constitution. The State Electricity Regulatory Commission in Bosnia and Herzegovina, the Regulatory Commission for Electricity in the Federation of Bosnia and Herzegovina and the Regulatory Commission for Energy of Republic of Srpska constitute the regulatory framework which was established by the adoption of national and entity laws in the field of energy.

The State Electricity Regulatory Commission (SERC) regulates the electricity transmission system in Bosnia and Herzegovina (110 kV and above) and has jurisdiction and responsibility over the transmission of electricity, transmission system operations and international electricity trade. SERC also regulates the distribution and supply of electricity in Brčko District of Bosnia and Herzegovina.

The Regulatory Commission for Energy in the Federation Bosnia and Herzegovina (FERK), among other responsibilities has jurisdiction on the following: defining the energy prices for the supply of non-eligible customers, market monitoring, defining of tariffs for distribution systems users, licenses for generation, distribution and supply non-eligible customers, issuing the preliminary construction permits and licenses for usage of power facilities, except the facilities for power transmission. FERK also regulates oil activities.

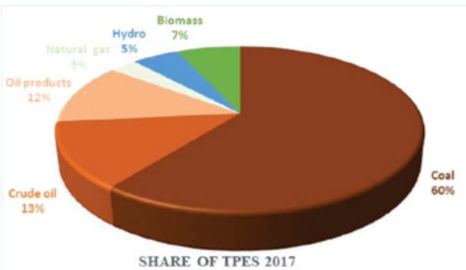
The Regulatory Commission for Energy of the Republic of Srpska (RERS) among other responsibilities has jurisdictions for: monitoring and regulation of relationships between generation, distribution and customers of electricity including traders of electricity, determination of tariff rates for distribution system users and tariff rates for non-eligible customers, licensing for generation, distribution and trade of electricity, regulates gas activities in RS, and has regulatory competences within the scope of the oil and oil derivatives sector.

Energy Demand and Supply

National Energy Demand and Supply

After reaching the post-war maximum of total primary energy supply in 2011 (7,2 Mtoe) when the pre-war supply (7,02 Mtoe) was exceeded and following 15 years of continued growth there has been a three-year supply decline that "stopped" in 2014. In 2017, the total primary energy supply of BiH was 6,8 Mtoe (Figure 5.36). This was on the level of 2016 and implies a growth of 12% compared to 2015[3].

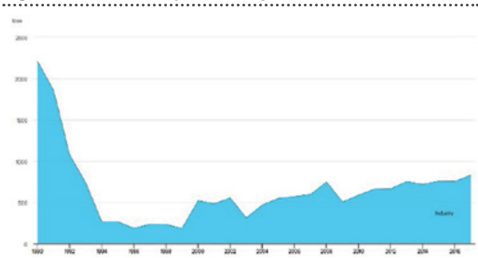
Figure 5.36 **Share of source in TPES 2017 for Bosnia and Hezegovina[8]**



Source: International Energy Agency, www.iea.org

Coal was still the main domestic energy resource as shown in Figure 5.36. The share of coal in the country's TPES was 60%.

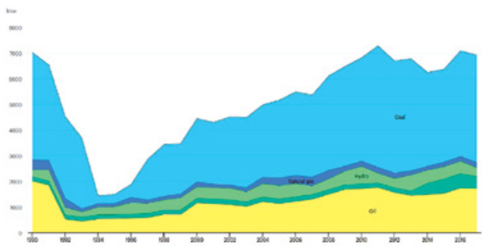
Figure 5.37 **Industry consumption**



Source: International Energy Agency, www.iea.org

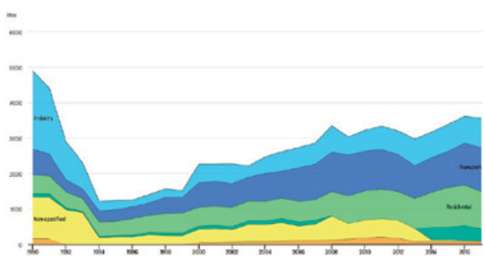
The share of transport in total energy consumption is the highest of the last 20 years. In 2017 this share was 35% of total consumption. However, if we look only at the total consumption of industry over the last 30 years (Figure 5.38), we see a different, less favorable, picture of Bosnia and Herzegovina's development. The total consumption of the industry was at 37% of pre-war consumption. In the same period consumption of transport was 70% higher compared to the 90s.

Figure 5.38 **Total primary energy supply (TPES) by source, Bosnia and Herzegovina 1990-2017**



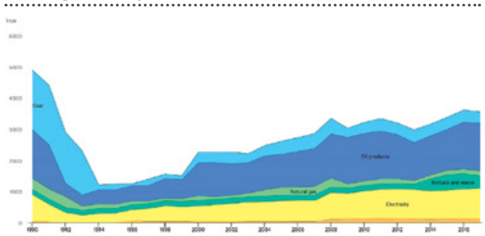
Source: International Energy Agency, www.iea.org

Figure 5.39 **Total final consumption of Bosnia and Herzegovina by sectors**



Source: International Energy Agency, www.iea.org

Figure 5.40 **Total final consumption of Bosnia and Herzegovina by source**



Source: International Energy Agency, www.iea.org

Table 5.30 is presenting the total energy balance of Bosnia and Herzegovina for the period 2014-2017[4].

[3] International Energy Agency, www.iea.org
[4] Agency for Statistics of Bosnia and Herzegovina, http://bhas.gov.ba/data/

Table 5.30 **Total Energy Balance of Bosnia and Herzegovina**

Bosnia and Herzegovina,Total energy balance				
ktoe	2014	2015	2016	2017
Primary production	4.327	4.397	4.773	4.642
Coal	3.073	3.165	3.521	3.612
Crude oil				
Oil products				
Natural gas				
Hydro	510	477	487	345
Biomass	744	755	765	685
Electricity				
Heat				
Import	3.147	3.317	3.436	3.491
Coal	989	958	938	1.009
Crude oil	970	947	949	874
Oil products	764	901	1.099	1.114
Natural gas	152	177	185	200
Hydro				
Biomass		1		6
Electricity	272	333	265	288
Heat				
Stock changes	2	-280	-106	-169
Coal	-47	-195	-23	-163
Crude oil	57	-2	-78	22
Oil products	-8	-71	-5	-28
Natural gas				
Hydro				
Biomass		-12		
Electricity				
Heat				
Export	-1.451	-1.319	-1.382	-1.195
Coal	-357	-313	-324	-270
Crude oil				
Oil products	-305	-239	-220	-252
Natural gas				
Hydro				
Biomass	-274	-250	-250	-227
Electricity	-515	-517	-588	-446
Heat				
Gross inland consumption	6.025	6.115	6.721	6.769
Coal	3.658	3.615	4.112	4.188
Crude oil	1.027	945	871	896
Oil products	451	591	874	834
Natural gas	152	177	185	200
Hydro	510	477	487	345
Biomass	470	494	515	464
Electricity	-243	-184	-323	-158
Heat	0	0	0	0

Source:Agency for Statistics of Bosnia and Herzegovina, http://bhas.gov.ba/data

Energy mix

Generally, the energy sector of Bosnia and Herzegovina is characterized by significant domestic coal resources and the total absence of oil and natural gas production (Table 5.30). Coal production in conjunction with hydrological reserves enables Bosnia and Herzegovina to export significant quantities of electricity. But Bosnia and Herzegovina is totally dependent on imported oil and gas.

Degree of Energy Dependence

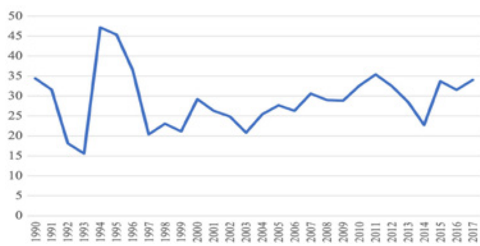
As presented in Table 5.31 and shown in Figure 5.41, the average energy dependency on imported sources in BiH was 29% of the energy consumed during 2000-2017 and was 31% of the energy consumed in the period of 2010-2017. The percentage values in last three years (2015-2017) are higher than the average energy dependency of around 29% of the energy consumed over the period 2000-2017.

Table 5.31 **Energy imports, net (% of energy use)**[5]

Year	1990	2000	2005	2010	2011	2012	2013	2014	2015	2016
%	34,39	29,23	27,69	32,56	35,37	32,45	28,46	22,73	33,69	31,52

Source:https://data.worldbank.org/indicator/ (for the data from 1990 until 2014) and https://www.statista.com/statistics/691227/dependency-on-energy-imports-in-bosnia-and-herzegovina/ (for the data from 2015 until 2017)

Figure 5.41 **Net Energy imports (% of energy use)**



Source:https://data.worldbank.org/indicator/ (for the data from 1990 until 2014) and https://www.statista.com/statistics/691227/dependency-on-energy-imports-in-bosnia-and-herzegovina/ (for the data from 2015 until 2017)

[5] https://data.worldbank.org/indicator/ (for the data from 1990 until 2014) and https://www.statista.com/statistics/691227/dependency-on-energy-imports-in-bosnia-and-herzegovina/ (for the data from 2015 until 2017)

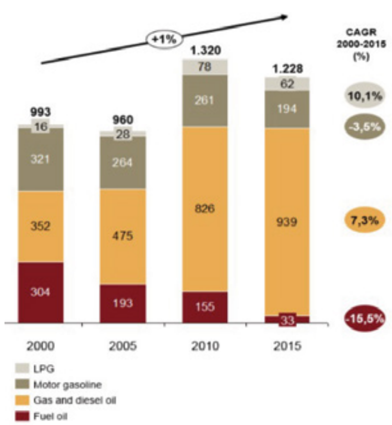
The Energy Market

Oil and Petroleum Products

(a) Oil supply and demand

Production of petroleum products in Bosnia and Herzegovina for 2018 reached 701.321 tons, while the amount of petroleum products available for supply stood at 1.639.585 tons. The final consumption in 2018 was 1.504.929 tons. The final energy consumption share in the total final consumption of petroleum products was 93% and the final non-energy consumption share was 7%. In the total final energy consumption of 1.401.257 tons of petroleum products in 2018, the largest share belonged to the transport sector (85.7%), households participated with 1.8%, industry with 6.6%, while the other, construction and agriculture sectors, participated with 5.9%. Figure 5.42 shows the annual demand for petroleum products for the period of 2000-2015, while Table 5.32 provides detailed data related to petroleum products for 2016, 2017 and 2018.

Figure 5.42 **Annual demand for petroleum products in Bosnia and Herzegovina (kt/year)**



Source:"Framework Energy Strategy of Bosnia and Herzegovina until 2035", 2018

(b) Oil imports/dependence

Bosnia and Herzegovina does not have a domestic production of crude oil and imports all necessary quantities. Generally, Bosnia and Herzegovina imports crude oil and refines a variety of petroleum products.

Yearly data (2016-2018) related to imports of crude oil is shown in Table 5.32.

Table 5.32 **Bosnia and Herzegovina, Crude Oil and Feedstock Balance** [6]

t	2016	2017	2018
Available for Supply	852.459	877.619	708.569
Production	-	-	-
Import	929.098	856.090	694.710
Export	0	0	0
Stock exchange	-76.639	21.529	13.859

Source:Energy statistics: Oil, Petroleum products, Agency for Statistics of Bosnia and Herzegovina, 2019

(c) Downstream and midstream sectors infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

Imported crude oil is processed in two oil refineries. The first one is the "Rafinerija nafte Brod" and is used for petroleum processing and production of petroleum products (gasoline, diesel, bitumen, LPG, fuel oil, sulphur) and the second one is the "Rafinerija ulja Modriča", which produces motor oil and various special purpose oils for the industry and other commercial purposes.

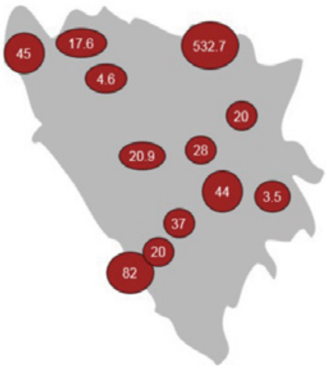
Over 90% of the processed products in the aforementioned refineries are distributed in the local market6. The petroleum products retail network is characterized by a large number of small retailers that own less than 5 petrol stations, and make up about 75% of the market. The highest consumption of petroleum products is in the transport sector, with motor gasoline and diesel used the most.

(d) Security of supply

Bosnia and Herzegovina depends entirely on imports for its oil and hence it maintains a high degree of stocks of crude oil and petroleum products. Bosnia and Herzegovina has a total of approximately 800.000 m³ of storage capacity for crude oil and derivatives, of which about 533.000 m³ are located in the "Rafinerija nafte Brod" oil refinery and 82.000 m³ in the port of Ploče operated by "Naftni terminali Federacije". The storage capacities for crude oil and derivatives in Bosnia and Herzegovina are presented in Map 5.3.

[6] Energy statistics: Oil, Petroleum products, Agency for Statistics of Bosnia and Herzegovina, 2019

Map 5.3 **Storage capacities (m^3) for crude oil and derivatives in Bosnia and Herzegovina[6]**

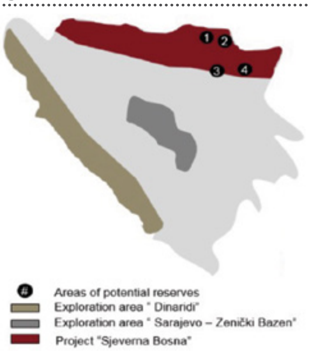


Source: "Framework Energy Strategy of Bosnia and Herzegovina until 2035", 2018

(e) Planned new projects

Some activity in geological exploration is in progress, but at a very low level. There are announcements that the governments (Government of Federation of Bosnia and Herzegovina[7] and Government of Republic of Srpska) are commencing with some activities related to hydrocarbon exploration. The selected hydrocarbon exploration areas are shown in Map 5.4.

Map 5.4 **Areas of hydrocarbon exploration in Bosnia and Herzegovina**



Source: "Framework Energy Strategy of Bosnia and Herzegovina until 2035, 2018

Table 5.33 **Bosnia and Herzegovina, Total Petroleum Products Balance**

	2016	2017	2018
Available for Supply	1.667.585	1.668.840	1.639.585
Production	823.853	862.784	701.321
Import	1.069.860	1.089.737	1.131.213
Export	220.313	257.071	227.839
Stock exchange	-5.815	-26.610	34.940
Transformation input	30.596	30.942	19.168
Thermal power plants	10.993	11.138	8.438
District heating plants	15.863	14.689	8.025
Auto-producers	3.740	5.115	2.705
Consumption in energy sector	138.167	127.931	115.488
Final consumption	1.498.822	1.509.967	1.504.929
Final non-energy consumption	79.545	66.122	103.672
Final energy consumption	1.419.277	1.443.845	1.401.257

Source: Energy statistics: Oil, Petroleum products, Agency for Statistics of Bosnia and Herzegovina, 2019

Natural Gas

(a) Natural gas Supply and Demand

Natural gas as an energy source in gross domestic consumption has a low share of total consumption for Bosnia and Herzegovina (2-3%). One of the reasons is that Bosnia and Herzegovina does not have domestic production of natural gas and does not have any installed thermal power plant gas capacities in the generation mix, which in practice represents larger consumers. The imports of natural gas to Bosnia and Herzegovina for 2018 amounted to 247.012.000 Sm^3. Natural gas consumption in the energy sector is 61.672.000 Sm^3. In a final natural gas consumption of 181.940.000 Sm3 in 2018 the industry participated with a share of 59%, households with 24% and other consumers with 17%. Historical data of natural gas consumption in Bosnia and Herzegovina by sector is presented in Figure 5.43.

[7] The end of May 2020 is the deadline for companies exploring oil and gas in the Federation of Bosnia-Herzegovina to submit official bids to the international tender of the FBiH Ministry of Energy and Mining. The tender was announced on January 7th 2020.

Table 5.34 **Bosnia and Herzegovina, Annual balance of natural gas** [8]

1000 Sm3	2016	2017	2018
Available for Supply	226.927	245.415	244.578
Production			
Import	226.927	245.415	247.012
Export			2.408
Stock exchange			-26

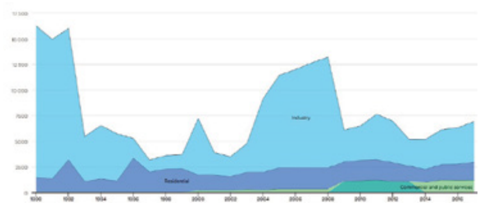
Source: Energy statistics: Natural gas, Agency for Statistics of Bosnia and Herzegovina

Table 5.35 **Consumption of natural gas by categories in Bosnia and Herzegovina** [13]

1000 Sm3	2016	2017	2018
Consumption in energy sector	59.362	61.747	61.672
Total losses	626	542	966
Final consumption	166.939	183.126	181.940
Industry	93.344	105.198	106.984
Transport	110	1.336	2.505
Households	42.438	46.418	44.216
Other	31.047	30.174	28.235

Source: Energy statistics: Natural gas, Agency for Statistics of Bosnia and Herzegovina, 2017, 2018, 2019

Figure 5.43 **Consumption of natural gas in Bosnia and Herzegovina by sector (TJ)**



Source:International Energy Agency, www.iea.org

(b) Natural gas Import and Dependence

The total imports of natural gas to Bosnia and Herzegovina for 2018 reached 247.012.000 Sm^3. All imported and exported quantities of natural gas are presented in Table 5.35. Practically Bosnia and Herzegovina imports the entire quantity of natural gas it uses and is 100% dependent on imports in order to meet its needs (~0,25 billion m^3/year). The country is 100% dependent on a single source and on one natural gas pipeline. Most of the gas imports for the wider region are supplied from Russian sources. Russian gas is delivered via Ukraine, and then via transit routes through Hungary and Slovakia. It is evident that the region is traditionally highly dependent on one source of gas. Having in mind that Bosnia and Herzegovina does not have its own gas resources and storage facilities, the country covers 100% of its needs through gas imports from Russia.

(c) Infrastructure (Pipelines, Storage) (current and planned)

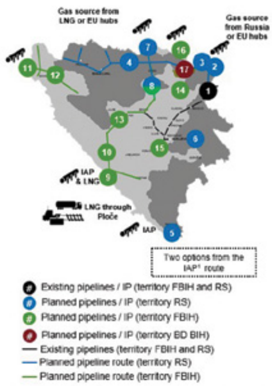
There is only one gas interconnection between BiH with neighboring countries. This is the interconnection between BiH and Serbia. The internal existing gas transmission pipeline connects the interconnection point (BiH/ Serbia) with the cities of Sarajevo, Visoko and Zenica (Map 5.5). This single cross-border point and only one pipeline does not allow any possibility for diversified gas supplies to the country nor the provision of a minimum level of security of supply and hence is unable to attract potential new customers.

Consequently, pipeline development plans for Bosnia and Herzegovina must follow planned cross-border projects relevant to Bosnia and Herzegovina and in line with South East Europe's pipelines network. Complex political relationships within the country additionally complicate the already "difficult" situation with gas. The goal for both entities is to increase the importance of natural gas as an energy source in the economy with the aim of strengthening the integration of gas market and security of supply, but approaches are not the same.

The strategic vision of the Federation of Bosnia and Herzegovina is a systematic vertical linkage to the Croatian gas pipeline system (gas ring formation and gas supply from multiple sources: LNG, IAP or in general EU gas hubs). The goal for the Republic of Srpska is a new interconnection with Serbia in the Bijeljina area and construction of the Bijeljina - Banja Luka pipeline. Map 5.5 presents the actual situation with the pipelines (only one interconnection to Bosnia and Herzegovina-Serbia and one internal pipeline) and the plan for new pipelines.

[8] Energy statistics: Natural gas, Agency for Statistics of Bosnia and Herzegovina, 2017, 2018, 2019

Map 5.5 **Actual status and plan for gas pipeline in Bosnia and Herzegovina**



	Project name	Direction		Techn. capacity (bcm/year)	
		From	To	Import	Export
1	Interconnection Zvornik	SRB	BIH	0,8	-
2	Šepak - Bijeljina	Šepak	Bijeljina	1,5	-
3	Interconnection with Serbia in Bijeljina (Novo Selo) area	SRB	BIH	2,0	-
4	Gas pipeline (Bijeljina – Banja Luka and further)	SRB	BIH	2,0	-
5	Gasification of Trebinja from IAP	IAP	BIH	n/a	n/a
6	Gasification of Gornjeg Podrinja	Gasification from an existing system		n/a	n/a
7	Slobodnica – Brod, northern interconnection BIH & CRO on CRO territory (TRA-N-066)	CRO	BIH	5,6	5,6
8	Brod - Zenica, northern interconnection BIH & CRO on BIH territory (TRA-N-224)	Brod	Zenica	1,2	1,2
9	Zagvozd – Imotski – Posušje, Southern interconnection BIH & CRO on CRO territory (TRA-N-302)	CRO	BIH	2,8	2,8
10	Posušje – Novi Travnik / Travnik with a Mostar section, Southern interconnection BIH & CRO on BIH territory (TRA-N-851)	Posušje	Travnik	1,3	-
11	Rakovica –Tržac, Western interconnection BIH & CRO on CRO territory (TRA-N-910)	CRO	BIH	0,9	-
	Tržac – B. Krupa with sections for Bihać and Velika Kladuša, Western interconnection BIH & CRO on BIH territory (I. phase)	Tržac	B. Krupa & sections	0,9	-
12	Western interconnection BIH / CRO with gas pipelines B. Krupa – Ključ (II phase) & Pećigrad – Bužim (III phase)	B. Krupa	Ključ	n/a	n/a
		Pećigrad	Bužim	n/a	n/a
13	Travnik - G. Vakuf & Travnik – Jajce	Expansion of existing infrastructure		n/a	n/a
14	Underground gas storage near salt caverns in Tetima	+ pipeline Kladanj-Tuzla-Tetima		Min. capacity 60mcm	
15	Gasification of Gornje Podrinje	Gasification from an existing system		n/a	n/a
16	Gasification of Orašje	CRO	BIH	n/a	n/a
17	Gasification of Brčko District of Bosnia and Herzegovina	Connection in line with entity plans			

Source: "Framework Energy Strategy of Bosnia and Herzegovina until 2035"

(d) Domestic Gas Market

Legislation regulating the gas sector exists only at the entities level but not at the level of Bosnia and Herzegovina. This issue for some time has been the subject of discussions between the stakeholders in Bosnia and Herzegovina. The Energy Community introduced "measures" against Bosnia and Herzegovina related to non-implementation of obligations (gas legislation on the state level) in accordance with the Third Energy Package (Energy Community Treaty). During the last year(s) the situation with further market development is unclear and unfavorable for potential investors. The actual gas market is characterized by a lack of competition and the absence of entry of new players. Furthermore, existing gas customers are not able to switch their gas supplier and gas prices are regulated.

Solid Fuels

(a)Supply and consumption

In Bosnia and Herzegovina, coal (brown coal and lignite) is the dominant energy source, accounting for 67.66% of the country's TPES in 2013 and for 58% of its electricity generation, consumed mainly by power plants near to mines. Production of brown coal and lignite in Bosnia and Herzegovina was 7,0 and 7,5 million tons respectively in 2018.

This production was 2,9% higher than previous year's production. Final consumption of brown coal and lignite was 0,42 and 0,30 million tons respectively in the same year. Consumption in energy sector of brown coal and lignite was 6,4 and 7,0 million tons respectively. Detailed data about the annual balance of coal in Bosnia and Herzegovina is shown in Table 5.36.

Table 5.36 **Annual balance of Coal and Coke-oven Coke in Bosnia and Herzegovina** [9]

	2017				2018			
t	*Hard Coal*	*Lignite*	*Brown Coal*	*Coke Oven Coke*	*Hard Coal*	*Lignite*	*Brown Coal*	*Coke Oven Coke*
Available for Supply	1.270.168	7.766.710	6.363.049	391.317	1.456.634	7.350.811	6.803.267	429.025
Production	*0*	*7.698.496*	*6.385.213*	*855.036*	*0*	*7.499.872*	*7.005.011*	*944.568*
Import	*1.361.422*	*24.921*	*73.568*	*57.916*	*1.457.143*	*83.689*	*22.409*	*38.397*
Export		*11.112*	*227.506*	*305.686*	*7*	*6.976*	*188.350*	*565.767*
Stock exchange	*-91.254*	*54.405*	*131.774*	*-215.949*	*-502*	*-225.774*	*-35.803*	*11.827*
Total Losses	0	22	17.656	0	0	0	0	0
Consumption in energy sector	1.182.075	7.472.473	5.847.077	390.218	1.318.991	7.048.051	6.379.766	428.875
Final consumption	88.093	294.215	498.316	1.099	137.643	302.760	423.501	150
Industry	*88.093*	*35.922*	*172.820*	*1.099*	*137.643*	*28.805*	*196.659*	*150*
Construction		*43*				*260*		
Transport								
Agriculture		*736*				*696*		
Households		*221.119*	*186.368*			*226.838*	*77.143*	
Other		*36.395*	*139.128*			*46.161*	*149.699*	

Source: Energy statistics: Coal, Agency for Statistics of Bosnia and Herzegovina

[9] Energy statistics: Coal, Agency for Statistics of Bosnia and Herzegovina, 2018, 2019

(b) Local production and exploration

The coal sector is an important segment of the energy sector and an integral part of the economic structure of Bosnia and Herzegovina. Out of the total energy potential of the country, coal covers more than 90% and is rightly considered as the the dominant energy source. About 14 major mines are currently active in Bosnia and Herzegovina. The locations of key coal deposits are presented in Map 5.6. Mines, coal types and methods of extraction are given in Table 5.37.

Map 5.6 **Key coal mines in Bosnia and Herzegovina**

Table 5.37 **List of coal mines**

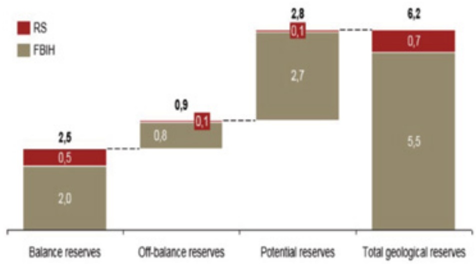
Mine	Coal type	Method of extraction
Rudnici Kreka d.o.o.	Lignite	Surface and underground
RMU Abid Lolić d.o.o.	Hard coal	Underground
RMU Breza d.o.o.	Hard coal	Surface and underground
RMU Đurđevik d.o.o.	Hard coal	Surface and underground
RMU Kakanj d.o.o.	Hard coal	Surface and underground
RMU Zenica d.o.o.	Hard coal	Underground
Rudnik Gračanica d.o.o.	Lignite	Surface
RMU Banovići d.o.o.	Hard coal	Surface and underground
RU Tušnica d.o.o.[22]	Lignite/hard coal	Surface
ZP RiTE Ugljevik (Bogutovo selo and Ugljevik Istok 1)	Hard coal	Surface
ZP RiTE Gacko	Lignite	Surface
Rudnik Stanari	Lignite	Surface
New hard coal mine Miljevina	Hard coal	Surface and underground
Other[1]	Dominantly hard coal	Surface

Source: Framework Energy Strategy of Bosnia and Herzegovina until 2035, 2018

(c) Deposits

According to the Framework Strategy, Bosnia and Herzegovina had (2010) 2.631 million tons of balance reserves, 604 million tons of off-balance reserves and 2.511 million tons of potential reserves. Total geological reserves amounted to 5.594 million tons of coal. The share of lignite in the balance reserve was 55% and hard coal share was 45% of the total balance reserve of coal. The structure of coal reserves is presented in Figure 5.44.

Figure 5.44 **Structure of reserves of mines in Bosnia and Herzegovina (billion t)**



Source:Framework Energy Strategy of Bosnia and Herzegovina until 2035, 2018

(d) Planned new projects

The coal industry in Bosnia and Herzegovina, as well as globally, is facing significant challenges. Historical reasons (poor geological conditions, lack of maintenance and investment, significant labor cost) on the one hand, and the demands of the new "non carbon" era (CO_2 tax, lower demand) on the other hand put a significant strain on the coal mining industry. The government(s) plans to restructure the industry (merging coal mines and power plants, close too expensive mines, investment) and in this way save jobs. Additionally, the government(s) "push" for new thermal power plants has resulted in many new projects in the horizon. The new coal mines projects are closely connected with new thermal power plants projects.

The Framework Energy Strategy of Bosnia and Herzegovina until 2035 analyzed several different scenarios for the new power plants. Selection of one of the scenarios (power generation mix until 2035) is a discretionary decision of stakeholders at entity and State level in accordance with legal and regulatory obligations. It should be noted that a significant number of new thermal power plants are currently planned within the context of the Framework Strategy, but it is questionable how compatible they are with EU's energy policy.

According to the "most relevant" scenario ("entity scenario") the installed capacity in thermal power plants by 2035 will increase by 189% (compared to 2016). That means that 2.600MW in new thermal power plant capacity is planned, but meanwhile six (6) thermal power plant units are going to be decommissioned with total capacity of 926 MW. The time ahead will indicate whether the planned new "coal MWs" are realistic or over-optimistic. Figure 5.45 shows the anticipated changes (new power plants, decommissioning of existing power plants) in installed capacity in Bosnia and Herzegovina from 2016 till 2035.

Electricity

(a)Electricity supply and demand

A record in electricity generation amounting to 17.873 GWh was reached in the 2018, which was18.0% more than that generated in 2017. The production in 2018 was the result of the very favorable hydrological conditions during the year (65% higher production of HPP compared to 2017).

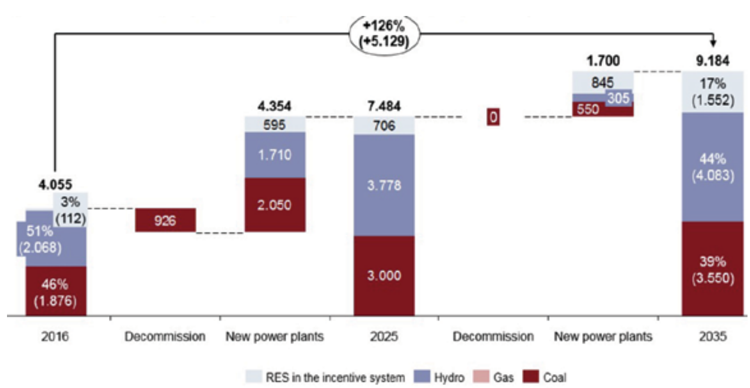
Total electricity consumption amounted to 13.294 GWh (2018) or 3,3% more than in 2016, but total electricity consumption in 2019 amounted to 12.330 GWh or 7,3% less than the previous year. This significant decline in electricity consumption was the result of the termination of operation of Aluminijum[10], the largest electricity consumer in Bosnia and Herzegovina (about 2.000 GWh/year).

(b) Installed Capacity

The total installed capacity of power generation units in Bosnia and Herzegovina in 2019 amounted to 4.508 MW, with 2.077 MW (46,1%) and 2.065 MW (45,8%) installed corresponding to large hydro power plants and thermal power plants respectively. During the period 2016-2019 there were some changes in the structure of installed capacity:

- TPP Stanari 300 MW (IPP[11]) started commercial operation (2016)
- Two wind farms (WPP Mesihovina (51MW) and WPP Jelovača (36MW)) also started commercial operation in 2018.

Figure 5.45 **BiH installed capacity by technology in MW, 2016 - 2035**



Source:Framework Energy Strategy of Bosnia and Herzegovina until 2035, 2018

[10] The termination of operation was due to business reasons (financial indicators, significant debts) with a very unfavorable chance of resuming aluminum production in the medium term.
[11] EFT Group is owner of TPP Stanari

Table 5.38 **Total installed capacity in Bosnia and Herzegovina (2019)**[12]

	2019 - Installed Capacity (MW)	% of Total
Thermal Power Plants	2.065	45,8%
Hydro Power Plants	2.077	46,1%
Wind Power Plants	87	2,0%
Small Hydro Power Plants	162	3,6%
Solar Power Plant	22	0,5%
Biogas & Biomass PP	3	
Industrial Power Plant	91	2,0%
TOTAL	4.508	

Source: Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

Table 5.39 **Balance of electric power system of Bosnia and Herzegovina**

GWh	2015	2016	2017	2018	2019
Electricity generation	14.407,9	16.508,9	15.151,4	17.873,0	16.074,0
Net imports	3.965,4	3.144,6	3.428,2	3.118,7	2.825,0
Net exports	5.767,6	6.788,4	5.213,2	7.697,8	6.568,8
Gross electricity consumption	12.605,7	12.865,1	13.366,4	13.294,0	12.330,1
Transmission losses	359,4	333,3	341,5	398,8	324,0
Distribution losses	1.035,1	1.024,8	1.005,9	950,0	933,3
PPs self-consumption and pumping	27,9	75,1	284,0	152,7	113,1
Final consumption of electricity	11.183,3	11.431,9	11.735,0	11.792,5	10.959,8
Non-households	6.456,9	6.698,9	6.978,9	7.107,2	6.233,9
Households	4.726,5	4.733,0	4.756,1	4.685,3	4.725,9

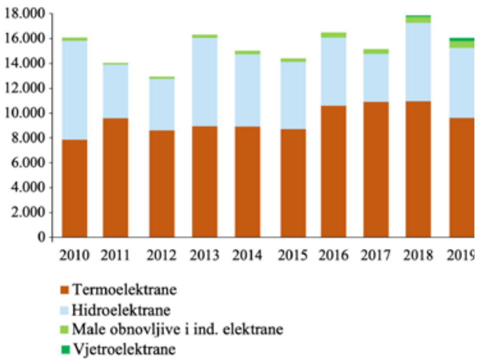
Source: Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

Table 5.40 **Generation and consumptions by categories**

GWh	2016	2017	2018	2019
Electricity Generation in hydro power plants	5.469,4	3.831,4	6.300,1	5.649,6
Generation in thermal power plants	10.607,9	10.918,4	10.953,8	9.613,0
Generation in larger wind plants	0,0	0,0	103,5	253,7
Generation in small and industrial PPs	431,6	401,6	515,7	557,8
Generation	**16.508,9**	**15.151,4**	**17.873,0**	**16.074,0**
Distribution consumption	9.987,7	10.179,1	10.138,7	10.142,6
Transmission losses	333,3	341,5	398,8	324,0
Large customers	2.468,9	2.561,8	2.603,8	1.750,6
PPs self-consumption and pumping	75,1	284,0	152,7	113,1
Consumption	**12.865,1**	**13.366,4**	**13.294,0**	**12.330,1**

Source: Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

Figure 5.46 **Electricity generation by categories in Bosnia and Herzegovina in last ten years (GWh)**



Source: Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

[12] Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

(c) Electricity imports - exports

Looking at the balance of the electricity power system of Bosnia and Herzegovina during 2015-2019 (Table 5.39) it is evident that the country has been generating a surplus of electricity. Also, it is evident that, in average, this surplus is the result of the high share of coal in the electricity generation mix. Yearly variation of the above-mentioned electricity surplus is due to the impact of hydrological conditions ("dry" or "wet" year). The net export of electricity from Bosnia and Herzegovina in 2018 amounted to 4.579 GWh and represents an increase of 157% compared to the previous year. This difference is due to two hydrologically very different years.

(d) Electricity Prices

Since 1 January 2015, all customers in BIH have the possibility of choosing freely their suppliers. Customers that do not choose their supplier may be supplied by public suppliers (the role of the Reserve supplier) at public supply prices, while households and small customers may be supplied within the universal service at regulated prices. Network activities are fully regulated by regulatory commissions dependent on their jurisdictions:

- SERC regulates the whole transmission level (Tariff for ISO Operation, Tariff for the Services of Elektroprijenos BiH, Tariffs for Ancillary and System Services)
- Entity regulators regulate the distribution level (distribution network tariffs)

Electricity customers from the household category and other categories (voltage level of 0,4kV-small companies and commercial customers) who have not chosen their electricity supplier have the right for the supply of standard quality electricity, at economic transparent prices, within the scope of universal services offered from a public supplier. There is also the Reserve supplier, who has the obligation to supply the eligible electricity customer in periods no longer than 60 days, when the chosen supplier terminates /stops to supply the eligible customer. Public and Reserve suppliers of electricity in Federation BiH are appointed by the government of Federation BiH (public utilities (incumbents): Elektroprivreda BiH and Elektroprivreda HZHB).

Additional to price regulation for customers under universal service in RS there is some kind of generation regulation where RERS (the Entity Regulator) regulates the production of electricity. In this way, they maintain the price level of electricity for all customers in the RS independent of the market price.

Table 5.41 presents the average prices of electricity for end customers in Bosnia and Herzegovina by customer category. Prices are without VAT and renewables fee. It can be observed that for most of the customer categories there has been a price increase. The prices in 2019 increased from 8% to 20% compared to 2017. The exception is household tariffs where the price has not changed.

Table 5.41 **Average prices of electricity by customer category without VAT (EUR/MWh)**

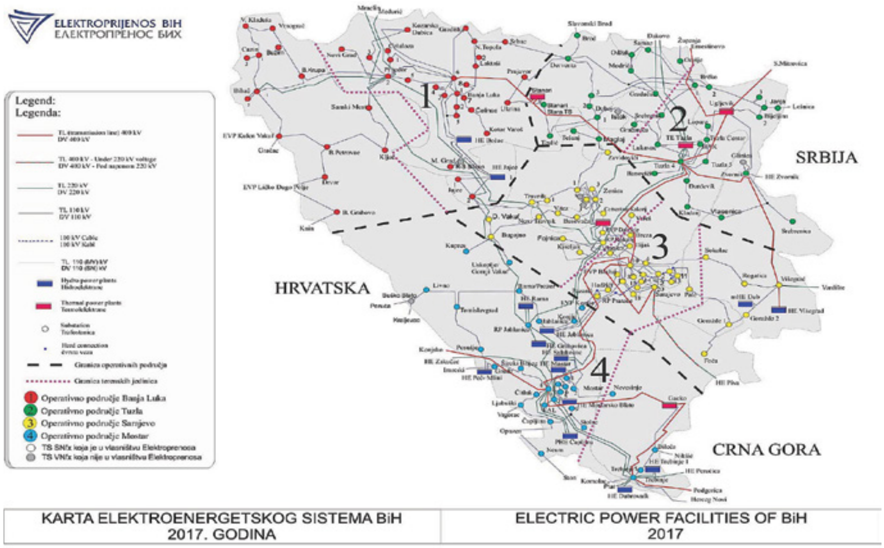
Category of customer	2017	2018	2019	2019/ 2017
110kV	42,44	48,57	50,77	120%
35kV	50,06	53,23	57,21	114%
10kV	59,00	9,92	63,91	108%
0,4kV Commercial	90,24	90,45	91,52	101%
Households	72,19	72,60	72,50	100%
Public Lighting	81,96	85,95	88,30	108%

Source: Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

(e) Cross-border interconnections

Elektroprijenos BiH is the owner of transmission network and the Independent System Operator of Bosnia and Herzegovina (ISO BiH) and is responsible for the operation of the transmission system of Bosnia and Herzegovina. Transmission network consists of over 6,400 km of overhead lines (400kV, 220 kV and 110 kV), 153 transformer stations and switchgears at 400, 220 and 110kV voltage levels with 12.783 MVA total installed capacity.

Map 5.7 **Map of electric power facilities of Bosnia and Herzegovina** [13]



Source: Elektroprijenos of Bosnia and Herzegovina, https://www.elprenos.ba/EN/MapeEN.aspx

(f) Planned new projects

The Framework Energy Strategy of Bosnia and Herzegovina until 2035 analyzed several different scenarios for new power plants. Selection of one of the scenarios, or power generation mix until 2035, is a discretionary decision of stakeholders of entities and the State in accordance with legal and regulatory obligations. According to the "most relevant" scenario ("entity scenario") the installed capacity will increase by 126% by 2035 (compared to 2016), i.e. 5.129 MW, including commissions and decommissions. It is planned that most of the new planned facilities (with a total capacity of 4,354 MW) will be put into operation by 2025. In the same period, six thermal power plants will be decommissioned with a total capacity of 926 MW. During the period of 2025 - 2035, another 1.700 MW of capacity will be commissioned, with no additional decommissions.

Figure 5.45 shows the changes (new power plants, decommissions of existing power plants) in installed capacity in Bosnia and Herzegovina from 2016 till 2035. Additionally, Tables 5.43 and 5.44 show a list of potentially new thermal and RES (including hydro) projects in Bosnia and Herzegovina, respectively, sorted by type.

During the previous years, and for various reasons, a significant number of new thermal power plants were planned in Bosnia and Herzegovina. From today's perspective, some of the planned power plants are not realistic, in view of increased competition, environmental constraints and the emphasis on RES following the EU Green Deal approach. Some of the plants did not follow the necessary procedures that precede the planning documents (studies, permits, financing issues). Due to all of the above, certain TPPs are still marked as "under preparation" or "under consideration" status.

According to the Indicative Generation Development Plan for 2020 - 2029 of the Independent System Operator of Bosnia and Herzegovina, new planned capacities for the period 2020-2029 are presented in Table 5.42.

Table 5.42 **New planned capacities in the period 2020-2029**[14]

Type	Facility	Installed capacity (MW)	Indicative start date of operation
Hydro	HPP Ulog	35	2021
Hydro	HPP Dabar	159	2024
Hydro	HPP Vranduk	20	2023
Hydro	HPP Ljuta	8	2021

[13] Elektroprijenos of Bosnia and Herzegovina, https://www.elprenos.ba/EN/MapeEN.aspx

Hydro	HPP Janjići	17	2024
Coal	TPP Tuzla 7	450	2023
Coal	TPP Kakanj 8	300	2025
Gas	KTG Zenica	387	2029
Wind	WPP Trusina	50	2021
Wind	WPP Podveležje	48	2021

Source: Indicative Generation Development Plan for the period from 2020. to 2029., Jun 2019, Independent system Operator of Bosnia and Herzegovina

Table 5.43 **List of potential new Thermal projects in Bosnia and Herzegovina***

Type	Facility	Installed capacity (MW)	Indicative year of commission
Coal	TPP Tuzla 7	450	2020-2035
Coal	TPP Kakanj 8	350	2024-2028
Coal	TPP Banovići	350	2020-2030
Coal	TPP Kongora	2x275	2025-2035
Coal	TPP Ugljevik 3	600	2019-2025
Coal	TPP Gacko 2	350	2024-2025
Gas	CTPP Zenica	385	2020-2035
Biomass	CHP plant	110	2022-2024

* Based on a list from "the Framework Energy Strategy of Bosnia and Herzegovina until 2035"

Table 5.44 **List of potential new RES projects in Bosnia and Herzegovina***

Type	Facility	Installed capacity (MW)	Indicative year of commission
Hydro	HPP Vranduk	20	2019-2023
Hydro	HPP Ustikolina	59	2022-2030
Hydro	HPP Glavatićevo	28	2030-2034
Hydro	HPP Han Skela	12	2022-2028
Hydro	HPP Vrletna Kosa	11,2	2022-2028
Hydro	HPP Bjelimići	100	2023-2035
Hydro	HPP Janjići	13	2021-2028
Hydro	HPP Kovanići	10	2025-2028
Hydro	HPP Babino Selo	5	2023-2026
Hydro	HPP Neretvica I	9	2017-2019
Hydro	HPP Neretvica II	15	2023-2025
Hydro	HPP Una Kostela	6	2018-2020
Hydro	PSHPP Vrilo	66	2020-2023
Hydro	PSHPP Kablić	52	2020-2027
Hydro	HPP Ugar	11,6	2020-2023
Hydro	HPP Ivik	11,1	2020-2026
Hydro	Small HPPs on Cetina	13,1	2024-2035
Hydro	HPP Dabar	159,15	2020-2022
Hydro	HPP Nevesinje	60	2023-2028
Hydro	HPP BukBijela	93,52	2022-2024
Hydro	RHPP BukBijela	600	2022-2030
Hydro	HPP Foča	44,15	2024-2028
Hydro	HPP Dubrovnik2	152	2021-2030
Hydro	HPP Sutjeska	44,08	2024-2028
Hydro	HPP Paunci	43,21	2024-2028
Hydro	HPP Rogačica	56,64	2025-2030
Hydro	HPP Tegare	60,47	2025-2028
Hydro	HPP Doboj	8,39	2021-2028
Hydro	HPP Bileća	33	2021-2028
Hydro	HPP Cijevna 1	14,1	2021-2028
Hydro	HPP Cijevna 2	14,2	2021-2028
Hydro	HPP Cijevna 3	13,9	2021-2028
Hydro	HPP Cijevna 4	13,9	2021-2028
Hydro	HPP Cijevna 5	13,2	2021-2028
Hydro	HPP Cijevna 6	12,9	2021-2028
Hydro	HPP Ulog	35	2017-2020
Hydro	HPP Mrsovo	43	2017-2020
Hydro	HPP Cehotina	18	2021-2028
Hydro	HPP Kozluk	44,25	2025-2035
Hydro	HPP Drina I	43,85	2025-2035
Hydro	HPP Drina II	43,90	2025-2035
Hydro	HPP Drina III	50,5	2025-2035
Hydro	HPP Dubravica	43,61	2025-2035
Hydro	HPP Trn	21,42	2025-2035
Hydro	HPP Laktaši	21,42	2025-2035
Hydro	HPP Kosjerevo	21,42	2025-2035
Hydro	HPP Razboj	21,42	2025-2035
Hydro	HPP Dub	9	2018-2018
Hydro	HPP Bočac II	8,76	n/a
Hydro	HPP Novoselija	16,4	n/a
Wind	WPP Mesihovina	50,6	2017-2018
Wind	WPP Poklečani	72	2020-2025
Wind	WPP Velika Vlajna	32	2023-2028
Wind	WPP Borova Glava	52	2026-2030
Wind	WPP Podveležje	48	2018-2019
Wind	WPP Vlašić	48	2021-2025
Wind	WPP Bitovinja	54	2027-2035
Wind	WPP Zukića Kosa	15	2028-2035
Wind	WPP Medveđak	40	2031-2035+
Wind	WPP Rostovo	20	2033-2035+
Wind	WPP Borisavac	48	2035-2035
Wind	WPP Trusina	51	2018-2020
Wind	WPP Hrgud	48	2019-2021
Wind	WPP Grebak	48	2031-2035

* Based on a list from "the Framework Energy Strategy of Bosnia and Herzegovina until 2035"

[14] Indicative Generation Development Plan for the period from 2020. to 2029., Jun 2019, Independent system Operator of Bosnia and Herzegovina

Renewables

(a) Overview of sector's development (legislation, policies)

RES policy is in line with the administrative organization of Bosnia and Herzegovina. The general framework for a promotion of RES generated electricity is defined by Law on Usage of Renewable Energy Sources and Efficient Cogeneration (FBiH entity) and the Law on Renewable Sources of Energy and Efficient Cogeneration (RS entity). In this sense, the promotion system is administered by the RES Operators (in both entities).

In the Federation BiH (entity) the promotion system is administered by the RES Operators. The FBiH Government passed a Decision on Establishment of RES Operator, according to which the RES Operator in FBiH established. The FBiH RES Operator, inter alia, conducts the following activities: (i) concludes contracts on purchases of electricity at guaranteed prices and buys the total electricity produced from privileged producers; (ii) maintains the Register of guarantees and the Register of projects; and (iii) conducts the procedure for actually granting the status of a privileged producer to a potentially privileged producer. The promotion scheme generally depends on the classification of the producer of RES-Electricity (installed capacity and type of producers). All producers of RES Electricity have advantages concerning connection to the grid. "Privileged producers" have the right to sell all produced electricity under the feed-in tariff ("the Guaranteed price") for a determined period of time (12 years). A "Qualified producers" (producers have not obtained the status of the privileged producer or whose status of the privileged producer has expired) have the right to sell all produced electricity at the Reference price (The price is defined by the Regulator).

The status of a potential privileged producer can only be obtained if the required installed capacity of renewable energy generation within the allocated quota is available for a particular type of technology. The quota is the maximum level of installed capacity of the RES privileged producers whose production is subsidizes, and for each primary source of energy is determined by the Action Plan for Renewable Energy Sources of the Federation of BiH (APOEF).
The Law foresees that the quotas be allocated in the order of the entry of projects into the Project Register.

In Republic of Srpska (entity), the role of RES Operator is performed by the Public Utility Elektroprivreda RS. The promotion system includes: (i) benefits for the grid connection and access; (ii) mandatory repurchase of electricity; (iii) feed-in tariff; and (iv) premiums. In more detail, this includes:

- benefits when connecting to the grid, in terms of time and in certain cases the costs for analysis of connection to the grid;
- preferential access to the network (dispatching) provided by the system operator (limitation is made only for those producers of electricity which sell the electricity on the market);
- right to the repurchase of electricity for a determined period (15 years);
- feed-in tariffs;
- premiums for consumption of electricity for personal use or sale in the market.

In order to take advantage of the incentives, the RES producer in RS must obtain an RES certificate and a Decision on the right to an incentive. For the Decision it is necessary to submit an application to the Regulatory Authority. Subsequently, the Incentive System Operator (public utility) establishes a contract for the purchase of electricity by feed-in tariff, which varies depending on the size and technology of the plant or the premium. The Renewable Energy Action Plan of Republic of Srpska (RS Action Plan), adopted by the Entity Government, defines quotas for privileged producers, as well as tariffs. Feed-in tariffs and premiums are awarded according to the order of submission of the application to RERS, until the complete quotas set in the Action Plan are exhausted. It should be noted that the incentive is not granted to producers who embed used equipment in the plant. The main components for the production of electricity (generators, photovoltaic panels, boilers or turbines) must be new to be eligible for incentive.

(b) Feed-in tariffs

There are methodologies for the calculation of feed-in tariffs as well as criteria for anticipated changes. The respective rulebook is approved following consultation with the expert community and other relevant stakeholders, and takes into consideration criteria such as form of primary energy, the technology which is being used, installed power of the facility, starting date of operation of the facility, as well as the contracted term of repurchase.

In Federation BiH (entity) the feed-in tariffs consist of a tariff coefficient and a reference price. Accordingly, the Reference price as of 1 March 2019 was 55,64 EUR/MWh and is determined based on the previous twelve (12) month period by the Entity regulatory authority (FERK). The tariff coefficient is determined depending upon the type and size of the facility. The tariff coefficient used for the calculation of feed-in tariffs is adopted every eighteen (18) months. In Table 5.45 actual feed-in tariffs are presented (valid from March 2019).

Table 5.45 **Feed-in-Tarrifs for different RES installations (FBiH)**

Type of plant according to type of primary energy source	Capacity kW	Guaranteed price (FIT) from March 2019 EUR/MWh
Hydro Power Plant	**up to kW**	
a) micro	23	144,36
b) mini	150	88,91
c) small	1.000	66,68
d) middle	10.000	59,87
Wind Power Plant		
a) micro	23	186,86
b) mini	150	110,25
c) small	1.000	94,02
d) middle	10.000	79,61
Solar Power Plant		
a) micro	23	208,15
b) mini	150	115,88
c) small	1.000	93,12
Biomass Power Plant		
a) micro	23	154,82
b) mini	150	122,73
c) small	1.000	118,18
d) middle	10.000	111,22

Source: Calculation based on the Decision of the Government of FBiH from February 2019

In RS (entity) the feed-in tariffs are determined on the basis of a methodology prepared by the RERS (Entity regulatory authority). The feed-in tariffs consists of "a reference price" for mandatory sale of all produced electricity and a "premium". The values of feed-in tariffs are determined by the RERS with the approval of the RS Government. The RERS determines the amount of feed-in tariffs at least once a year and makes adjustments for the upcoming period if and where necessary. In Table 5.46 the actual calculated feed-in tariffs and premium values for 2019 are presented.

Table 5.46 **Feed-in-Tarrifs and premium values for 2019 (RS)**

Type of plant according to type of primary energy source	Premium EUR/MWh	Feed-in Tariff EUR/MWh
Hydro Power Plant	**up to kW**	
(a) up to 1MW	42,23	71,38
(b) from 1MW to 5MW	33,59	62,74
(c) from 5MW to 10MW	31,50	60,64
Wind Power Plant		
(a) up to 10MW	45,81	74,96
Solar Power Plant		
(a) up to 50kW (on the roof)	110,64	139,79
(b) from 50kW to 250kW (on the roof)	90,55	119,69
(c) from 250kW to 1MW (on the roof)	65,75	94,9
Solar (on land) up to 250kW	81,76	110,9
Biomass Power Plant		
(a) up to 1MW	94,23	123,37
(b) from 1MW to 10MW	86,46	115,6

Source: Calculation based on the Decision of the Regulatory Commission for Energy of Republic of Srpska from July 2018

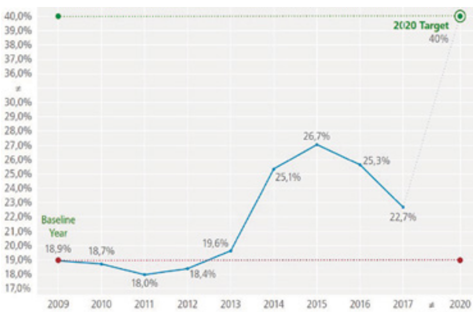
(c) Installed capacity per source

"In 2017, Bosnia and Herzegovina achieved a 22,7% share of renewable energy in gross final energy consumption (Figure 5.47), way below the 37,9% median trajectory for 2017 - 2018. This is due to the downward revision of biomass consumption and limited investments in new renewable energy capacities." [15]

[15] Annual Implementation Report 2018/2019, Energy Community Secretariat, November 2019

Despite the significant delay in the implementation of defined targets, there is no significant official activity for a new approach in the foreseeable future. This has been addressed in the EnCS's Implementation Report 2018/2019. Activities towards the adoption of revised renewable energy laws that include a market - based approach for granting support, in line with Guidelines on State aid for environmental protection and energy 2014 - 2020, have not yet commenced in any entity.

Figure 5.47 **Shares of energy from RES**



Source: Annual Implementation Report 2018/2019, Energy Community Secretariat, November 2019

Table 5.47 **RES installed capacity per source**

MW	2018	2019
Wind Power Plant	51,4	87,0
Solar PV Plant	18,2	22,4
Hydro Power Plant	2.235,6	2.238,8
Small Hydro Power Plant	159,0	162,2
Large hydro with reservoir or run-of-river Power Plant	2.076,6	2.076,6
Biomass & Biogas Power Plant	1,2	3,3
Total Installed Capacity	**2.306,4**	**2.351,5**

Source: Based on data from Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

(d) Planned new RES plants

Table 5.48 lists potential new RES generation projects (including hydro) in Bosnia and Herzegovina. From the listed projects the wind farms Podvelezje (48MW) is at an advanced stage of construction and WPP will be connected to the network by the end of Q2 of 2021. For other larger projects, there is still no reliable information on the status of realization.

Energy Efficiency and Cogeneration

(a) National targets

The main driver for the promotion of energy efficiency in BiH are the commitments under the Energy Community Treaty. Energy prices, especially for electricity and heating, are still relatively low compared to other European countries and do not provide strong incentives to save energy. In recent years, a number of public buildings have been renovated, but much work remains to be done in this field. Most existing buildings are in poor condition with high energy requirements. Although the implementation of energy efficiency measures has started with promising results, lack of funding remains a major bottleneck for the development of this sector.

According to the Energy Community Treaty commitments Bosnia and Herzegovina is required to transpose EU directives[16] into its energy efficiency legislation. Bosnia and Herzegovina legal framework for energy efficiency has been improved over the years, but is not yet at the required level. In the coming period, it is necessary to take a series of decisions and measures that not only transpose binding EU directives according to the obligations of the Energy Community Treaty, but would also fully enable their implementation.

The state-level National Energy Efficiency Action Plan (NEEAP), adopted by the Council of Ministers (State Government) in December 2017, includes forecasted energy savings and targets for primary and final energy consumption for Bosnia and Herzegovina, Federation Bosnia and Herzegovina, Republic of Srpska and Brčko District for 2020.

[16] Directive 2006/32/EU on energy end-use efficiency and energy services, Directive 2010/31/EU on the energy performance of buildings, Directive 2010/30/EU on the indication by labelling and standard product information of the consumption of energy and other resources by energy-related products, Directive 2012/27/EU on energy efficiency, which obliges contracting parties to much more stringent requirements that must be met in the field of energy efficiency

According to the NEEAP, the indicative target for savings in primary energy consumption in Bosnia and Herzegovina in 2020 is defined as follows: "By the end of 2020, primary energy consumption will be reduced by 12% compared to forecasted consumption without energy efficiency measures. In absolute terms, and in comparison, to the forecasted primary energy consumption of 8,031.98 ktoe without any energy efficiency measures, this amounts to 7,068.14 ktoe with implementation of planned energy efficiency measures or a reduction of consumption by 963.84 ktoe." [17]

The specific targets under the Energy Efficiency Directive are still not set (for renovation of central government buildings and the energy efficiency obligating scheme), but most of the activities have been finalized and are awaiting political decisions. The final energy efficiency obligation scheme model for Bosnia and Herzegovina was prepared and presented to stakeholders. In order to put this mechanism in place, Bosnia and Herzegovina should pass the necessary amendments to the entity Energy Efficiency Laws, formulate the calculation of methodologies and issue a regulation on the implementation of the scheme via implementing regulations or guidelines.[18]

(b) EU funded (or otherwise funded) energy efficiency programmes in the building sector

According to Energy Community Secretariat, the energy efficiency investment needs in the Western Balkans' buildings sector alone are probably in excess of €3 billion[19,20]. Most facilities rely on local financial intermediaries to identify and implement projects using funds provided by the facilities. Approximately 45 commercial banks or financial institutions offer energy efficiency or renewable energy financial products in the region. Many of their financial products are based on the offer of dedicated credit lines made available by international financial institutions and development banks, supported by EU grant funding for both technical assistance and financial incentives.[23]

Some of the them are listed below:

- Regional Energy Efficiency Programme (REEP and REEP Plus). Technical assistance and investment grants (EBRD, EU) [21]
- Green Economy Financing Facility (GEFF). Technical assistance and investment grants (EBRD) [22]
- Green for Growth Fund (GGF). Technical assistance and investment grants (EIB, KfW) [23]

Cogeneration

Like most other things in Bosnia and Herzegovina, cogeneration policies follow the administrative organization of Bosnia and Herzegovina. General framework defined by Law on Usage of Renewable Energy Sources and Efficient Cogeneration (FBiH entity) and the Law on Renewable Sources of Energy and Efficient Cogeneration (RS entity).

One of the key elements of the energy efficiency strategy as defined in the Framework strategy is the creation of conditions for highly efficient cogeneration as well as for the promotion and expansion of efficient district heating systems using waste heat, waste and renewable energy sources wherever possible and with economically viable terms. As one of 5 analyzed scenarios in the Framework Strategy is a "cogeneration scenario". A "cogeneration scenario" has not been deeply elaborated as other scenarios in the Framework Strategy because the scenario requires a very complex implementation and a number of conditions to be met so as to make the scenario sustainable in the long-term.

One of the larger projects under implementation (planned start of operation in 2021) is the one concerning the modernization of an on-site CHP plant at ArcelorMittal Zenica facilities (iron & steel making plant). The project will replace and modernize the existing CHP and provide sustainable source of power and heat for the City of Zenica and the Arcelor Mittal Zenica facilities, and will substitute the use of coal with the use of process gases from

[18] Energy Efficiency Action Plan in Bosnia and Herzegovina 2016 – 2018
[19] https://www.energy-community.org/implementation/Bosnia_Herzegovina/EE.html
[20] https://energy-community.org/regionalinitiatives/infrastructure/investing.html
[21] Investing in Clean Energy in the Western Balkans; WBIF
[22] https://energy-community.org/regionalinitiatives/infrastructure/donors/Regional/REEP.html
[23] https://energy-community.org/regionalinitiatives/infrastructure/donors/Regional/GGF.html

the steelworks as fuel, and as a result achieve substantial reduction in CO_2 emissions, as well as improvement in dust content, NOx and SO_2 emissions. The CHP plant will have a power output of 14,45 MW and a heat capacity of 112,5 MW. [24]

Once it is commissioned in 2021, the new plant will produce all district heat for the city of Zenica as well as most of the energy needed in ArcelorMittal's steelworks.

Energy Investments Outlook

Actual major energy projects

Based on the latest news and information available to the public, the best estimate is made for the new energy projects from the Indicative Generation Development Plan[25] for the period from 2020 to 2029. In Table 5.48 "best estimation" of the indicative start of operation and status of the projects is presented.

Table 5.48 **RES installed capacity per source**

Type	Facility	Installed capacity (MW)	Estimated start of operation	Remarks
Hydro	HPP Ulog	35	2024	2024The EPC Contract, signed between EFT and Sinohydro Corporation Ltd (China), has entered into force on 20 December 2019.[26]
Hydro	HPP Vranduk	20	N/A	The project temporarily stopped due to unsuccessful negotiations on a settlement between Elektroprivreda BiH and Strabag (the contract terminated because parties did not agree with an additional works and payments on the project [27]). The start of the process at the International Court of Arbitration is expected. Further implementation of the project is uncertain.
Coal	TPP Tuzla 7	450	2026	Both houses of the FBiH Parliament approved (April 2019.) the proposed decision for the Federation of BiH to provide guarantees to Elektroprivreda BiH for a loan from the Export-Import Bank of China for the construction of Unit 7 in TPP Tuzla. The EPC contract was signed with China Gezhouba Group. Preparatory works on the construction of Unit 7 started on November 1st 2019.
Wind	WPP Podveležje	48	2021	The WPP id under construction. Elektroprivreda BiH has completed works on the construction of a transformer station and medium-voltage cable network. [28]
CHP	CHP ArcelorMittal Zenica [29]	14+112 (heat)	2021	The plant will produce all district heat for the city of Zenica as well as most of the energy needed in ArcelorMittal's steelworks. Project is under construction and start of operation is expected in 2021.[29]

Source: Annual report 2019, State of State Electricity Regulatory Commission in Bosnia and Herzegovina

[24] https://www.districtenergy.org/blogs/district-energy/2020/03/05/construction-of-new-chp-plant-in-zenica-starts-com
[25] Indicative Generation Development Plan for the period from 2020. to 2029., Jun 2019, Independent system Operator of Bosnia and Herzegovina
[26] http://www.eft-ulog.net/index.php/news/vjesti/commencement-of-ulog-hydropower-plant-construction
[27] https://www.sarajevotimes.com/austrian-company-strabag-has-filed-a-lawsuit-against-bosnian-electric-utility-company/
[28] https://www.epbih.ba/novost/29240/uskoro-pocetak-radova-na-iskopima-za-temelje-vjetroagregata-na-platou-podvelezja
[29] This project is in no way connected with the project KTG Zenica (387 MW gas power plant) which is practically stopped (no activity in recent years) due to various reasons

5

BULGARIA

Bulgaria

Economic and Political Background

Bulgaria's GDP fell at a more moderate pace of 3.8% in the fourth quarter of 2020, above the 5.2% contraction tallied in the third quarter, amid the gradual firming of activity. On a seasonally-adjusted quarter-on-quarter basis, growth slowed to 2.2% in Q4 2020 from 4.3% in the previous quarter. Taking the year as a whole, the country's economy contracted 4.2% in 2020 (2019: +3.7%), marking the first decline in activity since 2009.

The fourth quarter's annual result largely came on the back of an improvement in the external sector. Exports of goods and services declined at a slower pace of 11.2% year-on-year in Q4 (Q3: -20.8% y-o-y). In addition, imports of goods and services fell 0.8%, moderating from Q3's 4.3% fall.

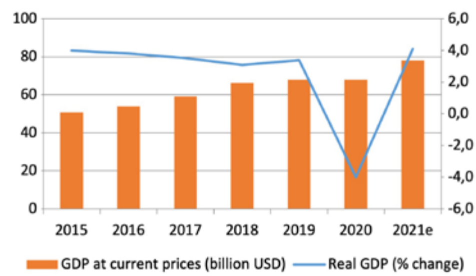
On the domestic front, total consumption growth eased to 0.9% in the fourth quarter from 2.7% in Q3. Meanwhile, fixed investment contracted at a sharper rate of 7.4% in Q4 2020, compared to the previous quarter's 6.4% decrease. IMF estimates that Bulgaria's GDP will expand by 4.1% in 2021, significantly higher than -4.0% in 2020.

General Parliamentary elections were held in Bulgaria on April 4, 2021. The results showed that the ruling right-wing party GERB again won the most votes and came out on top in the rankings. However, the future government is extremely unclear, as GERB does not have a majority to form an independent government. According to the election results, in the parliament enter five other parties and coalitions that have previously declared themselves in opposition to the ruling party so far with its leader Boyko Borissov.

On a second place with the most votes in parliament enter a completely new party called "There is such a people", created by the famous showman, TV presenter and singer Slavi Trifonov which has a categorical position that it will not form a coalition with any of the parties that have been present in the parliament so far – GERB, the Bulgarian Socialist Party and the Movement for Rights and Freedoms (MRF; primarily representing the country's Turkish minority).

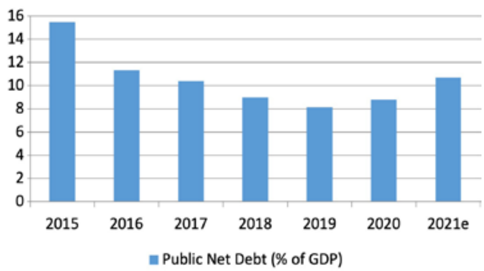
The biggest loss in these elections was suffered by the Bulgarian Socialist Party, which became the third political force and lost much of the support of its voters and respectively its influence in the parliament.

Figure 5.48 **Bulgaria's GDP and its annual GDP growth**



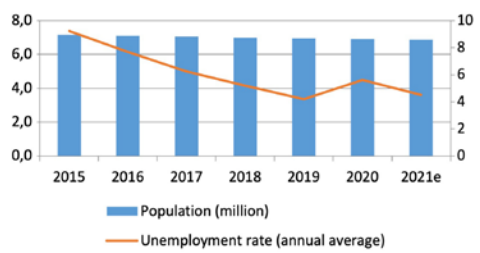
Source: IMF World Energy Outlook (October 2020)

Figure 5.49 **Bulgaria's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.50 **Bulgaria's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

Oil and Petroleum Products

A basic document for national energy policy in Bulgaria is the Energy Strategy (ES). The current ES was approved by the Council of Ministers and was voted through by the National Assembly of Bulgaria on June 01, 2011.

Based on the European targets "20-20-20 to 2020", the ES covers a horizon to 2020 and is designed to meet the main challenges faced by the Bulgarian energy sector. Namely: high energy intensity of GDP, high dependency on energy imports and the necessity for environmentally sound development. On that ground the main priorities in the ES are:

- to guarantee the security of energy supply;
- to attain the national targets for renewable energy;
- to increase energy efficiency;
- to develop a competitive energy market and
- to adopt policies for ensuring the energy needs;
- to protect the interests of consumers.

ES outlines specific sectoral policies and measures such as: diversification of the sources and routes for natural gas supplies (incl. support for indigenous resources exploration and exploitation), promotion of household gasification, cost efficient and sustainable achievement of the national 16% RES target, strong support for sound energy efficiency improvements along the entire energy chain of "production, transmission and consumption", sustainable development of centralized district heating, establishment of a competitive and integrated national energy market for electricity and natural gas.

In addition to the ES, in 2020 the government has adopted "an Integrated Energy and Climate Plan" in accordance with the Regulation on the governance of the energy union and climate action (EU)2018/1999, agreed as part of the Clean energy for all Europeans package which was adopted in 2019. Some of the main goals of the National Plan include:

- Achieve 27.09% of RES contribution to final energy consumption by 2030;
- Aim for a 27.89% decline in primary energy consumption in 2030 compared to 2007 and a 31.67% decline in final energy consumption;
- Aim for 0% decline in greenhouse gas emissions in 2030 compared to 2005;
- Achieve a 15% interconnection capacity of the electricity system.

In addition, the government envisages the adoption of a new Energy Strategy with a scope to 2030 and a horizon up to 2050. A draft of the Strategy is yet to be published and circulated for public consultation.

Governmental institutions

The National Assembly (NA) adopts the national ES and the main energy legislation, (energy law, law on energy from renewable sources and law on energy efficiency, etc.).

Within the Council of Ministers there are three ministerial bodies which are in charge of different aspects of national energy policy, in accordance with the adopted by NA energy legislation and ES. The Ministry of Energy (ME) is responsible for the implementation of the agreed national energy policy, and holds the main responsibilities for the implementation of the state energy policy and exercising ownership rights over state energy companies. The Ministry of Environment and Water has the responsibility for Climate Change and environmental protection policy while the Ministry of Regional Development and Public Works have particular responsibility on some residential and public energy efficiency programmes.

The Ministry of Economy is responsible for the implementation of government policy on building a competitive low-carbon economy, promotion and acceleration of investment, innovations and competitiveness.

The Sustainable Energy Development Agency is an executive agency within the ME, responsible for the implementation of state energy efficiency and RES policy.

The Energy and Water Regulatory Commission (EWRC) is the national regulatory authority for energy. Its main responsibilities are price setting, licensing & supervision, market monitoring. The Nuclear Regulatory Agency is the independent specialized authority, responsible for the state regulation of the safe use of nuclear energy and ionising radiation, the safety of radioactive waste management and the safety of spent fuel management.

Energy Demand and Supply

National energy demand

The Gross Inland Energy Consumption (GIC) has shown a steady increase in recent years and reached 19 mtoe in 2018 after decreasing to 16.8 mtoe in 2013, which was the statistical lowest level since 1990. Up until 2013, the dynamic was mainly driven by the stagnating economic growth due to lower external demand for Bulgarian goods, coupled with an internal political crisis. Economic growth started to pick up pace in 2014 and GIC followed shorty.

Typically for the country, the average ratio between Final Energy Consumption (FEC) and GIC is about 50%. Half of the energy is therefore lost in the transformation processes and the energy system's own use. Thus, there is a large potential for improvement after taking structural and efficiency measures, both on the production as well as on the consumption side. For comparison this ratio for the EU was 63.5% in 2018. However, it should be pointed out that Bulgaria's ratio has been increasing in the past couple of years and reached 51.4% in 2018.

As a result of the economic crisis, the FEC moved to its lowest level of 8.6 mtoe in 2009, followed by a slight recovery and stabilization in the next two years, although it has remained almost stagnant until 2014. Increasing economic growth in the past years has driven FEC in 2018 by almost 10% compared to 2014.

Table 5.49 **Energy Consumption (mtoe), 2014-2018**

	2014	2015	2016	2017	2018
Gross Energy Inland Consumption, (mtoe)	17.9	18.7	18.3	18.9	19.0
Final Energy Consumption (mtoe), incl. by sector	8.9	9.4	9.5	9.7	9.7
Industry	2.6	2.7	2.7	2.8	2.7
Transport	2.9	3.2	3.3	3.3	3.4
Services	1.0	1.1	1.2	1.2	1.2
Households	2.2	2.2	2.3	2.3	2.2
Agriculture	0.2	0.2	0.2	0.2	0.2

Source: Eurostat

National energy supply

The levels of primary energy consumption and energy imports were almost equal during the above period, although there have been exceptions e.g. 2016-2017. The proportion between primary energy production and energy imports varies substantially for the different resources. The local production of solid fuels is about 80% of the energy supply while the imports are 20% and correspond to oil and gas. Oil and natural gas imports are respectively 100% for crude oil supply and around 94% for the gas supply. Russia provides 100% of the imported gas and about 80% of crude oil.

During the above period the primary energy production has somewhat decreased from its all-time high of 12.3 mtoe in 2011 mainly due to lower production of solid fuels, mostly lignite. Solid fuels are used mainly for power generation needs. Energy imports, increased significantly in 2015-2017, and returned to average levels in 2018. Energy exports mostly electricity, remained relatively high in 2014-2017 and, in 2018, declined to their levels from 2010-2011.

Table 5.50 **Energy Supply, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
Production	11.3	12.0	11.3	11.7	12.0
Import	11.7	12.8	12.8	13.3	11.6
Export	5.4	5.9	5.7	5.8	4.7
Gross Inland Energy Consumption (GIC)	17.9	18.7	18.3	18.9	19.0

Source: Eurostat

Table 5.51 **Primary production of energy by resource, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
Production	11.3	12.0	11.3	11.7	12.0
Solid fuels	5.1	5.8	5.1	5.7	5.1
Total petroleum products	0.1	0.1	0.1	0.1	0.1
Natural gas	0.2	0.1	0.1	0.1	0.0
Nuclear heat	4.0	3.9	4.0	3.9	4.2
Renewable energy	1.9	2.1	2.0	1.9	2.6

Source: Eurostat

Energy mix

Bulgaria's energy mix appears well diversified since the country uses a wide variety of energy sources. Moreover, around 65% of the country's needs are covered by sources that are almost entirely domestic: solid fuels, renewables and nuclear.

Table 5.52 **Gross inland energy consumption by fuel type, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
Gross Energy Inland Consumption, (mtoe)	17.9	18.7	18.3	18.9	19.0
Solid fuels	6.4	6.6	5.7	6.1	5.6
Total petroleum products	4.0	4.3	4.3	4.5	4.6
Natural gas	2.4	2.6	2.7	2.8	2.6
Nuclear heat	4.0	3.9	4.0	3.9	4.2
Renewable energy	1.9	2.1	2.0	2.0	2.5
Waste (non-renewable)	0.0	0.0	0.0	0.0	0.1

Source: Eurostat

Although oil products were reduced in the FEC during 2010-2013, they still account for the largest share in the FEC, which has been increasing in recent years and reached 36% in 2018, compared to 32.3% in 2013. Although renewables and waste (biomass) steadily increased their share in FEC during 2010-2013 their share stagnated during 2014-2018. One of the main reasons is that the country reached its 2020 target in 2013, after which subsidies for new RES installations were almost completely suspended.

Table 5.53 **Final energy consumption by product, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
FEC by product	8.9	9.4	9.5	9.7	9.7
Solid fuels	0.3	0.3	0.3	0.4	0.4
Total petroleum products	2.9	3.2	3.2	3.4	3.5
Electricity	2.4	2.4	2.5	2.6	2.6
Natural Gas	1.2	1.3	1.3	1.4	1.3
Heat	0.9	0.8	0.8	0.7	0.5
Renewable energy	1.2	1.3	1.3	1.4	1.4

Source: Eurostat

Energy dependence

The energy dependency of the country over the last four years has fallen as low as 35.5% in 2014. It has increased in the following years up to 36.4% in 2018, however, it remains significantly lower than the EU average. Bulgaria has a high dependency on energy imports from Russia, concentrated in two energy sources: crude oil and natural gas. Improvement of the energy dependency indicator depends on local coal production and nuclear energy, which are considered as local resources.

Table 5.54 **Energy dependence, 2014-2018**

	2014	2015	2016	2017	2018
Energy Dependence	35.2	36.4	38.5	39.4	36.4

Source: Eurostat

According to the National Energy and Climate Plan 2021-2030, the results of the projections with existing measures are the following:

1. A decrease of GIC from 19.1 mtoe in 2020 to 18.4 mtoe in 2030;
2. A negligible increase of FEC from 10 mtoe in 2020 to 10.4 mtoe in 2030

These favourable deliverables and the separation of GDP growth from the energy growth could be achieved through the ambitious goals for energy efficiency improvement and a reduction of energy intensity by an annual 2.6% during the period 2020-2040.

Oil and Petroleum Products

(a) Oil Supply and Demand

Crude oil participated with an almost negligible share in primary energy production. However, oil is among the main sources of energy used in Bulgaria, with stable presence in GIC, at around 23.5% for the period 2014-2018, as it represents the main energy source for transportation.

Table 5.55 **Crude oil supply, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
Crude oil production	0.0	0.0	0.0	0.0	0.0
Import	5.2	6.2	6.3	7.0	6.0
Export	0.0	0.0	0.0	0.0	0.0
GIC crude oil	5.2	6.1	6.4	6.9	6.0

Source: Eurostat

Petroleum products participated in FEC with the highest share of 32-36% over the above period. Traditionally, the main consumer of petroleum products is the transport sector, particularly road transport, with a share of about 83-87% in FEC.

Table 5.56 **Final energy consumption of petroleum products, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
FEC of Total Petroleum products	2.9	3.2	3.2	3.4	3.5
of transport sector	2.5	2.8	2.9	2.9	3.0
of road transport	2.5	2.8	2.8	2.8	2.9

Source: Eurostat

(b) Oil Imports / Dependence

The country is entirely dependent on imports for the supply of crude oil. The major trading partners are Russia and Ukraine, which combined amount to more than 90% of the country's total imports and hence, the geographical diversification of oil supplies is rather limited. The rest of the oil supplies are imported from: Malta, Turkey, Kazakhstan, Egypt. The degree of petroleum products energy dependence is among the highest in the EU. The indicator has remained broadly stable during 2014-2018 with negligible fluctuations.

Table 5.57 **Energy dependence of total petroleum products (%), 2014-2018**

	2014	2015	2016	2017	2018
Energy dependence of total petroleum products	99.0%	100.5%	99.0%	101.1%	99.5%

Source: Eurostat

(c) Upstream Sector - Domestic Production and Exploration

There is not any significant oil production from indigenous sources in Bulgaria.

(d) Downstream and Midstream Sectors Infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

Refineries

The main oil refinery in Bulgaria and one of the biggest in the Balkan peninsula is owned by Lukoil Neftochim Burgas AD and is located in Burgas. It has a primary processing capacity of 9.5 Mt of crude oil per year and supplies liquid fuels, petrochemicals and polymers, being among the leading suppliers of petroleum products in the Balkan region and also distributes motor fuels to the rest of Europe & USA. There are three other manufacturers of petroleum products - "Bulgarian Oil Refinery" EOOD, "INSA Oil" Ltd. and "Polisan" AD.

Pipelines, terminals, storage facilities

Oil is imported through Bulgaria's main port at Burgas, where both the oil terminal and refinery are connected by pipeline to several Bulgarian cities. Physical storage and movement of fuel from the refinery and importers to the retail market and to end-users is done through largescale storage infrastructure and logistics.
Lukoil is the sole company which owns and operates all pipelines, serving the geographical area from Burgas to Sofia with a branch to Asparuhovo, Varna. The pipeline is intended for the fuel supply of the domestic market only and is not connected to the neighbouring countries. In addition to the pipeline, the logistics system of Lukoil Bulgaria EOOD includes a well-developed

transport system for the wholesale supply of fuels through the use of railway transport, covering the territory of the country and even distribution to warehouses and infrastructure for retail sales in key cities. Thus the physical flow of fuel throughout the country is achieved.

Domestic market

The market is fully liberalized and all downstream oil trading companies in Bulgaria are privately owned. The market is highly competitive, where small market players also have a share. The previously state-owned downstream oil company Petrol AD was privatized in 1999. The biggest players in the market either operate their facilities themselves (gas stations), or assign them to operators or franchisees.

The volumes on the wholesale market are traded by companies that are also suppliers of petroleum products. Typically, this activity is carried out directly or through other companies that perform the role of midstream players. Imported or domestically produced quantities reach the retail market (end users), either directly or through the channelling of products in the wholesale market. The customers in the wholesale market purchase products from tax warehouses (also known as excise warehouses) for storage (storage facilities); it is mandatory for imported fuels to be unloaded and stored in these tax warehouses before they enter the retail market. Tax warehouses enjoy a special tax regime and are under the control of the Customs Agency as they are in charge of collecting excise duties, while the National Revenue Agency is in charge of other taxes such as VAT, income taxes, social and health insurance benefits, etc. The most important market players are: Lukoil, Petrol, OMV, Shell, Naftex, Prista Oil, Hellenic Petroleum, Rompetrol, NIS Petroleum (Gazprom), Eco Bulgaria, Bulmarket DM, Vitogaz, Kalvacha Gas, Synergon Petroleum, Gastrade, INSA Oil.

The major player on the wholesale market is Lukoil Bulgaria, which is the biggest trader in the market. The company is vertically integrated with a refinery, petroleum products pipeline infrastructure, wholesale and retail suppliers, and located within the boundaries of the national market. The company also, directly or indirectly, owns over 80% of the capacity of tax warehouses for storing gasoline and diesel fuels. Traders on the wholesale market, other than Lukoil, include Rompetrol, Naftex Petrol, OMV Bulgaria, and Eco Bulgaria, which engage in imports from neighbouring refineries located in Romania and Greece.

(e) Security of Supply

The state controlled State Reserve and War-Time Stocks Agency maintains, in compliance with the relevant EU Directive Obligation, oil stocks in Bulgaria equivalent to 90-days average local consumption.

(f) Planned New Projects

Bulgaria's plan to participate in projects for the construction of crude oil pipelines such as the Burgas-Alexandroupolis and AMBO have dragged in time. In December 2011, the Bulgarian government withdrew from the Burgas-Alexandroplis project as a result of protests and a local referendum, on environmental grounds. The development of the second project - AMBO - was also suspended. The failure of these two projects is likely to reduce the country's ability to access alternative sources of crude oil over the coming years.The availability of an oil processing infrastructure and the country's ability to transport and distribute petroleum products in stable volumes, as well as the large investments in its expansion and modernization, offer grounds for optimism both in terms of security and future market development. This forecast is further supported by the current full liberalization of the oil market, ensuring the free movement of energy flows and products.

The transport sector, especially road transport, in Bulgaria is responsible for almost the entire FEC of petroleum products. Considering the lack of policy on energy efficiency improvement in the transport sector, no change should be expected in oil demand trends for the foreseeable future[1].

1 The WEM scenario projects an almost constant consumption of oil products in the period 2020-2030.

Natural Gas

(a) NG Supply and Demand (in bcm)

Natural gas had an almost constant share of just under 14% in Gross Inland Consumption during the period of 2014-2018. Electricity and heat generation were responsible for 32% of natural gas use. The non-energy use of natural gas in chemical industry accounted for around 8% of gross inland consumption of natural gas.

FEC natural gas consumption had been declining since 2011 due to the lower demand by the industrial sector. However, with economic activity picking up pace in 2014, FEC has increased slightly in recent years. Only 3.5% of the natural gas is consumed by households.

Table 5.58 **Natural gas demand, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
GIC natural gas	2.4	2.6	2.7	2.8	2.6
Power Generation	1.2	1.3	1.3	1.4	1.3
Industry	0.8	0.9	0.9	0.9	0.9
Transport	0.2	0.2	0.2	0.2	0.2
Households	0.0	0.1	0.1	0.1	0.1
Services	0.1	0.1	0.1	0.1	0.1

Source: Eurostat

Bulgaria has been producing natural gas from its continental shelf in the Black Sea since 2001. The increase of local production in 2011 and 2012 follows the development of new fields in Kaliakra and Kavarna, however, in recent years production has been declining. A small part (1-3%) of the inland consumption of natural gas is covered from local sources. The country relies mostly on natural gas imports to meet its domestic demand.

Table 5.59 **Natural gas supply, mtoe, 2014-2018**

	2014	2015	2016	2017	2018
Production	0.2	0.1	0.1	0.1	0.0
Imports	2.2	2.5	2.6	2.7	2.6
Export	0.0	0.0	0.0	0.0	0.0
Stock Changes	0.0	0.0	0.0	0.0	0.0
Gross Inland Consumption	2.4	2.6	2.7	2.8	2.6

Source: Eurostat

(b) NG Imports (in bcm)

The sole exporter of natural gas to Bulgaria is Russia. Bulgaria also acts as a transit route for Russian gas destined for Turkey, Greece and North Macedonia. Natural gas imports were almost stable during 2014-2018, albeit higher than compared to 2010-2013. The import of natural gas is based on long term "take-or-pay" contracts between Bulgargaz (Bulgaria) and RAO Gazprom (Russia) and covers exclusively inland consumption needs. The latter was abolished as part of commitments related to the European Commission's antitrust «CASE AT.39816 - Upstream gas supplies in Central and Eastern Europe».

(c) Dependence (%)

Being nearly 100% dependent on gas imports from Russia via a single route, Bulgaria continued to be vulnerable to gas supply disruptions over the period 2015-2019. The realization of new interconnection projects with neighbouring countries is likely to contribute both to the diversification of routes and, partially, suppliers over the next 5 years.

Table 5.60 **Energy dependence of total petroleum products (%), 2014-2018**

	2014	2015	2016	2017	2018
Energy dependence of natural gas	94.1%	97.0%	96.5%	97.6%	98.7%

Source: Eurostat

(d) Domestic Production and Exploration

Currently there are thirteen concession contracts[2] for gas exploration and production. The gas fields are located mainly on the north and north-east of Bulgaria. The main exploration and production companies are Melrose Resources, Oil and Gas Exploration and Production, and Direct Petroleum. The map below illustrates the current oil & gas exploration fields in Bulgaria.

[2] Concession Register of Bulgarian Ministry of Energy

Map 5.8 **Current oil & gas exploration fields in Bulgaria**

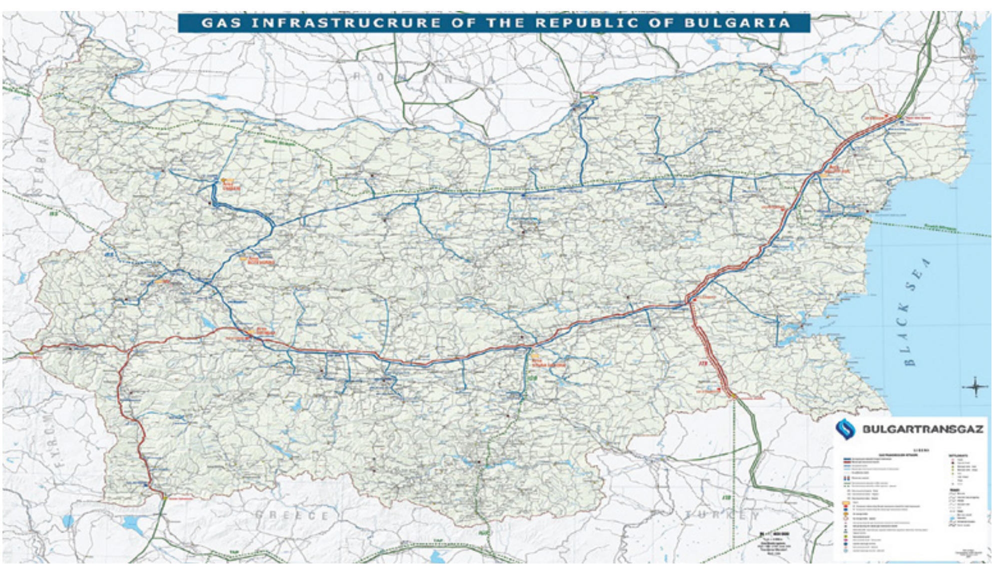
Source: Ministry of Energy

(e) Infrastructure (Pipelines, Storage)

The national gas transmission network is built in a ring-shaped form consisting of high pressure gas pipelines with a total length of 1700 km and three compressor stations with installed capacity of 49 MWt. Its technical transport capacity amounts to 7.4 bcm/year, and the maximum working pressure is 54 bar. The transit gas transmission network comprises high pressure gas pipelines of 945 km total length, six compressor stations with total installed capacity of 214 MW.

The total technical capacity for natural gas transit transmission amounts to 18.7 bcm/year and the maximum working pressure is 54 bar.The underground gas storage Chiren, is located near the city of Vratsa. It consists of 22 exploitation wells, a compressor station with an installed capacity of 10 MW and other equipment required to secure the injection, withdrawal and quality of stored gas. The development of low pressure gas distribution network in Bulgaria started in the last decade and its length is currently over 3,500 km.

Map 5.9 **Current gas infrastructure in Bulgaria**



Source: Bulgartransgaz

(f) Domestic Gas Market

Bulgartransgaz is the owner and operator of the national gas transmission network and of the Chiren single underground storage. Bulgartransgaz is also responsible for the administration of the natural gas market and balancing market under Natural Gas Trading Rules. The company is a 100% subsidiary of the state owned Bulgarian Energy Holding (BEH) and is under process of certification as an independent transmission operator under the Energy Law, transposing the requirements of Gas Directive 2009/73/EC.

Bulgargaz, which is a subsidiary of the BEH, is a single supplier and a public provider of natural gas for the whole country. Although there are rules and procedures stipulating the free access to the national grid, there have not been companies taking advantage of this facility.

In January 2019, the Gas Hub Balkan EAD company was established by Bulgartransgaz EAD (the state-owned Natural Gas Transmission System Operator) in line with the implementation of the concept for establishing a gas distribution center in Bulgaria. Furthermore, the company has started stock exchange trading in December 2019. The company operates trading platforms for the needs of the natural gas markets within the Balkan Gas Hub. In synergy with the physical infrastructure of the gas distribution center, the company provides the necessary prerequisites for the construction of the first liquid physical and commercial gas hub in the region of Southeast Europe, based in Bulgaria.

Gas distribution is performed by private regional and local companies, which perform licensed activities of gas distribution and supply for final consumers, connected to the gas distribution grids. However, Bulgaria's gas distribution network is not well developed with about 17% of natural gas consumption corresponding to customers of the distribution companies[3].

[3] Editor's note: Please clarify

(g) National NG Policy -Strategic Plan, Planned new projects

Diversification of sources and routes for the supply of natural gas is important for the country's energy security and independence. According to the ES (2011) the country will strive to build reverse interconnections with Greece, Turkey, and Serbia and will look into possibilities for the extension of the existing gas storage at Chiren, as well as for building of a new storage facility in Galata. There is already an interconnection with the Romanian transmission system, established in 2016, but the compression station on the Romanian side is still to be put into operation. The National Energy and Climate Plan 2021-2030 has the same goals as the ES.

The interconnections with Greece and Serbia, as well as increasing Chiren's capacity are included in the list of EU Projects of Common Interest (PCI) and have received grant support for feasibility studies and construction works under the European Energy Programme for Recovery, the European Fund for Regional Development and the Connecting Europe Facility. Bulgaria, via its transmission system operator, secured a 20% share in the LNG terminal at Alexandrupolis - another PCI project. Gas Hub Balkan was developed with the assistance of the European Commission and envisages the construction of a natural gas distribution center on the territory of Bulgaria, including the necessary gas transmission infrastructure, and an energy exchange for natural gas trade. The gas distribution center will connect the natural gas markets of Hungary, Croatia, Slovenia and through them the Member States of Central and Western Europe and the countries of the Energy Community - Serbia, Northern Macedonia, Bosnia and Herzegovina.
It is expected that through the implementation of ongoing or forthcoming projects aiming at diversification of routes and sources of gas supply (participation in transnational gas corridors, interconnectors with the neighbouring countries and access to LNG terminals and storages), continuing development of production from domestic reserves and energy security of domestic consumers will be guaranteed.

A priority of the ES and the National Energy and Climate Plan 2021-2030 is the development and extension of households' gasification. On the one hand, this will increase gas imports, increasing gas dependency, but on the other hand, higher use of natural gas will improve the energy efficiency ratios as less energy will be lost in transformation processes.

Solid Fuels

(a) Supply and consumption

The local production of solid fuels varied between 97-99% of the Gross Inland Energy during 2015-2019. Due to the high production and import requirements the supply of solid fuels reached its highest level in 2011 (since 1991) and has declined gradually in the last five years to 28.7 Mt, which is close to its 2010 level.

Table 5.61 **Solid fuels supply, Mt, 2010-2014**

	2014	2015	2016	2017	2018
Production	36.8	32.5	35.5	31.2	28.7
Import	1.1	0.9	1.0	0.9	0.6
Export	0.0	0.0	0.0	0.0	0.1
Stock changes	0.0	-0.1	-0.7	-0.4	-0.1
GIC solid fuels	37.9	33.3	35.8	32.0	29.5

Source: Eurostat

The majority of coal is used in the power sector with over 97% consumption and the rest is used for household heating and small industrial consumers. Environmental problems driven by the use of solid fuels for power generation are the main challenges facing solid fuels. Coal burning thermal power plants are responsible for emitting approximately 80% of national emissions of sulphur oxides and about 60% of carbon dioxide.

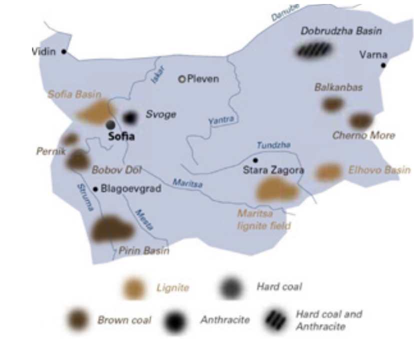
Table 5.62 **Solid Fuels Consumption, Mt, 2014-2018**

	2014	2015	2016	2017	2018
GIC solid fuels	37.9	33.3	35.8	32.0	29.5
FEC solid fuels	0.6	0.6	0.5	0.6	0.6

Source: Eurostat

Opencast lignite mining is carried out in the state owned mine of Mini Maritsa Iztok EAD, whose production amounts to approximately 95% of the total inland lignite output. The transportation of lignite over long distances is not considered profitable. Five large lignite fired plants operate adjacent to the Mini Maritsa Iztok lignite mine. There are some other smaller and privately owned local lignite mining companies. Production of brown coal corresponds to approximately 7% of total indigenous production. This production is mainly concentrated in the Western part of the country.

Map 5.10 **Distribution of coal reserves in Bulgaria**



Source: Eurocoal

Table 5.63 **Solid fuels production, Mt, 2015-2019**

	2015	2016	2017	2018	2019
Lignite & brown	35.9	31.2	34.3	30.3	28.0

Source: Eurostat

(b) Deposits

The proven geological lignite and brown reserves which are economically and technically exploitable in the short to medium term according to Euracoal for 2017, are respectively 2,174 Mt and 192 Mt. The entire amount of estimated lignite reserves, which are not economically and technically minable, amount to 4,574 Mt.

Table 5.64 **Coal resources and reserves, Mt, 2017***

Resources hard (black and brown) coal	4112
Resources lignite	4574
Reserves hard (black and brown) coal	192
Reserves lignite	2174

* Hard coal production is not significant (c.35 thousand tonnes) and is carried out by MINA BALKAN 2000 EAD

Source: Eurocoal

(c) Coal imports

Since 2010 the share of imports in solid fuels supply decreased from 10% to 5%. About 5% of the generated electricity comes from imported thermal coal. This trend has continued during the period 2015-2019, and the share of imports in 2019 reached 2.1%. The main reason is that the power station which uses imported thermal coal closed in the begging of 2015 due to environmental concerns. It reopened in 2018, however, with reduced capacity, mainly for providing a so-called cold reserve, through its natural gas-fired boilers. The environmental reasons have not been overcome, meaning that any increase in the producer's capacity will most likely be dependent on natural gas, rather than importing hard coal.

(d) Planned new projects - Coal Production Outlook

The future of local coal production depends on the development of the electricity generation, based on coal. Faced with the challenges of sustainable EU low-carbon policy, the coal production will depend on the competitive positions of coal-fired power plants in the country. Carbon Capture and Storage (CCS) technologies create prospects for this type of electricity generation, but currently they exist only at demonstration level, since they are not yet in commercial use.

Coal-fired power plants are even now struggling with high prices of CO_2 allowances and will be further hit by new environmental requirements to emission caps. The WEM (NECP) projects the reduction of the generation from coal of around 25% (with respect to the value of 2020), and to almost phase out coal-fired generation by 2040 (-90% with respect to the value in 2020).

Electricity

(a) Electricity Supply and Demand (TWh)

Bulgarian gross electricity generation reached 49.2TWh in 2015, which has declined in the following years below its 2012-2014 levels. Gross inland consumption also shrank to 33.6 TWh or about 75% of the gross electricity generation.

Although exports comprise a considerable part of gross electricity generation, their share has decreased from 30% in 2015 to 20% in 2019.

Table 5.65 **Gross electricity generation, Twh, 2015-2019**

	2015	2016	2017	2018	2019
Gross electricity generation	49.2	45.3	45.6	46.8	44.2
Import	4.3	4.6	3.7	2.2	3.0
Export	14.8	10.9	9.2	10.0	8.9
Net supply (generation + import - export) before losses	33.4	33.8	34.9	34.5	33.6

Source: Eurostat

The final electricity consumption has been increasing from 56% of the gross inland consumption in 2015 to 68% in 2019, however, it remains below its level during 2010-2013 of 77%.

The business and public sector consumption corresponds to about 63% of the final electricity consumption of the country.

Table 5.66 **Final electricity consumption, TWh, 2014-2018**

	2014	2015	2016	2017	2018
Final energy consumption, including	27.7	28.3	28.9	29.9	29.9
Business and public sector	17.1	17.7	18.2	18.8	18.9
Households	10.6	10.6	10.7	11.1	11.0

Source: Eurostat

(b) Installed Capacity

Although fossil fuels continued to cover a significant part of the generating capacities of the country, they were slightly losing their position during the period of 2010-2014 due to the rise of renewable energy sources. This process was further exacerbated by the increased prices of CO_2 allowances and the declining share of free allowances allocated to thermal plants. Fossil fuel capacity has stabilized at around 44% of total generating capacity in the last five years.

Although 2012 was a remarkable year for solar power development when the total installed capacity increased almost seven-fold, making Bulgaria a world leader in new solar capacity per GDP and per capita. RES capacity installations have stalled since 2013 following social unrest related to preferential pricing, attainment of the 2020 RES target, as well as unstable investment environment. It is reasonable to expect a renewed interest in RES investment due to replacements of older generating installations as well as new stimuli that can be introduced in order for the country to meet its 2030 RES target.

Table 5.67 **Generating capacity MW, 2015-2019**

	2015	2016	2017	2018	2019
Fossil fuels	5,706	5,683	5,048	5,468	5,713
Nuclear	2,000	2,000	2,000	2,000	2,000
Hydro	3,198	3,204	3,204	3,208	3,211
Renewables, incl.	1,806	1,813	1,821	1,826	1,833
Solar PV	1,041	1,043	1,046	1,052	1,059
Wind	701	701	701	700	700
Biomass	64	69	74	74	74
Total	12,710	12,700	12,073	12,502	12,757

Source: ENTSO-E Transparency Platform

(c) Planned New Capacity

In the recently updated Ten-Year Network Development Plan 2020-2029 the Bulgarian Electricity System Operator forecasted between -2.3% and 6.9% higher electricity consumption by 2029 compared to 2019 and a potential for electricity exports at around 100-300 MWh, which is a considerable setback compared to the Development Plan 2015-2024 envisioning experts of around 10 TWh.

Over the next 10 years the Electricity Transmission System Operator does not envision a change in the Nuclear Power Plant installed capacity, meaning that no new projects, such as NPP Belene or a new generation at the Kozloduy plant, can be expected. Thermal power plant net capacity is expected to decline by 63%, while gas-fired net capacity is projected to increase by 25%.

The largest increase is expected in RES net capacity:

• Biomass: 2020 - 80 MW; 2029 - 292 MW;
• Wind: 2020 - 699 MW; 2029 - 908 MW;
• Solar PV: 2020 - 1042 MW; 2029 - 2930 MW.

(d) Electricity Imports - Exports

Traditionally, Bulgaria is a net electricity exporter. Electricity exports grew to 14.8 TWh in 2015, which was the highest level since 2001, but, they have gradually dropped to 9.0 TWh in 2019. It is worth noting that the NECP reports an almost constant projection for electricity export over the next years.

Electricity imports continued their upward trend until 2016, and have declined since - in 2019 they were around their 2012 level. The growth of electricity imports and exports is evidence of the opening of electricity market to neighbouring markets, including the establishment of an electricity exchange in 2016. Further integration of the regional markets and development of electricity exchanges can lead to increased cross-border trading.

(e) Tariffs

In Bulgaria, electricity prices for households are regulated. For low voltage business customers prices used to be regulated, but following a with a recent reform they are forced to choose a market supplier by the end of June 2021, otherwise they will be forced to purchase their electricity from the Supplier of Last Resort. The country has integral electricity tariffs[4] covering all electricity costs including power generation, transmission, distribution, supply, support to renewables, etc. After social unrest in the winter of 2013 the decisions of the Energy and Water Regulatory Commission led to the buildup of a considerable tariff deficit, which has since narrowed down over the past five years through the increase of different tariffs. Nevertheless, these decisions have alleviated only the current tariff deficit, while there is still the problem of financing past deficits, which were most severe in the period June 2013 - June 2015.

[4] Source: Electricity tariff deficit : Temporary or permanent problem in the EU (http://ec.europa.eu/economy_finance/publications/economic_paper/2014/pdf/ecp534_en.pdf)

Table 5.68 **Electricity price components for domestic consumers for the second half of the year (euro/ KWh) Band DC: 2 500 kWh < Consumption < 5 000 kWh**

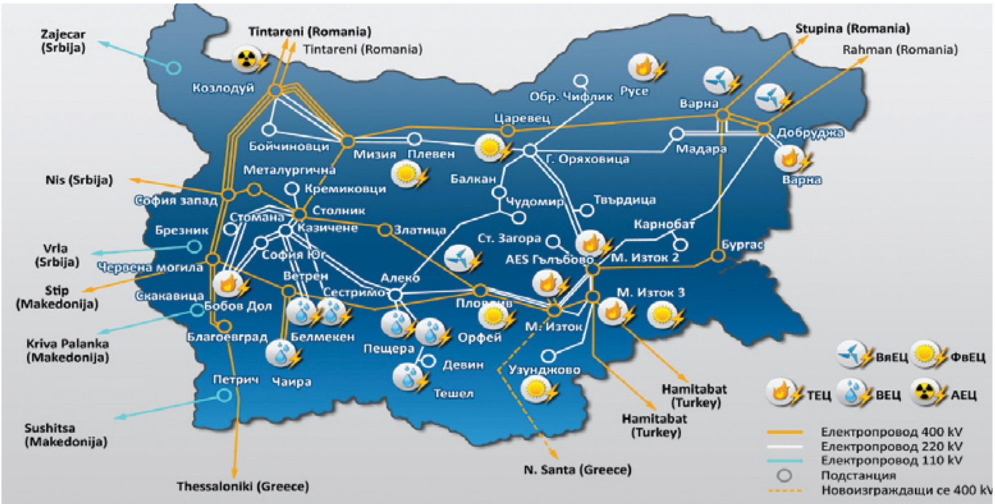
	2015	2016	2017	2018	2019
Energy & Supply	0.0577	0.0552	0.0575	0.0585	0.0558
Network costs	0.0220	0.0230	0.0232	0.0242	0.0256
Taxes and levies	0.0160	0.0156	0.0162	0.0165	0.0163
Total	0.0957	0.0938	0.0969	0.0992	0.0977

Source: Eurostat

(f) Cross-Border Interconnections

The existing international interconnectors in the Bulgarian power system provide the necessary technical prerequisites for significant electricity exchange volumes under both normal and unstable operating conditions, including emergency cases by tripping the 1,000 MW unit at Kozloduy NPP. Current interconnection capacity is around 7% of installed generation capacity and the National Energy and Climate Plan 2021-2030 has a goal of increasing it to 15%.

Map 5.11 **Existing interconnectors in the Bulgarian power system**



Source: Eurocoal

Table 5.69 **H/V Interconnections of the Bulgarian electricity system**

Nominal Voltage,kV	Neighbour country	Bulgarian S/S	Neighbour S/S	Neighbour TSO	Lenght km	Parallel operation	Cross section	Thermal rating, A
400 kV	Romania	Dobrudzha	Rahman	TEL	175,19	Yes	3 x ACO 400	2475
400 kV	Romania	Kozloduy	Tintareni	TEL	115,7	Yes	2 x ACO 500	1890
400 kV	Romania	Kozloduy	Tintareni	TEL	115,7	Yes	2 x ACO 500	1890
400 kV	Romania	Varna	Stupina	TEL	152,81	Yes	5 x ACO 300	2835
400 kV	Serbia	Sofia West	Nis	EMS	122,5	Yes	2 x ACO 500	1890
400 kV	North Macedonia	Chervena Mogila	Stip	MEPSO	150,1	Yes	2 x ACO 500	1890
400 kV	Greece	Blagoevgrad	Thessaloniki	IPTO	176,8	Yes	2 x ACO 500	1890
400 kV	Turkey	Maritsa East 3	Hamitabat	TEIAS	148,8	Yes	3 x ACO 400	2475
400 kV	Turkey	Maritsa East 3	Hamitabat	TEIAS	158,8	Yes	2 x ACO 500	1890
110 kV	Serbia	Kula	Zajecar	EMS	20,2	No	AC 185	510
110 kV	Serbia	Breznik	Vrla	EMS	64,1	No	AC 185	510
110 kV	North Macedonia	Skakavitsa	Kriva Palanka	MEPSO	18,1	No	ACO 400	825
110 kV	North Macedonia	Petrich	Susica	MEPSO	32,6	No	ACO 400	825

Source: Electricity Transmission System Operator

(g) Planned New Projects

There are several PCI's included within the guidelines for Trans-European energy infrastructure projects, to be developed as part of electricity interconnections with Greece and Romania upon whose completion there will be an increase of the cross-border capacity and will help to open up the North-South priority corridor.

Table 5.70 **Bulgaria's Electricity PCI Projects**

Name	Summary project information
Internal line between Dobrudja and Burgas	It belongs to Cluster Bulgaria Romania capacity increase. Construction of a new 400kV AC single-circuit line (OHL) of 140 km and with a capacity of 1700 MVA connecting Dobrudja and Burgas (onshore)
Internal line between Maritsa East 1 and Bourgas	It belongs to Cluster Bulgaria - Greece between Maritsa East1 and N. Santa. Construction of a new 400 kV AC line (OHL) of 150 km and with a capacity of 1700 MVA between Maritsa East 1 and Burgas (onshore)
Interconnection between Maritsa East 1 (BG) and N. Santa (EL)	It belongs to Cluster Bulgaria - Greece between Maritsa East 1 and N. Santa. Construction of a new AC 400 kV single-circuit interconnector (OHL) with a length of 130 km and a capacity of 2000 MVA between Maritsa East 1 (BG) and Nea Santa (EL) (onshore)
Internal line between Maritsa East 1 and Maritsa East 3	It belongs to Cluster Bulgaria - Greece between Maritsa East 1 and N. Santa. Construction of a new 400 kV AC line (OHL) of 13 km and with a capacity of 1700MVA between Maritsa East 1 and Maritsa East 3 (onshore)
Internal line between Maritsa East and Plovdiv	It belongs to Cluster Bulgaria - Greece between Maritsa East 1 and N. Santa. A new AC 400kV line (OHL) between Maritsa East and Plovdiv with a length of 94 km and a capacity of 1700 MVA (onshore)

Source: Electricity Transmission System Operator

Electricity Imports Outlook

Given the "non-regret" EU low-carbon policy an increase is expected of carbon free generation through the development of RES and nuclear power. However, the capabilities of the electricity system are not evenly distributed throughout the year and during prolonged cold spells in the winter the system might need to resort to using its tertiary reserves or imports of electricity.

Renewables

(a) Overview of Sector's Development

According to the RES Directive 2009/28/EC and the National Renewable Energy Action Plan, Bulgaria is required to achieve a national target of 16% share of renewable energy in gross final consumption of energy by 2020. Bulgaria is among the three countries which have already reported fulfilment of the target. According to the latest Eurostat data, Bulgaria's renewable energy target for 2020 has already been fulfilled since 2013, and in 2018 their share was 20.5%.

The factors which contributed to the significant rise of RES in the gross final consumption of energy in in the past years, are the following:

- Increased consumption of renewable energy (biomass) for heating
- The renewable energy consumption for heating and cooling purposes in 2018 exceeded the 2020 goal for this sector (heating and cooling) by over 50% (or 12.7 percentage points). This is the result of the direct use of biomass (forest wood) for heating purposes in households.
- Significant growth in RES for electricity generation.
- The RES share in electricity in 2018 was about 2 percentage points below the 2020 target (for the electricity sector).
- Decreasing gross final consumption of energy.

Table 5.71 **Grosstime energy consumption in 2018**

	Share of RES in Gross Final Energy Consumption in 2018	National target 2020
Electricity	22.1%	23.8%
Heating&cooling	33.3%	20.6%
Transport	8.1%	10.0%
Total	20.5%	16.0%

Source: Eurostat

(b) Latest Legislation, Incentives and National RES Policy

The promotion of renewable energy in Bulgaria is foreseen by Energy Act (EA) and the Law on energy from renewable sources (LERS). National support measures for RES producers include mandatory priority connection to the grid, priority dispatching and the obligatory purchase of their net specific electricity production, which is determined by the regulator based on technology and date of connection to the grid, at preferential prices, also set by the EWRC (Feed-in Tariffs). All RES producers which sell electricity at preferential prices must apply and obtain certificates of origin for the generated energy. These certificates are issued by SEDA.

Since the beginning of 2018 all producers with installed capacity of no less than 5 MW were obliged to sell their electricity, not intended for the regulated market, on the Independent Bulgarian Energy Exchange (IBEX). As of July 2018 the 5 MW threshold was lowered to 4 MW and RES producers no longer have a production quota for the regulated market. They now sell all their electricity on the IBEX, and for quantities up to their yearly net specific production they receive a Feed-in Premium, rather than the Feed-in Tariff, which they received until June 2018. In this way the support mechanism for RES changed from a Feed-in Tariff (or a preferential price) paid to each producer for their yearly net specific production, all of which was sold on the regulated market, to Feed-in Premium, which is the difference between the Feed-in Tariff and a projected average market price, determined by the Energy and Water Regulatory Commission. Hence, as of June 2019 the scope of producers has broadened, to RES producers with installed capacity of no less than 1 MW.

Overall, the promotion of renewable energy for heating and cooling is not well developed. Project development of local heating distribution networks and small decentralized heating and/or cooling shall benefit from incentive measures but they are not yet foreseen in the legislation.

(c) Installed Capacity per Source (in MW)

Installed electricity capacities have stagnated in recent years as the 2020 RES target was achieved much earlier and the preferential treatment of investors was significantly reduced.

Table 5.72 **Installed RES capacity per source, MW, 2015-2019**

	2015	2016	2017	2018	2019
Hydro	**3,198**	**3,204**	**3,204**	**3,208**	**3,211**
Renewables	**1,806**	**1,813**	**1,821**	**1,826**	**1,833**
Solar PV	1,041	1,043	1,046	1,052	1,059
Wind	701	701	701	700	700
Biomass	64	69	74	74	74
Total	**5,004**	**5,017**	**5,025**	**5,034**	**5,044**

Source: ENTSO-E Transparency Platform

(d) Planned New Major Projects - RES Market Outlook

There are no new major projects planned. However, the Electricity Transmission System Operator anticipates some 1,888 MW of new Solar PV, 200 MW of extra Wind Power and 210 MW of additional Biomass in generating capacity to be integrated into the grid during the period 2020-2029.

Energy Efficiency and Cogeneration

(a) National Targets

Energy Efficiency: The National Energy and Climate Plan 2021-2030 sets measures and policies which should lead to a 32.5% improvement in energy efficiency, resulting in savings of more than 8,325 GWh of energy by 2030. Expressed in absolute terms, Bulgaria aims to reduce the energy intensity of its GDP by 2,6% annually during the period 2020-2040. The country has tried to reach its 2020 EE target through an Obligation Scheme and Obligated Parties, as well as Alternative

Measures. However, there is no adequate financial compensation mechanism in place and the Obligated Parties are reluctant to make large investments, as they cannot achieve a break even on their investments. As a result, in recent years, the government has tried to increase the share of Alternative Measures in reaching its 2020 target.

Cogeneration: The National Plan projects a significant increase in biomass for heat production due to the development of cogeneration plants (from 4 GWh in 2020 to 2497 GWh in 2030).

(b) Incentive-based Initiatives in the Building Sector (planned or already in place)

The Bulgarian Law on Local Energy Levies and Taxes envisages some incentive-based measures in the building sector, addressed to owners of buildings with energy performance certificates from class A to class D. These owners can be exempted from building tax payment obligations for a limited period of 3 to 10 years depending on the type of certificates, the year of issuance of building exploitation permission and RES integration.

(c) EU Funded (or otherwise funded) Energy Efficiency Programmes in the Building Sector and Planned New Major Projects

A National Programme for Energy Efficiency of Multi-Family Residential Buildings was approved in February 2015 with an initial budget of 1 bln. Euro and latter increased to 2 bln. Euro, aimed at financing energy efficiency measures, mainly upgrading. The programme was in place between 2015 and 2017. Currently, there are talks of restarting it with somewhat different parameters - both regarding financing and technical requirements, however, a decision is yet to be made.

Being one of the main problems of Bulgaria, energy efficiency is the focus of EU's Operational Programme "Regions in Growth"2014-2020 (OPRG). The special investment priority for energy efficiency and RES projects concerns public buildings, housing sector and student dormitories.

The Kozloduy International Decommissioning Support Fund (KIDSF) has been established, and administered by the European Bank for Reconstruction and Development (EBRD), in order to support the decommissioning activities and mitigate the negative consequences of nuclear units's 1-4 early closure. Part of the purpose of the KIDSF is to improve energy efficiency.

(d) Cogeneration: Regulatory Framework, Installed Capacity

The promotion of electricity production from high-efficient cogeneration in Bulgaria is required by the Energy Act (EA), transposing the relevant EU legislation. National support measures include priority connection of cogeneration capacities to the electricity grid and the obligatory purchase of the net electricity produced at preferential prices, set by the EWRC. All producers of electricity from highly-efficient cogeneration must obtain certificates of origin, for the generated quantities, issued by EWRC. As of January 2019, all such producers have to sell the electricity produced on the electricity exchange while the preferential prices were substituted with Feed-in Premiums.

The main CHP producers are district heating companies and industrial auto producers and both their electricity and heat capacity has been increased over the past five years.

Table 5.73 **Installed CHP capacities, MW, 2014-2018**

	2014	2015	2016	2017	2018
Gross Electricity Capacity	961	1121	1285	1046	1038
Net Heat Capacity	3400	3728	4122	3996	3977

Source: National Statistical Institute

Energy Legislation & Regulatory Framework

There is extensive legislation covering the fields of electricity generation, hydrocarbons and Renewable Energy Sources. This legislation is summarized as follows:

Electricity

The Energy Act provides for licensing regimes in the electricity sector.

Electricity prices in the balancing market as well as the price for the electricity supplied by the Supplier of Last Resort, are not determined by the Regulator (thus not subject to regulation in the strict sense), but are determined by the licensee for the respective activity under rules and methodology approved by the Regulator.
The requirements for the persons applying for a license are set forth in the Energy Act and the Ordinance for licensing of the activities in the energy field, State Gazette No. 33 of 5 April 2013 ("Licensing Regulation").

The Commission, in accordance with its powers, has approved the Rules for Trade with electricity (State Gazette No. 66 of 26 July 2013, as amended and supplemented).

The transmission and grid access are regulated by the Energy Act and a special Ordinance No. 6 of 12 December 2014, for the connection of producers and consumers of electricity to the electricity distribution and transmission networks (the "Connection Ordinance").

Hydrocarbons

The natural gas sector is regulated by the Energy Act and a number of Ordinances and Rules issued by the Council of Ministers and the Energy and Water Regulatory Commission. This legislation conforms to the fundamental EU guidelines in the sector.[5]

Renewables - Energy Efficiency

The Renewables Act basically preserves the principles of the previous system of encouragement and provides for some additional mechanisms for the encouragement of investments in renewable energy generation. It also preserves the system of encouragement for generation of electricity from renewables based on Feed-in Tariffs, later changed into Feed-in Premiums.[6]

5

CROATIA

Croatia

Economic and Political Background

Croatia's GDP fell at a milder, albeit still notable, pace of 7.0% year-on-year in the fourth quarter of 2020, improving from the 10.0% contraction seen in the third quarter. Q4's result marked the third successive quarter of contracting output, as lingering restrictions throughout most of the period weighed on activity. All in all, GDP tumbled 8.4% in 2020, contrasting 2019's 2.9% expansion and logging the worst reading in over two decades.

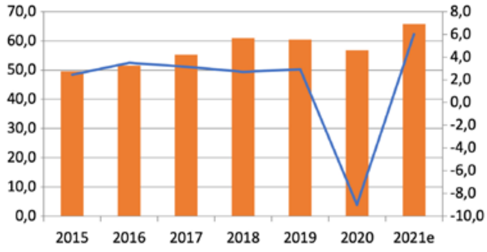
Q4's milder contraction reflected a broad-based improvement in private consumption, public spending, fixed investment and exports. Household spending fell 4.5% year-on-year in the final quarter, softening from Q3's 7.5% drop. In addition, fixed investment rebounded solidly in Q4, growing 4.2% and swinging from the 3.0% contraction tallied in the prior quarter. Meanwhile, government consumption edged up in the quarter, increasing 1.6% (Q3: +1.5% y-o-y).

On the external front, exports of goods and services fell 9.8% on an annual basis in the fourth quarter, softening markedly from the third quarter's 32.3% dive, amid firming foreign demand. In addition, imports of goods and services slid at a slower rate of 7.6% in Q4 (Q3: -14.1% y-o-y).

IMF estimates that Croatia's GDP will expand by 6.0% in 2021, significantly higher than -9.0% in 2020.

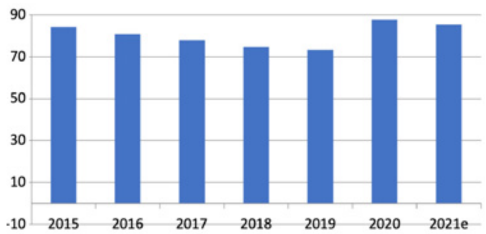
A judicial crisis emerged in March 2021 when President Zoran Milanović decided to support Zlata Đurđević as a candidate for the position of the Supreme Court's president. However, Đurđević was not among those who applied through the official procedure and, therefore, was not considered a candidate. This sprawled a long-lasting feud between the President and the government, while at the same time a new corruption issue in the Croatian judiciary occurred.

Figure 5.51 **Croatia's GDP and its annual GDP growth**



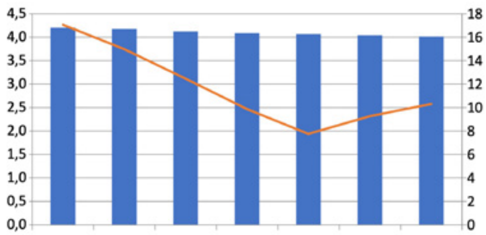
Source: IMF World Energy Outlook (October 2020)

Figure 5.52 **Croatia's Public Gross Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.53 **Croatia's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy

The basic act defining energy policy and planned energy sector development is the Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050, which was approved by the Croatian Parliament on February 28, 2020. The Energy Development Strategy is a step towards the realization of a low carbon vision and provides a transition to a new era of energy policy, ensuring an affordable, secure and high-quality energy supply, without any burden on the state budget or the need for state aid and incentives. The envisaged energy transition process will be capital intensive, with no incentive measures in terms of state aid, but with the expected greater involvement of the private sector/ capital in financing RES projects.

Croatia's energy policy and strategy is focused on achieving EU's goals in terms of reducing greenhouse gas emissions, increasing the share of RES, energy efficiency, security and quality of supply, and developing the EU's internal energy market, as well as making available the necessary resources, energy infrastructure and thus ensuring competitiveness of the economy and the energy sector.

The transformation of the energy sector into a low greenhouse gas system will involve all sectors of energy production and consumption, as well as systems that transmit and supply energy to customers. In their transformation, energy systems must continue to fulfil their primary purpose, which is secure supply of energy to all customers, at reasonable prices and with minimal environmental impact.

The main determinants of the pursued changes in the energy sector are the following:

- The strengthening of the energy market as a supporting component for the development of the energy sector. Emission unit prices is seen as a key economic mechanism for controlling the speed of transition.
- The full integration of Croatian energy market into the international energy market technology, research, services, production, and in particular EU's internal energy market.
- The strengthening of security of energy supply through the increase of domestic production and the integration of energy infrastructure, as well as the introduction of Capacity Remuneration Mechanisms (CRM).
- The increase of energy efficiency in all parts of the energy chain (production, transport/ transmission, distribution and consumption of all forms of energy).
- The continuous increase of the share of electricity in energy consumption with the aim of reducing fossil fuel consumption.
- The continuous increase of electricity production with reduced greenhouse gas emissions - primarily from RES.
- The development of the energy sector should be based on commercially available technologies, in particular hydroelectricity, sun and wind and other RES.
- The focus on financial support for the development of bioeconomy and sustainable waste management and research, on pilot and demonstration projects.
- The provision of risk mitigation funds for demanding technologies and new commercial technologies.

The Integrated National Energy and Climate Plan for the period 2021-2030 builds on existing national strategies and plans and takes into consideration the five dimensions of the Energy Union: decarbonisation, energy efficiency, energy security, the internal energy market and research, innovation and competitiveness. There are four key strategies, which address the five dimensions of the Energy Union. The first and second are covered in the **"Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050"** which defines the optimal energy mix and development projects with the aim of ensuring the energy independence of the Republic of Croatia, with particular emphasis placed on strengthening the production of energy from renewable sources. Also, special attention is paid to the security of supply, sustainability and competitiveness of the energy system.

The strategic document which deals with decarbonisation is the **Draft of the Low-Carbon Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050.** One of the objectives within the decarbonisation dimension is the adaptation to climate change, which is elaborated in the Draft of the Climate Change Adaptation Strategy in the Republic of Croatia until 2040 with an outlook to 2070 with the action plan.

The key document for the energy efficiency dimension is the **Long-Term Strategy to Encourage Investment in the Renovation of the National Building Stock of the Republic of Croatia by 2050**, which promotes the need to invest in the building stock. The revised strategy aligns the renovation objectives with the NECP in light of demographic trends and activities in the construction sector, with trends of accelerated abandonment of the existing building stock of poorer properties and gradual growth in new construction. The current energy renovation rate of 0.7% per year will gradually rise to 3% over the 2021-2030 period, with a 10-year average rate of 1.6%. An important element is the introduction of additional measurable indicators for the energy renovation of buildings, which will strengthen the process of conversion of the stock into nearly zero-energy buildings, i.e. climate neutral.

The dimensions of energy security and the internal energy market have been elaborated within the framework of the **Energy Development Strategy.**

The national strategies relevant to the dimension of research, innovation and competitiveness are the **Strategy of Education, Science and Technology, the Smart Specialization Strategy of the Republic of Croatia 2016 - 2020 and the Innovation Promotion Strategy of the Republic of Croatia 2014 - 2020.** With regard to these strategies, this document also outlines systematic measures expected to contribute to research, innovation and competitiveness of the Croatian economy in sectors relevant to the energy transition.

The key objectives outlined in the Integrated Energy and Climate Plan are the **reduction in greenhouse gas emissions in the Republic of Croatia for the year 2030, the share of RES in the gross final energy consumption and energy efficiency, expressed as consumption of primary energy and direct consumption of energy.**

Table 5.74 **Achieved emission reductions in 2017 and targets for 2030**

Scope	GHG emissions in 2005 (kt CO2e)	Achieved emissions reduction in 2017 compared to 2005	Target for the period 2013-2020 compared to 2005	Target for the period 2013-2020 compared to 2005
ETS sector	10,649	-21.4%	-21.4% (EU-wide target)	-21.4% (EU-wide target)
Non-ETS sectors	17,404	-4.2%	-10% (EU-wide target) +11% (target for Croatia)	-30% (EU-wide target) -7% (target for Croatia)

Source: Integrated National Energy and Climate Plan for the Republic of Croatia for the period 2021-2030

Table 5.75 **Estimated values of key indicators, Green Paper**

Scope	Target for 2030
Share of RES in the gross final consumptionof energy	36.4%
Primary energy consumption	8,216 ktoe
Final energy consumption	6,855 ktoe

Source: Integrated National Energy and Climate Plan for the Republic of Croatia for the period 2021-2030

Governmental institutions

Key institutions and their role in policy making include the following:

Ministry of Environment and Energy - This is the umbrella institution for the implementation of national energy and climate policies in Croatia.

Croatian Energy Regulatory Agency (HERA) - this is an autonomous, independent and non-profit public institution, which regulates energy activities in the Republic of Croatia. HERA's obligations, authorities and responsibilities are based on the Act on the Regulation of Energy Activities, the Energy Act and other acts regulating specific energy activities. Its role is to regulate energy activities and is responsible for the improvement and implementation of by-laws, issuing licenses, setting tariffs, certifying the eligible producer status, etc.

Croatian Energy Market Operator (HROTE) - It performs the public service of organizing the electricity and gas market and analyses and proposes measures for its improvement. It also undertakes tasks related to the various incentives required for electricity production from renewable energy sources and cogeneration, which involves collecting compensation from suppliers and calculating and allocating funds on the basis of concluded contracts with eligible producers entitled to an incentive price or support scheme.

The Croatian Hydrocarbon Agency provides operational support to competent bodies involved in hydrocarbon exploration and exploitation, geothermal energy, underground storage of natural gas, as well as the permanent disposal of gases in geological structures and activities for ensuring compulsory stocks of oil and petroleum products.

Ministry of Construction and Physical Planning - It is responsible for creating policies and measures to achieve the set energy savings targets in buildings. Prepares laws and regulations, strategies and programmes in connection to long-term integral renovation of buildings: family houses, apartment buildings, commercial non-residential buildings and public sector buildings.

Environmental Protection and Energy Efficiency Fund (EPEEF)- This is responsible for co-financing the measures defined in the national energy and climate plans, and acts as an intermediate body level 2 for the use of ESI funds under the Operational Programme Competitiveness and Cohesion 2014 - 2020, in parts relevant to energy and climate. The EPEEF also allocates the funds collected from emissions through auctions in the EU market, according to the Plan for the use of funds acquired from the sale of emission allowances through auctions in the Republic of Croatia for the period from 2017 to 2020 (OG No. 19/18).

The EPEEF also manages the funds paid by energy suppliers in the event of failure to fulfil their obligations under Article 13 of the Energy Efficiency Act and is obliged to invest them in alternative measures.

Energy Demand and Supply

The total primary energy supply (TPES) in Croatia in 2018 totalled 9,769 ktoe. In the period from 2013 till 2018, the total primary energy supply decreased at an average annual rate of 0.3%. In this period, there was a decrease in the consumption of coal and coke and hydropower, whereas the share of consumption of other energy forms increased. In 2018, the total primary energy supply in Croatia decreased by 1.2% as compared to the previous year.

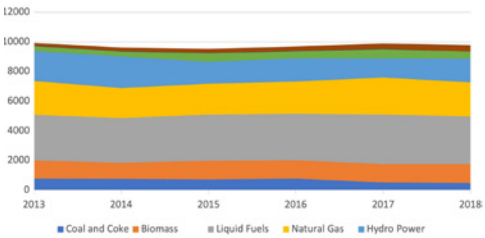
Hydropower increased by 24.5% due to favourable hydrological conditions. As a result of these conditions consumption of imported electricity dropped by 22.5% and natural gas decreased by 7.9%. Liquid fuels had the highest share in the total consumption of the country in 2018 at 32.9%, followed by natural gas at 23.6%, hydro at 20.5%, fuel wood at 12,5%, coal and coke at 7.8%, and other energy sources having smaller shares. Croatia's energy mix between 2013 and 2018 is shown in Table 5.76.

Table 5.76 **Total primary energy supply (ktoe)**

	2013	2014	2015	2016	2017	2018
Coal and Coke	769	755	713	768	517	486
Biomass	1,234	1,102	1,258	1,253	1,244	1,271
Liquid Fuels	3,066	3,005	3,127	3,124	3,340	3,213
Natural Gas	2,282	2,021	2,082	2,175	2,500	2,303
Hydro Power	2,028	2,125	1,472	1,568	1,285	1,600
Electricity	333	340	584	476	598	463
Heat	15	12	15	16	16	15
Renewables	186	251	270	308	385	414
TOTAL	9,913	9,611	9,521	9,688	9,885	9,765

Source:EIHP

Figure 5.54 **Total primary energy supply (ktoe)**



Source EIHP

In 2018, Croatia's primary energy production reached 5,284 ktoe. In the same year, hydro power had the largest share of 30.3% in the total primary production followed by fuel wood with a 28.5% share, natural gas with 19.5%, crude oil with 14.1% and renewables with 7.3% (solar and wind).

During 2013-2018, primary energy production decreased at an average annual rate of 1.9 percent. Noteworthy decreasing trends are recorded in the production of natural gas (7.4% long-term annual decrease) and hydropower (4.6% long-term annual decrease). Production of other primary forms of energy increased.

In 2018, Croatia imported 7,590 ktoe and exported 3,005 ktoe of primary energy sources. The largest share of 67.1% corresponded to crude oil imports and petroleum products, which were followed by natural gas at 17.3% and electricity at 17.3%. The share of coal and coke in total primary energy import was 6.2%.

At the same time, Croatia exported 3,005 ktoe of primary energy. The largest share, which amounted to 81.48%, was attributed to petroleum products, while biomass contributed with a share of 9.2% and electricity with a 5.8% share.

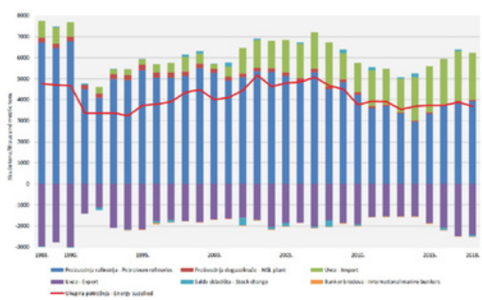
The country's energy dependency for 2018 amounted to 45.9%, which represents a decrease of 1.2% compared to the previous year.

The Energy Market

Oil and Petroleum Products

The total consumption of liquid fuels in 2018 amounted 3,213 ktoe, which was the highest share of all primary products in Croatia (32.9%). In terms of final energy consumption, the share of liquid fuels was even larger and amounted to 40.7% in 2018. Croatia produced 732.1 thousand tons of liquid fuels, which was about 20% of the country's liquid fuels needs. Total reserves of oil and condensate amounted from 6,998.1 thousand m^3 for P1 to 10,009.8 thousand m^3 for 3P.

Figure 5.55 **Petroleum products supply in the Republic of Croatia**



Source EIHP

Upstream Activities

Crude oil is produced from 38 oil fields and gas condensate products from 9 gas fields. Exploration and production of oil has a long history in Croatia that dates back to the 1850s, when the first well was drilled near seeps. Geophysical surveying techniques were also applied at an early date. Peklenica was the first well drilled in 1884 where oil was exploited through shallow mineshafts until the first well was drilled. In the period after the end of the Second World War till 1950, oil and gas exploitation at shallow depths continued.

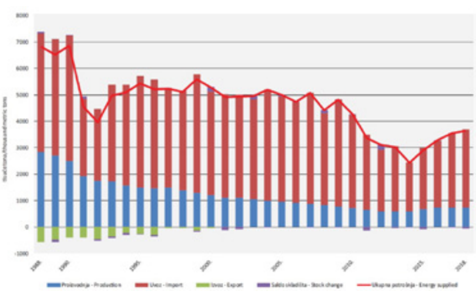
During the 1960s, some 20 discoveries were made out of at least 170 New Wildcat Field (NFWs) drilled. During the 1970s, about 180 NFWs were drilled. They resulted in 19 oil and oil/gas discoveries, and 13 gas fields.

During the 1980s, at least 124 exploratory wells were drilled. Of that number, 22 wells were commercially successful, pointing out the increased maturity of the area from an exploration perspective. During the 1990s, at least 62 new exploratory wells were drilled, and 10 of those wells were ascribed as commercially viable. Seven wells were drilled from 2000 to 2008, which resulted in three gas and gas/ condensate discoveries.

In the period from 1952 until now Croatia discovered and put into commercial operation 45 oil and 30 gas fields. From these fields, 106 million tons of oil, about 9 million tons of condensate and 74 billion m^3 of natural gas have been produced until today. The maximum annual amount of oil produced in Croatia was recorded in 1981, and amounted to 3,140,777 tons. At the same time, the largest quantity of natural gas production was 2,176,657,000 m^3, which was achieved in 1989. The largest oil fields in Croatia are the following: Beničanci, Stružec, Jaundice, Šandrovac, Ivanic, Lipovljani, Jamarice, Đeletovci, Jagnjedovac and Bilogora, while large gas fields include: Molve, Boksic, Kalinovac, StariGradac and Okoli.

In total, more than 550 oil and gas wells have been developed onshore and offshore in Croatia over the last 70 years.

Figure 5.56 **Crude oil supply in the Republic of Croatia**



Source EIHP

Today the **Croatian Hydrocarbon Agency** is monitoring exploration and exploitation of hydrocarbons in the Republic of Croatia. Furthermore, the Agency is responsible for defining exploration activities, for establishing rules and reputations for exploration and exploitation of hydrocarbons and for providing operational support to competent bodies during licensing rounds. In addition, the Agency supervises all hydrocarbon exploration of production activities and is in charge for all licensing rounds.

Over the last years, Croatia has created the necessary legal framework and attracted large investments in exploration and production. At Croatia's 1st Onshore License Round in July 2014, six onshore exploration blocks were offered, covering the areas of Drava, Sava and Eastern Slavonia. Upon closing the License Round, the government of Croatia awarded licences to INA-INDUSTRIJA NAFTE Ltd., a Croatian company, and Canadian company Vermilion. Three years after the signing of the contract, the first onshore licensing round yielded the first results with two companies reporting gas finds.

In 2018, Croatia launched the country's 2nd onshore licensing round offering seven onshore blocks all located in Croatia's prolific Pannonian Basin. This is the second of three planned onshore licensing rounds. The seven exploration blocks offered in this licensing round are located in Croatia's highly prolific Pannonian Basin. The total acreage available is 14,272 km^2. The available blocks range in area from 1,361 to 2,634 km^2.

Croatia's Pannonian Basin is well-known and has a long history of oil and gas producing fields. A large acreage in the basin, remains underexploited with respect to deposits. Preliminary analysis of the seismic and other available data confirm that the available acreage contains significant remaining potential. The licensing round concluded in mid-2019 when the government of Croatia awarded new licenses for the exploration and production of hydrocarbons in six onshore exploration blocks.

Oil Refining and Oil Marketing

Development and production of oil and gas in Croatia has been carried out by **INA-Industrija nafte, d.d.** (INA, d.d.). INA Group had a leading role in Croatian oil business and enjoyed a strong position in the region in oil and gas exploration and production, oil processing, and oil products distribution activities. INA, d.d. is a listed company with the Hungarian MOL Group and the Croatian Government as its biggest shareholders, while a minority of its shares is owned by private and institutional investors. INA Group is comprised of several affiliated companies wholly or partially owned by INA, d.d.. The Group owns and operates three oil rafineries: Oil Refinery Rijeka (Urinj), Oil Refinery Sisak and Lube Refinery Zagreb Ltd.

Rijeka oil refinery (Urinj) is located in the northern part of the Adriatic Sea. It is the shortest and most convenient connection to central Europe and with the Mediterranean. In Rijeka, INA has built a road, railway, marine and pipeline infrastructure for the supply and shipment of products, crude oil and petroleum derivates.

Rijeka oil refinery is connected through an underwater pipeline - 7.2 km long and 20" in diameter - with the port and petroleum terminal in Omišalj, on the island of Krk (owned by JANAF). The capacity of the oil refinery at Rijeka is 4.4 million tons/annum. In 2011, INA started a comprehensive modernization and upgrading plan of the refinery. Thanks to the planned investment in the heavy residue processing project, the modernisation of existing units, a new port with a closed coke storage facility and greater overall complexity, the Rijeka Oil Refinery will become a top European refinery. Investment in the heavy residue processing project amounts to over HRK 4 billion (€530 million), which is the largest single investment project in the history of the INA company.

The Sisak oil refinery is an inland refinery located some 50 kilometres to the south of Zagreb. The capacity of the Sisak Oil Refinery is 2.2 million tons/annum. The refinery development program foresees the concentration of crude oil processing activities in the Republic of Croatia at the Rijeka Oil Refinery and, as part of this, the conversion of the Sisak Oil Refinery into an industrial centre is foreseen. As part of the renovation work attention is given to the development of bio-component processing projects. These are expected to operate profitably and contribute to the positive development of the regulatory environment in the EU and the Republic of Croatia. As part of INA's renovation project a modern logistics centre has been included together with bitumen production, lubricant production and other sustainable and economically viable activities. In 2018, there were about 867 petrol stations in total in Croatia, out of which 388 petrol stations were owned by INA.

Imported crude oil is transported to regional oil refineries by the JANAF oil pipeline system owned and operated by **JADRANSKI NAFTOVOD, Joint Stock Co. (JANAF Plc.)**, headquartered in Zagreb. The JANAF pipeline was constructed in 1979 as an international oil transportation system from the tanker and terminal port of Omišalj to domestic and foreign refineries in Eastern and Mid-Europe. The designed pipeline capacity amounts to 34 million tons of oil a year, and the installed one is 20 million tons. The storage capacity at the Omišalj, Sisak and Virje terminals amounts to 1,940,000 m3 for oil and 222,000 m^3 for oil products in Omišalj and Zagreb.

The JANAF oil pipeline system, consists of a reception and forwarding terminal at Omišalj on the island of Krk. A pipeline system of total length of 631.3 kilometres has been developed, which includes the following branches: Omišalj-Sisak; Sisak-Virje (with a section to Lendava)-Gola (Croatian-Hungarian border); Sisak-Slavonski Brod (with asection to Bosanski Brod)-Sotin (Croatian-Serbianborder),receptionand forwarding terminals in Sisak, Virje and near Slavonski Brod, Omišalj-Urinj submarine pipeline, which connects terminal port of Omišalj on the island of Krk with the INA-Rijeka Oil Refinery on land, the island of Krk-mainland section in the total length of 5.05 km, with the submarine section of 730 meters, as a part of Omišalj-Sisak section.

Map 5.12 **JANAF pipeline system**

Source: JANAF

The inspection, evaluation, rehabilitation, upgrading and reconstruction of the JANAF oil pipeline project was financed by WBIF and had the objective of preparing a tender dossier in order to replace a section of the oil transportation network between Omisalj to Sisak with an underground/undersea pipeline, and also to conduct a review of the entire Croatian oil network, with a view of identifying potential future investment requirements to rehabilitate and reconstruct the network in Croatia. Reconstruction, upgrading, maintenance and capacity increase of the existing JANAF and Adria pipelines linking the Croatian Omisalj seaport to the Southern Druzhba (Croatia, Hungary, Slovak Republic) aim at increasing capacity, operation and security of oil pipelines from Omisalj (HR) through Hungary to the Southern Druzhba pipeline in Slovakia.

The **Croatian Hydrocarbon Agency** is responsible for maintaining the compulsory stocks of oil and petroleum products of the Republic of Croatia at the level corresponding to 90 days consumption by July 31st, 2012. Croatian Hydrocarbon Agency performs activities and carries out tasks within the scope of activities and competences prescribed by the Act, including all activities necessary for performing tasks stipulated by laws and other decisions, particularly the following:

- Collection of the fee for the compulsory stocks of crude oil and petroleum products.
- Purchase and sale of crude oil and petroleum products for the purpose of forming and replenishing stocks.
- Organization, supervision and management of compulsory stocks of crude oil and petroleum products.
- Spending of funds for designated purposes in order to form and store compulsory stocks of crude oil and petroleum products.
- Determining the conditions for storing compulsory stocks of oil and petroleum products.

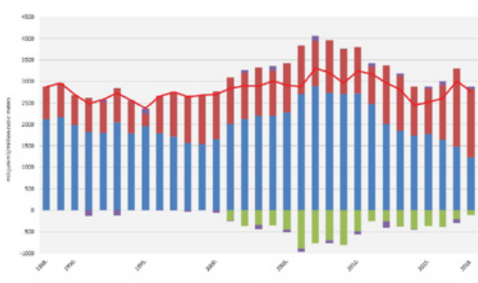
Natural Gas

Croatia's total consumption of natural gas in 2018 amounted to 2.8 bcm, which is the second largest share at 23.6% of primary energy production. Total consumption of natural gas increased from 2013 by 0.2% yearly, with a decrease between 2018/2017 amounting to 7.9%. In terms of final energy consumption, the share of natural gas fuels was much smaller and amounted to 13.0% in 2013 (1 bcm).

In 2018, Croatia produced 1.2 bcm of natural gas, which correspond to about 45% of its natural gas needs. Proven reserves of natural gas amount to 10.3 bcm. Natural gas is produced from 18 on-shore and 3 offshore exploration areas, having a share of 45% of total domestic demand.

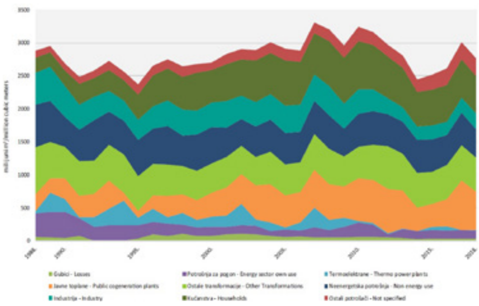
In 2018, 1.6 bcm of natural gas was imported from various countries. All imported natural gas was acquired in the open gas market. Croatia does not have any government supported long-term import contracts.

Figure 5.57 **Natural gas supply in the Republic of Croatia**



Source EIHP

Figure 5.58 **Natural gas consumption in the Republic of Croatia**



Source EIHP

Transportation of natural gas is a regulated energy activity performed as a public service. The energy entity Plinacro d.o.o. is the transport system operator of the Republic of Croatia and is owned by the Republic of Croatia. Plinacro d.o.o. manages the network of the main gas and regional gas pipelines through which natural gas from domestic production (in the northern part of continental Croatia and the Northern Adriatic) and from imports via Slovenia (Rogatec-Zabok) and Hungary (Donji Miholjac-Dravaszerdahely) is transmitted, to exit measuring-reduction stations where gas is delivered to gas distribution systems and to end (industrial) customers directly connected to the transport system.

The total length of the gas transport system in the Republic of Croatia at the end of 2019 was 2,531 km, of which 952 km were main gas pipelines under a working pressure of 75 bars, and 1,579 km of branch gas pipelines under a working pressure of 50 bars.

The gas is received into the transport system from nine connection points at entry measuring stations. Six of which serve for receiving gas from production fields on Croatian territory, two connection points are international connection points and serve for receiving gas from import routes, while one is for withdrawing gas from the Okoli underground gas storage facility (UGS Okoli). Gas is delivered to transmission system users through 157 exit measuring-reduction stations.

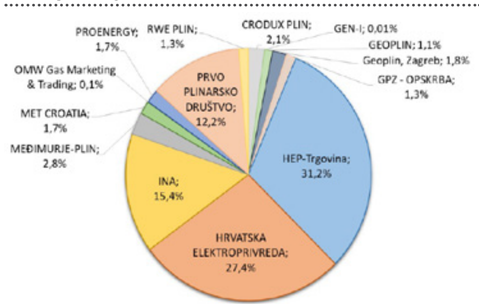
The **underground gas storage** at Okoli is managed by the Podzemno skladište plina, Ltd. company, which is owned by PLINACRO. The designed capacity of the underground gas storage is 5 050 GWh. Maximum injection capacity is 200 MWh/h and the maximum withdrawal capacity is 300 MWh/h.

Gas distribution is a regulated energy activity performed as a public service. In 2018, gas distribution in the Republic of Croatia was performed by 35 energy entities.

According to the Croatian Gas Association total distributed gas quantities in the Republic of Croatia in 2018 amounted to 1.2 bcm. 0.6 bcm were distributed to households and 0.6bcm to users of the commercial sector. In 2018, the total number of distribution system users amounted to 671,740. In 2018 there were 626,307 households' customers, and 45,433 commercial users. The total length of all gas distribution systems in the Republic of Croatia at the end of 2018 amounted to 18,067 km.

In 2018, 49 gas suppliers grouped into 14 balancing groups, used the gas transmission service. Head of the balance groups is HEP Trade d.o.o. which absorbed 31.2% of the gas from the transportation system. Other balance groups included HEP Trgovina d.d. with 27.4% gas volume, the INA balance group d.d. with 15.4%, the balance group Prvo plinarsko društvo d.o.o. with 12.2% of gas, while the remaining 10 balance groups were responsible for 13.8% of gas.

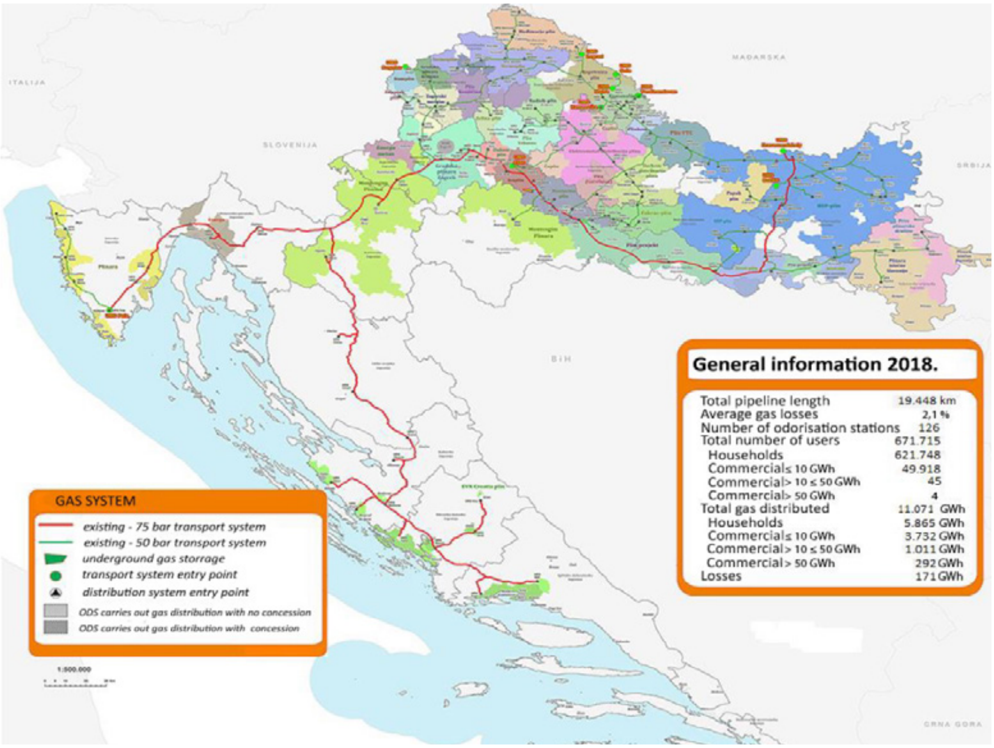
Figure 5.59 **The shares of balancing groups in the total natural gas quantities delivered from the transport system in 2018**



Source EIHP

5

Map 5.13 **Gas system in republic of Croatia in 2018**



Source: HERA

Major **planned new projects** are related to gas exploration (described in the oil section), development of an LNG terminal, the expansion of the gas transmission network and development of a new underground gas storage facility.

LNG Croatia LLC is a company established for the purpose of building and operating the infrastructure necessary for receiving, storing and regasifying liquid natural gas. In accordance with planned deadlines for the construction of the floating LNG terminal on the Island of Krk, a Final Investment Decision was taken on 31 January 2019.

The procurement procedure of the floating, storage, and regasification unit (FSRU vessel) was carried out in November 2018. The bid from company Golar was evaluated as the most economically viable, which offered a conversion of an existing LNG tanker to the FSRU vessel worth €159.6 million. It is an LNG carrier, which was built in 2005 and sails under the name "Golar Viking.

All activities related to the commissioning of the terminal begun on 2 of December 2020: the testing of certain systems of the FSRU vessel and the testing of the onshore facilities. Commercial operations at the terminal started on 1 January 2021, after the successful commissioning of the FSRU and overall LNG terminal infrastructure activities in December 2020.

In accordance with the conducted procurement procedures the total capital expenditure of the project was reduced to €233.6 million (the initial planned investment amounted to €383 million). In addition to an already approved grant from the European Commission in the amount of €101.4 million, the government of the Republic of Croatia has made a decision on financing the first phase of the project for the floating LNG terminal on the Island of Krk with which a grant of the order of €100 million was provided. The remaining part of the required capital expenditure in the amount of €32.2 million will be provided by the shareholders of LNG Croatia LLC through an increase of equity.

At 15th June 2020, LNG Croatia LLC finished the long-term binding process for booking the capacity of the LNG terminal. All free terminal capacity has been booked for the next 3 years and that there is no more available capacity. Plinacro Gas Transmission System Operator completed the development of the main Croatian gas system.

Future system development is related to regional interconnection pipelines (IAP, neighbouring countries connections) and transmission of gas from the Krk LNG terminal. Most of the pipelines, which are in the focus of future development plans, are nominated as EU PCI projects and Energy Community Projects of Mutual Interest - PMI.

Map 5.14 **Plinacro PCI projects**

Source: Plinacro

Plinacro PCI list projects

1. Zlobin-Omišalj LNG evacuation pipelines and compressor station KS1
2. Croatia Slovenia interconestion (Lučko-Zabok-Rogatec (SLO)) compressor stations KS2 and KS3

Map 5.15 **Plinacro PMI projects**

Source: Plinacro

Plinacro PMI list projects
1. Ionian Adriatic pipeline
2. Croatia - Bosnia and Herzegovina interconnection (Zagvozd - Imotski - Posušje)
3. Croatia - Bosnia and Herzegovina interconnection (Rakovica - Tržac - Bihać)
4. Croatia - Bosnia and Herzegovina interconnection (Slobodnica - Brod - Zenica)
5. Croatia - Serbia interconnection (Slobodnica - Sotin - Bačko Novo Selo)

PSP d.o.o. underground gas storage operator intends to develop peak storage facility at Grubisno Polje. Peak storage facility Grubisno Polje project development will consist of two phases:

- **Phase I** will be the extraction of gas from the gas reservoir/gas field Grubisno polje. Facilities and installations will be built for gas treatment (natural gas plant), supervision system and process management, connecting pipelines to the wells, connecting pipelines to the main pipeline Virovotica-Kutina, access roads, water system etc.

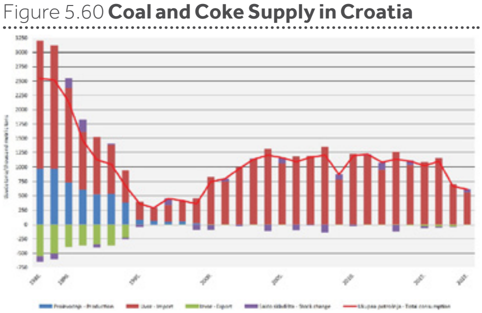
- **Phase II** concerns the development of the underground gas storage in the partially depleted gas reservoir of Grubisno polje. Working volume of new UGS will be a minimal 25 million m^3, with a maximum level of injection capacity up to 1.4 million m^3/per day and maximum level of withdrawal capacity from 1.7 to 2.4 million m^3/per day with a possibility of multiple injection and withdrawal circles during winter season. The primary task of this underground gas storage would be to ensure peak withdrawal capacities during winter season, or more precisely as a support during withdrawal of gas from the seasonal gas storage in UGS Okoli.

Solid Fuels

Total consumption of solid fuels (coal and coke) in 2018 amounted to 615.2 thousand metric tons, which is the fifth largest share of all primary products in Croatia (share of 5.0%). The total consumption of solid fuels has been decreased steadily from 2013 onwards by 11.6% yearly. In the period 2017-2018, consumption of solid fuels decreased further by 7.5%. Most of the coal is consumed in the energy transformation sector for power generation. In terms of final energy consumption, the share of solid fuels is much smaller and amounted to 3.0% in 2018. Some 95.0 thousand metric tons was used in the industrial sector, mainly by the cement industry.

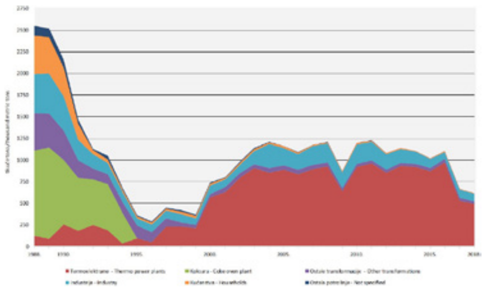
Proven coal reserves in Croatia amount to 45,149 thousand metric tons, but currently there is no coal production in Croatia. Total coal consumed in the Republic of Croatia is provided by imports. Brown coal and lignite are mostly imported from Bosnia and Herzegovina, the Czech Republic and Hungary. Coke is mainly imported from the neighbouring countries (Hungary, Italy, Poland and Czech Republic), while hard coal is procured at the international market and comes from the major coal exporting countries (In 2018 Russian Federation, USA and Columbia).

Figure 5.60 **Coal and Coke Supply in Croatia**



Source EIHP

Figure 5.61 **Coal and coke consumption in the Republic of Croatia**



Source EIHP

There are no plans for the revitalisation of old or the development of new coal or coke production facilities.

Electricity

Total consumption of electricity increased from 2013 by 1.5% yearly, with 2018/2017 increase amounting to 0.4%, reaching 17.2 TWh in 2018. In the final energy consumption in 2013 the share of electricity amounted to 20.3% (16.1 TWh). The installed electricity generating capacities in the Republic of Croatia include hydro and thermal power plants, owned by the HEP Group, an increasing number of wind power plants and other power plants using renewable energy sources and certain number of industrial power plants.

By the end of 2018 electricity generation capacities in Croatia encompassed 17 locations with hydro power plants, 7 locations with thermal power plants, one half of the installed capacities of the nuclear power plant Krško (located in the territory of Slovenia) and a large number of RES power plants. Thermal power plants are gas-fired, coal-fired and liquid fuel fired (only industrial plants). The total installed capacity of all power plants in the Republic of Croatia by the end of 2018 amounted to 5,000.4 MW. Out of this amount, 2,152 MW corresponded to thermal power plants, 2,199.5 MW to hydro power plants, 586.3 MW to wind farms and 67.7 MW to solar power plants. There is also 348 MW in the nuclear plant at Krško (50% of total available capacity) used by the Croatian power system. The total installed capacity of Krško NPP is 696 MW.

Table 5.77 **Electricity generation capacity in the Republic of Croatia (HEP Group ownership) in 2019**

Electricity generation capacity	Available power (MW)	Electricity produced in 2018
Hydro power plants (HPP)	2,199.5	7,784.9
Thermal power plants (TPP)	2,152.0	4,453.4
Wind power plants	586.3	1,335.4
Solar power plants	67.7	74.9
TOTAL	5,005.4	13,631.7

Source: EIHP

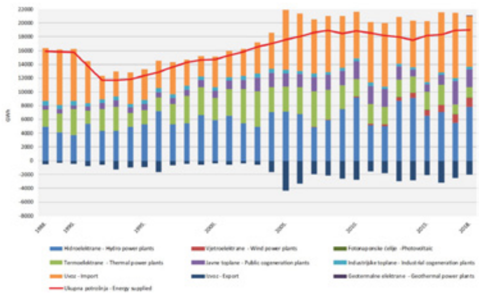
Industrial power plants include units within the industrial installations, which are connected to the electricity grid. Industrial power plants generate electricity/heat/mechanical energy for own use in industrial processes, while the electricity surplus can be sold to the transmission/distribution grid. These power plants are not a part of the HEP Group, but they have purchase agreements and can deliver the power they produce directly into the power system. Total installed capacity of industrial power plants amounted to about 150 MW in 2019.Most power plants that use renewable energy sources have the status of preferential electricity producers. In addition to securing the right of priority in the delivery of electricity to the electricity system, the status of preferential electricity producer was one of the conditions for obtaining incentives under tariff systems for the production of electricity from renewable energy sources and cogeneration.

Table 5.78 **Preferential electricity producers in 2018**

Plant type /primary energy source	Number of Plants	Installed Capacity (MW)	Electricity produced (GWh)
Solar	1229	52.43	69.2
Hydro	13	5.79	24.6
Wind	21	555.80	1,345.5
Biomass	28	58.33	291.9
Geothermal	0	0.00	0.00
Biogas	37	40.73	316.4
Landfill and wastewater treatment plants gas	1	2.50	0.1
Cogeneration	6	113.29	434.8
TOTAL	1,335	828.87	2,482.5

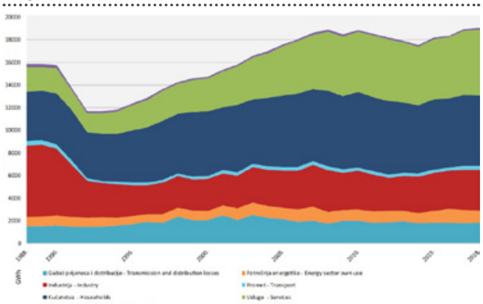
Source: EIHP

Figure 5.62 **Electricity supply in the Republic of Croatia (in GWh)**



Source EIHP

Figure 5.63 **Electricity consumption in the Republic of Croatia (in GWh)**



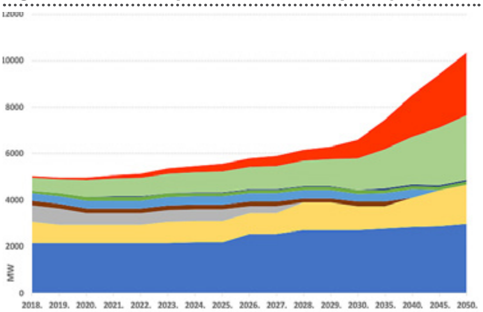
Source EIHP

According to the Energy Sector Strategy, it is envisaged that the total installed electricity capacity will increase from 5.05 GW in 2017 to 6.57 GW in 2030. On average, around 170 MW of new power plants per year are required to be built. The anticipated growth in the construction of RES power plants is significant. It is expected that from the initial 519 MW in 2017, the capacity of WPPs will increase to around 1,360 MW in 2030, and about 2,700 MW by 2050. On average, over the thirty-year period, 80 MW of new WPPs should be built annually, which is more than the historical average achieved of about 50 MW per year.

By 2030, about 770 MW of new photovoltaic projects are expected to be connected to the grid. About 470 MW relates to integrated photovoltaic projects, while about 300 MW should be built equally on the distribution and transmission network. By 2050, the total power of photovoltaic power plants would reach about 2,700 MW.

The end result and the structure of production capacities after 2040 is significantly influenced by the assumption that the Krško NPP license will be extended. If there is no license renewal, this production needs to be replaced by new sources (practically wind and solar). In other words, the conservative variant was assumed where it was necessary to invest in new low carbon projects. Sensitivity analyses show that a nuclear option would be competitive in the event that smaller generation units with lower construction costs become available in the market, compared to today's costs for large nuclear power plant projects in Europe. In this regard, it is necessary to monitor the development of new technologies in the forthcoming period, to analyse the competitiveness of the nuclear option and the development of announced projects in the region (eg. Slovenia, Hungary). In addition, the requirement for complete decarbonisation of all sectors could encourage greater use of nuclear energy given the potential for other applications (eg. cogeneration and hydrogen production).

Figure 5.64 **Power plant installed capacity by 2050**



Source: Energy sector strategy

According to the HOPS d.o.o. Croatian Transmission System Operator ten-year network development plan for 2020-2029, in the next three-year period a new power plant (EL-TO Zagreb, block L) is planned, with a capacity of 150 MW, for whose connection an appropriate connection contract has been concluded. Also, it has been agreed to increase the connection capacity of the existing HPP Varaždin after its planned renovation at 110 MW.

Table 5.79 **Planned power plants for connection to the transmission network with connection contracts signed**

Power plant name	Anticipated connection power [MW]	Estimated year of connection
EL-TO Zagreb blok L	150	2021
HE Varaždin	+16	2022
TOTAL	166	

Source: HOPS d.o.o.

New power plants which are in the process of licencing prior to the conclusion of the Connection Agreements are shown in Table 5.80.

Table 5.80 **Planned power plants to be connected to the transmission network**

Power plant name	Anticipated connection power [MW]	Estimated year of connection
GTE Zagocha	20	2022
GTE Legrad	19.9	2025
TOTAL	39.9	

Source: HOPS d.o.o.

New power plants that have requested a connection to the transmission network and have been issued preliminary energy consent, but have not yet been requested to conclude a connection agreement, are shown in the Table 5.81

Table 5.81 **Planned power plants for the connection to the transmission network - with preliminary energy consent**

Power plant name	Anticipated connection power [MW]	Estimated year of connection
RHE Vrdovo	540/-490	medium term
RHE Korita	600/-500	medium term
HE Senj 2	380	medium term
HE Kosinj	33.7	medium term
TOTAL	1,553.7 MW/-990 MW	

Source: HOPS d.o.o.

In recent years, HOPS has received a large number of requests for the connection of new wind farms with a total capacity exceeding 2,000 MW. The size of WPP projects in the Republic of Croatia varies between 18 MW and 156 MW, and most are considered for connection to the 110 kV grid. In assessing the connection of planned hydroelectric power plants, two basic categories are distinguished:

- WPPs which have a Contract for connection to the transmission or distribution network - connection planned in the next three-year period,
- other WPPs (in different development stages but without connection contract) - connection planned for the next 10-year period.

It should be emphasized that the plans for connection of wind power plants presented here do not represent the final state of their construction and connection to the transmission network, since they depend on investor plans, on how the projects will be further developed.

Table 5.82 **Planned WPPs for the connection to the transmission network in 2020-2022 with connection contracts signed**

Power plant name	Anticipated connection power[MW]
Zelengrad - Obrovac	12
Krš - Pađene	142
ST 3-1/2 Visoka Zelovo	33
Bruvno	45
Konavoska brda	120
ZD2P	48
ZD3P	33
Senj	156
Korlat	58
Opor	33
Boraja	45
TOTAL	725 MW

Source: HOPS d.o.o.

It should be mentioned that 15 additional WPPs projects are in different phases of project preparation with total anticipated capacity of 835.5 MW. By the end of the planned ten-year period, a total of 2,218.45 MW of wind power plants should be connected to the transmission network (provided that all of the mentioned WPP projects are completed). At the end of 2017, 2018 and throughout 2019, a considerable number of requests for connection of solar power plants to the transmission power network of the Republic of Croatia, with a total power exceeding 600 MW, were received by HOPS. The estimated power of individual power plants ranges from 17 MW to 150 MW.

Table 5.83 **Planned solar power plants for connection to the transmission network**

Power plant name	Anticipated connection power [MW]	Estimated year of connection
SE Benkovac	60	2024
SE Karin	30	2024
SE Kruševo	17	2022
SE Sukošan	45	2022
SE Kolarina	38	2024
SE Raštević	41	2024
SE Korlat	75	2022
SE Konačnik	35	2022
TOTAL	341 MW	

Source: HOPS d.o.o.

Five additional solar power plant projects are in different phases of project preparation with a total anticipated capacity of 410 MW.

Electricity transmission and distribution are regulated activities performed as public services. There is a single transmission system operator in the Republic of Croatia, Hrvatski operator prijenosnog sustava d.o.o. (Croatian Transmission System Operator Ltd) (hereinafter: HOPS), which is responsible for the security and reliability of the operation of the electric power system and the proper co-ordination for the operation of the production, transmission and distribution system. The transmission network and production facilities, for which operation HOPS is responsible for, are shown in Map 5.16.

Map 5.16 **The transmission network and production facilities of the Croatian electric power system (2018)**

Source: Croatian Transmission System Operator Ltd. (HOPS d.o.o.)

The total length of electricity transmission lines in 2018 amounted to 7,802 km (1,247 km - 400 kV lines, 1,246 km - 220 kV lines, 5,309 km - 110 kV and medium voltage). A total of 183 transformer stations were to be found in the transmission system.

The total length of distribution system lines in 2018 amounted 103,327 km (10 km - 110 kV lines, 4,488 km - 35(30) kV lines, 9,738 km - 20 kV lines, 27,505 km - 10 kV lines, 61,586 km -0,4 kV lines and additional 31,527.4 km are for household connections). There was a total of 27,416 transformer stations to be found in the distribution system.

The method used for determining the costs of the transmission system operator in the Tariff system for electricity transmission, without tariff item amounts (Official Gazette, Nos. 104/15 and 84/16) and the distribution system operator in the Tariff system for electricity distribution (Official Gazette, Nos. 104/15), adopted by HERA in September 2015, is the method of approved expenses. The methodology is based on the following principles and rules:

- total costs must be justified, and must be impartial and transparent,
- the tariff items for each tariff model throughout the Republic of Croatia are the same,
- the amounts of tariff items for each tariff model shall be determined in such a way as to correspond as closely as possible to the total costs incurred by the system operator for that tariff model,
- calculation of electricity consumption and peak power is made for each metering point,
- financing for the network development is provided from the revenues and fees for connection to the network and for increasing the connection power, paid by customers and manufacturers
- the tariff for excess reactive energy is the same for all voltage levels,
- the ratio of the higher daily tariff item (HT) to the lower daily tariff item (LT) for the electricity taken over for two-tariff customer categories is approximately 2: 1.

One of the important factors and preconditions for applying this method is the investment plan for transmission and distribution network development in the upcoming regulatory period.

The following tables show the average prices for electric power transmission and electric power distribution for the period 2014 - 2018 by end customer category. The amounts of the average prices of electricity are determined according to the realised income by end customer category, obtained by applying the appropriate tariff items from the tariff systems for electric power transmission and electric power distribution and realised electricity consumption.

Table 5.84 **The realised average price for electric power transmission in the period 2014 - 2018 (lp/kWh)**

Power					
End customer category	**Average price for transmission**				
Commercial - high voltage customers	7.0	7.1	6.6	6.7	7.2
Commercial - medium voltage customers	7.9	7.8	7.7	7.6	7.6
Commercial - low voltage customers	8.9	8.9	8.9	8.9	9.0
Househodls (low voltage customers)	8.9	8.9	8.9	8.9	8.9
Average for all customers	8.5	8.5	8.5	8.4	8.5

Source: HERA

Table 5.85 **The realised average price for electric power distribution in the period 2014 - 2018 (lp/kWh)**

Power					
End customer category	**Average price for transmission**				
Commercial - high voltage customers	-	-	-	-	-
Commercial - medium voltage customers	14.0	13.9	13.7	13.7	13.7
Commercial - low voltage customers	26.3	26.3	26.5	26.7	26.8
Househodls (low voltage customers)	24.6	24.4	24.5	24.5	24.6
Average for all customers	22.5	22.3	22.4	22.2	22.2

Source: HERA

The Croatian Transmission System Operator Ltd. ten-year network development plan 2020 – 2029 provides details of all investments in the Croatian transmission network in the framework of regional and European integration. The Development Plan is in full compliance with the ENTSO-E TYNDP 2018 (Ten Year Network Development Plan) proposal, as HOPS is a full member of ENTSO-E.

The following projects are nominated for the ENTSO-E TYNDP 2020:

- Upgrading of existing 220 kV lines between HR and BA to 400 kV lines - 2032-2033
  - Upgrading of existing 220 kV line between SS Dakovo (HR) and TPP Tuzla (BA) to 400 kV line
  - Upgrading of existing 220 kV line between SS Dakovo (HR) and Gradacac (BA) to 400 kV line
  - Upgrading existing 220 kV SS Dakovo to 400 kV
  - New double 400 kV line between SS Dakovo and location Razbojiste
  - Upgrading of existing 220 kV line between SS Gradacac (BA) and TPP Tuzla (BA) to 400 kV line
  - Upgrading existing 220 kV SS Gradacac (BA) to 400 kV
- New 400 kV interconnection line between Serbia and Croatia - 2035
  - New 400 kV overhead line Sombor (RS) - Ernestinovo (HR)
- Slovenia-Hungary/Croatia interconnection - 2021
  - Double 400 kV OHL Cirkovce(SI)-Heviz(HU)/ Zerjavinec(HR)
- CSE1 New - 2029-2030
  - New OHL 400 kV Banja Luka - Lika
  - New OHL 400 kV Lika - Melina
  - New OHL 400 kV Lika - Konjsko
  - New Substation 400/110 kV Lika
- Croatian south connection - 2035
  - New 400 kV substation interpolated in existing 400 kV line Konjsko - Mostar
  - New 400 kV substation for connetion of new generation and increase of security of supply in the southern area near city of Ploce
  - Double 400 kV line connecting SS ZONE 5 and ZONE 6
  - Double 220 kV line connecting SS ZONE 6 and SS Plat
  - Construction of two addiotional OHL bays for connection of OHL 220 kV ZONE 6 - Plat

In accordance with the procedure and as foreseen by European regulations and the European Commission the following Croatian projects are on the fourth PCI list:

- 3.9.1 Interconnection between Žerjavenec (HR)/ Hévíz (HU) and Cirkovce (SI)

Renewables

Total consumption of renewables in 2018 amounted to 414 ktoe (share of 4%). The total consumption of renewables increased from 2013 by 17.3% yearly, with 2017-2018 increase amounting to 7.5%. If biomass and large hydro power are included in the renewables, then the total consumption of renewable energy sources (RES) rises to 3,284 ktoe (with a share of 34%), which position RES to the first place in total primary energy supply mix in 2018 (consumption of liquid fuels is slightly smaller).

However, the share of renewables in the final energy consumption is much smaller amounting just to 0.3% (21.5 ktoe). Consumption of renewables in the final energy consumption increased from 2013 by 7.4% yearly, with the 2017-2018 increase amounting to 2.3%. If biomass is calculated together with the other renewables, then the consumption of RES in the final energy consumption is 1,146 ktoe, which increases the share of renewables in 2018 to 17%. Croatia's energy policy is set in an Energy Act where a basis for the utilisation of renewable energy is mentioned. The objectives for 2020 are set in the Energy Strategy, which was adopted in 2009 and in the national action plan for renewable energy sources, which adopted in 2013. The production of electricity from RES is promoted through a feed-in tariff and loans system. The Croatian Bank for Development and Reconstruction and the Fund for Environmental Protection and Energy Efficiency operate a loan scheme for RES-E projects.

In October 2013, the Croatian government adopted a national action plan for RES until 2020 which shifts the focus from encouraging wind farm construction to energy production from biomass, biogas, cogeneration plants and small hydroelectric power plants (SHPP), reducing the total incentive costs. The plan is in line with the European Union directive on renewable sources, which contains measures through which member countries must ensure 20% of renewables in energy consumption by 2020. To meet the EU goal, the government wants to encourage SHPP, biomass and biogas because these projects have the biggest impact on the economy. The National Action Plan for the production of energy from RES defined targets for three sectors: electricity sector, transport sector and the heating and cooling sector.

Pursuant to the revised programme, the new shares for 2020 have been calculated as follows:
- 39.0% share of RES in gross final consumption of electricity;
- 10.0% share of RES in gross final energy consumption in transport;
- 19.6% share of RES in gross final energy consumption in heating and cooling.

The main national support measures, in the form of economic and financial mechanisms to promote the use of renewables, are:
- Guaranteed purchase prices (feed-in tariffs) for the generation of electricity from renewable energy sources.
- Promotion of biofuel production.
- Promotion of the use of RES and energy efficiency using funds provided by the Environment Protection and Energy Efficiency Fund (EPEEF).
- Promotion of the use of renewables and energy efficiency through the Croatian Bank for Reconstruction and Development (CBRD).

In 2015, the act on RES and efficient cogeneration was adopted by the Parliament. The purpose of this Act is to promote the production of electricity from renewable energy sources and high-efficiency cogeneration, to promote the production of electricity from renewable energy sources and high-efficiency cogeneration at the point of consumption, to increase the share of total direct energy consumption produced from renewable energy sources by using incentive mechanisms and regulatory framework for the use of renewable energy and high-efficiency cogeneration.

Croatia's Energy Act was revised in 2018

Table 5.86 provides estimated data on installed capacities for heat generation from renewable energy sources (RES-H) and statistical data on installed capacities for electricity generation from RES (RES-E) for 2018.

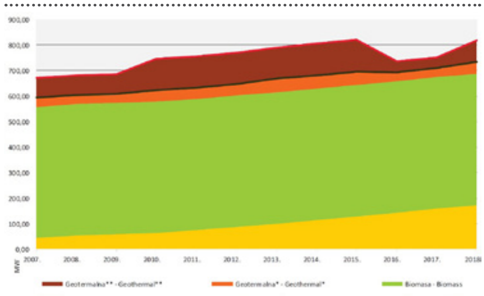
Table 5.86 **Installed capacities for heat and electricity generation from renewable energy sources in Croatia for 2018**

RES	Installed heat capacity (MW)	Installed power capacity (MW)
Solar	172.2	67.7**
Wind	0	586.3
Biomass	515*	64.8
Biogas		50.6
Small hydro power plants	0	38.78
Geothermal	45.6 / 84	10
TOTAL	732.8/816.8	818

* estimation
** systems connected to the grid
Source: EIHP

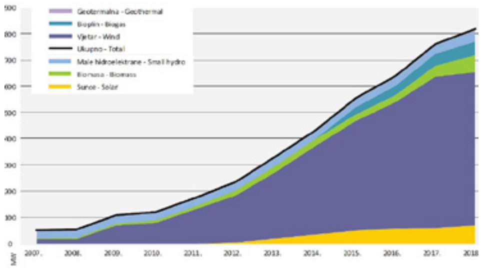
Installed power capacity of photovoltaic systems differs from the value provided by HROTE as it refers to grid-connected systems including autonomous PV systems. Installed capacity of autonomous PV systems that supply facilities without grid connection (lighting houses, holiday houses, GSM bases, parking machines etc.) is estimated at 8.5 MW.

Figure 5.65 **Installed capacities for RES-H generation in Croatia**



* geothermal heat for space heating
** including geothermal heat for hot water and bathing
Source: EIHP

Figure 5.66 **Installed capacities for RES-E generation in Croatia**



Source: EIHP

All existing renewable energy projects and new ones, are registered in the Register of projects and plants for the use of renewable energy sources and cogeneration and of eligible producers (OIEKPP Registry). Registry records data on the project holder, the eligible producer of electricity and the plant, including information on the location and type of facility, technical and technological characteristics and conditions of use depending on the applied technology, basic operating data (installed power plants and planned power generation and heat), and other data derived from preliminary project approvals, the preliminary decision and the decision on the status of eligible electricity producer (location, geodetic points, deadlines, duties, etc.).

Table 5.87 **Overview of registered RES projects entered in the Registry**

Plant category	Number	Installed Electricity capacity [MW]	Thermal capacity [MW]	Contracted subsidised capacity [MW]
Solar power plant	3,782	307.5273	0	53.4
Hydro power plant	49	1676.3490	0	5.9
Wind farm	47	2021.4500	0	585.8
Biomass power plant	119	218.3180	290.4700	73.7
Geothermal power plant	2	20	0	10
Biogas powerplant	64	69.5010	31.8660	42.7
Landfill and wastewater treatment gas power plant	7	9.5990		2.5
Cogenerations	12	1068.9930	180.7800	113.3
TOTAL	4,082	5,392	503	887.3

Source: EIHP

It should be noted that not all solar power projects are registered. Out of 5392 MW of registered renewable electricity capacity, 16% is actually producing and is receiving subsidies from HROTE.

Energy Efficiency and Cogeneration

National targets

The latest energy efficiency targets are summarized in The Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050 and in the Integrated National Energy and Climate Plan for the period 2021-2030.

According to the Energy Development Strategy, increasing energy efficiency is the most important mechanism for reducing energy consumption and one of the fundamental principles of energy transition. Increasing energy efficiency is necessary in order to ensure affordable energy. It is envisaged to increase energy efficiency in all areas of consumption and throughout the production chain from generation, transmission and transport, distribution and consumption. All methods of reducing consumption from legislation, the application of standards and norms, the replacement of plants and devices to the prohibition of using inefficient devices will be applied.

The building sector intends to intensify the application of good practices for energy renovation in all buildings (residential and non-residential) by directing renovation to the nZEB standard (almost zero energy buildings), which also implies stronger utilization of RES (photovoltaic systems, thermal solar collectors, biomass boilers, heat pumps). In the period up to 2030, the transport sector will focus on building new infrastructure for the use of alternative forms of energy in transport (LNG and CNG/CBM, electricity and hydrogen). It is envisaged to increase the share of alternative-powered vehicles, especially electric ones, as well as the electrification of urban and interurban transport, as well as increase the use of LNG in heavy freight, maritime and rail transport. With the development of advanced networks, it is necessary to enable the participation of the transport sector in the cost-effective provision of services of flexibility and balancing of the electricity system. In addition to the development of alternative fuels, activities to stimulate intermodal and integrated transport at national and local levels are also needed.

In addition to sector-specific measures, the development scenario also takes into account the effects of regulatory measures that will have cross-sectoral effects. First and foremost, this refers to the establishment of a functional system of energy efficiency obligations for energy suppliers, in accordance with the current legislative framework of the EU and the Republic of Croatia. It is expected that this mechanism will help achieve major progress in improving energy efficiency in all sectors of direct consumption, through innovative market mechanisms that engage private capital of both suppliers and other players in the energy services market.

It is expected that the transmission losses will stay at the same level in electricity transmission, while it is expected that electricity distribution will further reduce technical losses below the EU average by 2030.

Energy efficiency in the Republic of Croatia is regulated by the following Acts and Codes:

- Energy Efficiency Act (OG Nos. 127/14, 116/18).
- Building Act (OG Nos. 153/13, 20/17, 39/19).
- Act on Protection against Light Pollution (OG No. 14/19).
- By-laws that follow from these Acts.

The national targets for increasing energy efficiency by 2020 are defined in the 3rd National Energy Efficiency Action Plan (NAPEnU) 2014-2016 and revised in the 4th NAPEnU until the end of 2019. The indicative national target for the increase in energy efficiency, expressed as the absolute amount of final energy consumption in 2020 is 6.96 Mten. The corresponding target expressed as the absolute amount of primary energy in 2020 is 10.71 Mten.

Table 5.88 **Indicative national energy efficiency targets in 2030**

Targets 2030	Mten
Primary energy consumption	8.23
Final energy consumption	6.85

Source: Croatia's National Energy and Climate Plan

After 2020, in accordance with the Technical Regulation on Rational Use of Energy and Thermal Insulation in Buildings, all newly constructed buildings should be nearly-zero energy (nZEB). It is expected that the total residential stock will grow at an average rate of approximately 6,600 residential units from 2021 to 2030, 6,300 from 2031 to 2040 and 6,050 units from 2041 to 2050. In order to achieve this growth of the total stock, 10,930,698 m² of new buildings and 8,630,863 m² of renovated buildings are expected in the period from 2021 to 2030 (around 30,000 new and renovated housing units per year, with a very high rate of abandonment and demolition of old poor-quality units of about 11,200 units per year). From 2031 to 2040, the area of newly-built residential buildings will amount to 14,721,602 m², with 9,022,863 m² of renovated residential buildings. This area of renovated buildings per year corresponds to an annual rate of renovation of 1.6%, with a gradual increase from 1% in 2021 to 3% in 2030.

The average final energy consumption in the residential sector will be 30 kWh/m² for newly-built and renovated buildings, and it is expected that there will be no significant variations for the non-residential sector.

It should be noted that, pursuant to Article 2a of Directive 2018/844 amending Directive 2010/31/EU on the energy performance of buildings, the Republic of Croatia will adopt a new long-term strategy for promotion of investments in the renovation of the national building stock, with a plan of measures and indicators for 2030, 2040 and 2050, which will be aligned with the Energy Development Strategy of the Republic of Croatia.

A total of 13.8 million m² of useful heated area of public sector buildings was recorded in the Republic of Croatia in 2010, according to the data from the National Information System for Energy Management. In order to meet the obligation to renovate 3% of the total floor area of heated and/or cooled buildings owned and managed by the central government, in the period until 2020 the Republic of Croatia has chosen an alternative approach, i.e. it has set the target of 117 toe per year in equivalent savings. This approach will also be applied in the period until 2030.

Incentive-based initiatives in the building sector

The key document for the energy efficiency in the building sector is the Long-Term Strategy to Encourage Investment in the Renovation of the National Building Stock of the Republic of Croatia by 2050, which promotes the need to invest in the building stock. The revised strategy aligns the renovation objectives with the NECP in light of demographic trends and activities in the construction sector, with trends of accelerated abandonment of the existing building stock of poorer properties and gradual growth in new construction. The current energy renovation rate of 0.7% per year will gradually rise to 3% over the 2021-2030 period, with a 10-year average rate of 1.6%. An important element is the introduction of additional measurable indicators of energy renovation of buildings, which will strengthen the process of conversion of the stock into nearly zero-energy buildings, i.e. climate neutral.

Energy management and heat preservation is one of the fundamental building requirements. The Technical regulation on the rational use and heat retention of buildings (OG No. 128/15, 70/18, 73/18, 86/18) stipulates the minimum energy performance for new buildings and buildings undergoing major reconstruction, the manner of determining the energy performance of the building, preparation of the study on the use of alternative energy systems, and requirements for nearly zero energy buildings.

Obligation of regular inspections of heating systems and cooling or air conditioning systems in buildings and energy certification of buildings will be put in place by implementing ordinance on energy audit of buildings and energy certification (OG No. 88/17); Ordinance on control of energy certificates of buildings and reports on regular inspection of heating and cooling or air conditioning systems in buildings (OG No. 73/15); Ordinance on persons authorized for energy certification, energy audit of buildings and regular inspection of heating and cooling or air conditioning systems in buildings (OG No. 73/15, 133/15).

Amendments to the Building Act are currently underway in order to address the adoption and implementation of the new Long-Term Strategy of Renovation of the National Building Stock by 2050, promoting electromobility through the installation of infrastructure for charging electric vehicles in buildings and on parking lots adjacent to buildings, simplifying regular controls of heating and cooling or air-conditioning systems in buildings, setting up and supervising technical systems for buildings, defining requirements related to the installation of self-regulation devices, building automation and management systems, as well as changes to the system of issuing authorizations for energy certification of buildings.

It is estimated that in Croatia there are about 50 million m² of useful floor space of apartment buildings, which account for more than 42.3% of total energy consumption. Most of these buildings were built before 1987 and did not have adequate thermal protection and approximately consume 200-250 kWh/m² of heating energy.

In the period from 2014 to 2016, the programme for the promotion of integral renovation of apartment buildings was financed by the funds raised in auctions and implemented through the Environmental Protection and Energy Efficiency Fund; at the end of 2016, the Ministry of Construction and Physical Planning issued a call for applications and allocated HRK 539.23 million (€71.83 million) for energy renovation of 556 buildings; it is estimated that all projects within the framework of this programme will be completed by the end of 2023. A new call for energy renovation of apartment buildings is planned by the end of 2019. Grant funds would be secured from an allocation earmarked for energy renovation of family houses.

In the period from 2014 to 2016, the Programme for Energy Renovation of Family Houses 2014-2020, was financed by national funds raised from auctions through the Environmental Protection and Energy Efficiency Fund; the ERDF funds available under OPCC amount to HRK 200 million (€26 million), but due to complex procedures, these funds are not expected to be utilized for energy renovation of family houses - the plan is to reallocate them for energy renovation of public and apartment buildings, whereas from 2019 onwards this Programme will continue to be co-financed by the funds collected from the sale of emission allowances in auctions, through the Environmental Protection and Energy Efficiency Fund (EPEEF).

In the public sector ERDF (European Regional Development Fund) funds within the OPCC amount to €211 million, are available for energy renovation of public sector buildings, and so far around HRK 1,499 billion have been awarded for energy renovation of 866 buildings; the projects within this programme are expected to be completed by the end of 2023. A FI ESIF energy efficiency loan for public buildings in the amount of HRK 190 million (€25 million) is also foreseen.

Cogeneration: Regulatory framework, installed capacity

There are several large and small cogeneration units operating in Croatia. The most important large cogeneration units are operating in the Zagreb (EL-TO Zagreb and TE-TO Zagreb), Osijek (TE-TO Osijek) and Sisak (TE Sisak) suppling local district heating with heat and simultaneously producing electricity.

Larger industrial cogeneration plants are located in Belišće d.o.o. Belišće, Petrokemija d.d. Kutina, INA Rafinerija nafte Rijeka, at sugar refineries and natural gas processing plants in Croatia.

Indicators of the potential high-efficiency cogeneration and efficient district heating and cooling are taken from the document "Programme for use of efficiency potential in heating and cooling for the period 2016-2030", which was published in November 2015, and which was prepared for the Ministry of Economy (today under the Ministry of Environment and Energy) in accordance with Article 14, paragraph 1 Directive 2012/27/EC.

The established overall (theoretical) potential for high-efficiency cogeneration plants in the Republic of Croatia is estimated with the help of two scenarios concerning the shares of future consumers of DHS coupled with high-efficiency cogeneration: conservative and optimistic. Scenarios are based on the share of consumers of district heating systems that are assumed, based on the determined existing trends (conservative scenario), or optimistic assumptions of positive changes in the economy of the Republic of Croatia (optimistic scenario). Indicators of the potential for use in high-efficiency cogeneration and efficient district heating and cooling are presented in Table 5.89.

Table 5.89 **High-efficiency cogeneration and efficient district heating and cooling Potential**

Indicator	Unit	Conservative scenario, 2030	Optimistic scenario, 2030
Total heat demand (theoretical heat demand for 2030)	ktoe MWh	437 5,086,907	716 8,328,369
Required heating capacity (theoretical)	MWt	3,178	5,262
Share of DHS consumers	%	30.1	55.0
Equivalent heat demand	ktoe MWh	132 1,529,591	397 4,618,222
Equivalent thermal capacity	MWt	956	2,903
Potentially produced electricity	ktoe MWh	207 2,403,643	624 7,257,206

Source: Programme for use of efficiency potential in heating and cooling for the period 2016-2030", Ministry of Economy, November 2015

Cogeneration is regulated by the Act on Renewable Energy Sources and Highly Efficient Cogeneration ("Act") (Croatian Official Gazette nrs. 100/15, 111/18). The use of renewable energy sources and high-efficiency cogeneration is of interest to the Republic of Croatia.

Highly efficient cogeneration in cogeneration plants provides primary energy savings of at least 10%, compared to the reference separate production of electricity and heat. That provides primary energy savings in the case of a cogeneration plant with installed electrical connected load smaller than 1 MW and meets the efficiency and the use of heat according to the new regulation whose contents are defined in Article 25 of the Act.

The main novelties introduced by the new Act related to cogeneration are:

- Changing the model of incentives. Instead of the feed-in tariff system, a new concept of market premium model is introduced.
- The Act stipulates that electricity suppliers are obliged to buy from the operator a certain proportion, expressed as a percentage of the net electricity supplied by eligible electricity producers. The share is determined by the government of the Republic of Croatia by an ordinance which it adopts by 31 October of the current year for the following year. The remaining share of the total net electricity supplied by eligible producers is sold by the operator on the electricity market in a transparent and impartial manner.
- Regulate the status of eligible electricity producer in order to eliminate inconsistencies in the process of issuing, revoking and amending the decision on acquiring the status of eligible electricity producer.
- The obligation of the Ministry to adopt state aid programs for stimulating the production of electricity from renewable energy sources and high-efficiency cogeneration is being regulated in order to adopt programs in accordance with the applicable rules on state aid for environmental protection and energy.
- The system of guarantee of origin for electricity is regulated. The system of incentives is regulated by prescribing the right of appeal to the participants of the tender against the decision of the operator on the selection of the most favorable bidder in the tender for award of market premium and tender for the incentive with guaranteed purchase price, in order to enable the participants of the tender legal protection and control of legality of the competition.
- The issues of collecting and calculating incentive payment funds are regulated in order to prescribe the possibility of raising funds for payment of incentives from the sale of guarantees of origin of electricity produced in the production facility of eligible producers in the incentive system.
- Issues regarding the take-over of electricity from end-users with their own production are regulated in order to prescribe the different values of electricity that the electricity suppliers take from the end-customers with their own production, depending on whether they are the end-customer with their own production from the category enterprise or household.
- The new Act prescribed that government of Republic of Croatia will regulate in detail the issues of classification of production plants, the methodology for determining the share of energy from renewable energy sources in total direct consumption, the status of eligible electricity producer, the system of incentives for the production of electricity from renewable energy sources and the compensation of members of the EQF balance group.

Energy Investment Outlook

The elaboration of the Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050 was preceded by a detailed analysis of all the energy sectors and the necessary investments were identified for each of the sectors which are necessary to achieve the objectives of the strategy. The investment indicators for the adopted S2 scenario are presented below.

Estimation of investment in construction of new power plants (electricity production)

An estimate of the total investment in the construction of new power plants in the period from 2020 to 2050 is presented in Table 5.90.

Table 5.90 **Power plant investments 2020.-2050. (million €)**

Plants type	Investment
Wind	2,297.3
Solar	1,792.1
Heat pumps and electricity in DH	24.9
Storages	219.5
Hydro	1,285.4
Gas	1,026.9
Biomass	247.3
Geothermal	197.8
TOTAL	7,091

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050

The investments shown also include investments in technologies which are not related to power plants, such as large heat pumps for CTS and battery use. Of the total €9.18 billion, or an average of €306 million per year, power plants account for €8.91 billion or around HRK 66 billion (HRK 2.2 billion annually).

The intensity of investments increases towards the end of the period, as emissions need to be reduced more. At the same time, a relatively strong reduction in specific investments in particular technologies, especially PV and WP projects, is assumed. Analysis of the inter-competitiveness of technologies indicates that by 2030 it will be necessary to maintain some support mechanism for the use of cleaner technologies. Current price developments in the emission permits market indicate that certain RES technologies will soon be priced competitively with conventional technologies (at project level). The area where the greatest contribution from the state and regulatory bodies is expected is to create the conditions for the adoption and integration of new technologies into the system, in the technical and commercial / market sense.

Estimation of investments in the electricity transmission network

Preliminary estimates indicate that total investments in the transmission network (including connections to new conventional power plants, wind, solar and other power plants) would amount to HRK 7.9 billion (€1.05 billion) by 2030, assuming equal annual investment, which would mean an investment cost up to HRK 666 million /year (€87 million/year).

In addition to the financial resources needed to cover the costs of building the transmission network, it is also necessary to provide financial resources for balancing the system (through the balancing mechanism and partly through the electricity transmission fee), or for the procurement of a part of the ancillary services of the system (primarily frequency and power regulation), which can be estimated at up to HRK 375 million /year (€50 million/year) on a preliminary basis, based on existing P/f regulatory reserve prices and the energy prices produced in the regulation.

In the period from 2030 to 2050 preliminary estimates indicate that total investments in the transmission network would amount to HRK 9.9 billion (€1.32 billion), assuming equal annual investments, this would mean an investment cost of up to HRK 494 million /year (€66 million/year).

Costs to balance the system (the procurement of a part of the ancillary services of the system), for 2030 to 2050 period, can be roughly estimated at up to HRK 330 million/year (€44 million/year), based on the assumption of reducing the average error of planning for the production of wind power plants to 2% of installed capacity, and the existing prices of P/f regulatory reserves and the prices of energy produced in the regulation.

Estimation of investments in the electricity distribution network

By analysing the current state of the distribution network and the improvements achieved in the previous 20-year period, it is necessary to invest up to HRK 30 billion (€4 billion) in development of the distribution network, i.e. up to HRK 1 billion (€ 0.13 billion) a year will be sufficient during the observed period.

The priorities for investments in the distribution system are as follows:

a. by 2030 - advanced measurement system by 2025 and advanced network pilot projects,
b. by 2040 - advanced network (Phase I: modernization and automation, advanced network control and management features),
c. by 2050 - advanced network (Phase II: integrated adaptive change-optimized distribution system, optimized for resources with active involvement of network users, system capable to prevent crises).

This level of investment presupposes the stimulation of electricity production in the distribution network consumed at the site and coincides with the consumption of electricity ("balancing of production and consumption").

Assessment of investments in district heating systems

Investments in district heating systems in the forthcoming period primarily relate to investments for the replacement of existing heat networks with reduced losses and related investments in control and management systems, both on the part of the network plant and on the part of demand management (end-user). An additional 50 km of networks are assumed to be built by 2050.

Total investments between 2020 and 2050 are expected to amount to HRK 1.8 billion (€240 million).

Assessment of investments in the natural gas system

The development of the gas supply system in the short term relates to the needs of ensuring security of gas supply and meeting the N-1 criteria, ie construction of LNG terminal, interconnections related to LNG terminal, peak UGS Grubišno Polje, potentially development of IAP pipeline and increase of interconnections capacity with Slovenia, and construction 50 and 75 bar pipelines to increase the internal security of gas supply.

In the medium term, development will be based on an increase in the capacity to import and transport gas to neighbouring countries. In the long term, major renovation of the existing 50 bar system will be required. The development of new interconnections with neighbouring countries (BiH, Serbia) will depend on economic viability.

Total investment for the development of short- and medium-term systems is estimated at a minimum of HRK 10 billion (€1.33 billion) and more. This investment will significantly increase if pipelines for significant transit of LNG, Caspian or Eastern Mediterranean gas can be developed.

Assessment of investments in the oil and petroleum products sector

Investments in the oil sector primarily relate to investments in exploration of new hydrocarbon reserves, with the aim of increasing domestic oil and gas production, or extending the commercial production of hydrocarbons to 2050, and investing in the modernization of refining capacities in order to ensure the competitiveness of domestic production of petroleum products.

Total investments in the renewal of reserves and the modernization of refining capacities in the period from 2020 to 2050 are estimated at:

- hydrocarbon exploration - HRK 37.5 to 112.5 billion (€5 to 15 billion),
- modernization of refining - HRK 3.5 billion (€470 million).

Assessment of investment in the renovation of building stock and other energy efficiency measures

The most significant contribution to reduction of energy consumption is the energy renovation of buildings. In the household sector 10,000 housing units are projected to be renewed annually. In the services sector, the specific heating needs of the total building stock in 2050 are projected to be 55 kWh/m^2 per year. This roughly represents renovation of the existing building stock eligible for renovation at an annual rate of 1.6%.

The total investment cost of energy renovation of buildings is calculated using the present values of assumed renovation prices up to nZEB standards (nearly-zero energy buildings). For residential buildings the price is 1,500 kn/m2, while in non-residential buildings it is 2,500 kn/m2, due to the existence of more complex technical systems in such buildings. The calculation results for both scenarios are shown in Table 5.91.

Table 5.91 **Assessment of investment in the renovation of the building stock**

Period	2021-2030	2031-2040	2041-2050
Residential buildings [million m^2]	8.71	9.11	9.50
Non-residential buildings [million m^2]	4.88	4.88	4.88
Investment residential and non-residential [billion HRK]	13.06 (€1.74 billion)	13.66 (€1.82 billion)	14.25 (€1.9 billion)
TOTAL [billion HRK]	40.97 (€ 5.46 billion)		

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050

The achievement of the objectives will also be significantly influenced by the construction of new buildings, which, by virtue of the legal obligation from 2021 onwards, must be in the nZEB standard. Given that this is a regulatory measure, it does not need to anticipate financial incentives, but nevertheless an estimate of the necessary investments has been made, which will mostly come from the private investment.

Table 5.92 **Investment assessment for nZEB new construction**

Period	2021-2030	2031-2040	2041-2050
nZEB new construction [million m^2]	10.93	14.72	15.11
Investment nZEB new construction [billion HRK]	38.26 (€5.1 billion)	51.53 (€6.87 billion)	52.89 (€7.05 billion)
TOTAL [billion HRK]		142.68 (€19.02 billion)	

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050.

Assessment of investments in infrastructure for the introduction of alternative fuels in transport

An assessment of investment in infrastructure for the transfer of alternative energy sources to transport vehicles and vessels is presented in Table 5.93. Investment costs include the procurement and installation of electricity transfer charging stations (home charging stations, slow charging stations up to 22 kW, 50 kW fast charging stations, over 50 kW fast charging stations), compressed natural gas filling stations (together with compressed biomethane), liquefied natural gas and hydrogen, and the cost of connecting to the electricity grid.

Table 5.93 **Assessment of investment in infrastructure for the use of alternative energy sources in transport vehicles / vessels**

Period	2021-2030	2031-2040	2041-2050
Electricity [million HRK]	247.5 (€32.99 million)	697.0 (€92.89 million)	2211.9 (€294.8 million)
CNG (CBM) [million HRK]	190.0 (€25,32 million)	68.0 (€9.06 million)	115.6 (€15.41 million)
LNG [million HRK]	110.0 (€14.66 million)	68.0 (€9.06 million)	57.8 (€7.7 million)
Hydrogen [million HRK]	18.0 (€2.4 million)	30.6 (€4.08 million)	91.0 (€12.13 million)
Total by period [million HRK]	565.5 (€75.37 million)	863.6 (€115.09 million)	2476.3 (€330 million)
TOTAL [billion HRK]		3.905 (€ 0,52 billion)	

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050.

The assessment of investment needs for the production of biofuels related to the production of advanced biofuels as listed in Schedule A, Appendix IX of the RED II Directive, and the anaerobic digestion plant of the feedstock in Schedule A, Appendix RED II of the Biogas Production and Purification Plant in Biomethane are presented in the following table.

Table 5.94 **Assessment of investments in infrastructure for the production of advanced biofuels as listed in Schedule A, Appendix RED II of the Directive**

Period	2021-2030	2031-2040	2041-2050
Biodiesel [million HRK]	2,743 (€365.57 million)	275 (€36.65 million)	
Bioethanol [million HRK]	978 (€130.34 million)	218 (€29.05 million)	
AD and purification of biogas into biomethane [million HRK]	6.5 (€0.87 million) (€0.87 million)	51 (€6.8 million) (€6.8 million)	173 (€23.06 million) (€23.06 million)
Total by period [million HRK]	3,727.5 (€497 million)	544 (€72.5 million)	173 (€23.06 million)
TOTAL [million HRK]		4,444.5 (€592.33 million)	

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050.

Assessment of investments for solar thermal collectors

The cost of the system today is estimated at HRK 5,000 /m^2 (€ 665/ m^2), with an expected reduction to around HRK 4,500/m^2 (€600/m^2), taking into account a 1% reduction in technology cost per year, as well as an increase in GDP and the average wage (i.e. the said cost takes into account the total labour cost and equipment). The estimated investment by 2050 would amount to HRK 9.1 billion (€1.2 billion), with an average annual sales of about 65,000 m^2 of collectors.

Table 5.95 **Estimated investment in solar thermal collectors**

Year	Industry 2050	Households 2050	Services 2050	Total (2019- 2050) 2050	Replacement of existing systems	Total 2050
Final consumption (Mtoe)	0.0217	0.045	0.034	0.1007		
Final consumption (GWh)	252.3	523.3	395.4	1,171.1		
Collector area (000 m^2)	382.4	793.1	599.2	1,774.9	250.0	2,024.9
Investment by 2050 (Billion HRK)	1,721 (€0.23 billion)	3,569 (€ 0.48 billion)	2,696 (€ 0.36 billion)	7,987 (€ 1.06 billion)		9,112 (€ 1.21 billion)

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050

Assessment of total investments in the energy sector

The total estimated investment for the period 2020-2050 by category is presented in Table 5.96. The total investment in reference Scenario 2 is HRK 133.7 billion (€17.82 billion) or HRK 4.45 billion (€0.59 billion) annually.

Table 5.96 **Estimated total investment in 2020-2050 (excluding the building sector)**

Investment category	TOTAL billion HRK	Annual investments billion HRK/year
Production of electricity	52.5 (€7 billion)	1.749 (€0.23 billion/year)
Transmission of electricity	17.8 (€2.37 billion)	0.593 (€0.079 billion/year)
Distribution of electricity	30.0 (€4 billion)	1.000 (€0.13 billion/year)
Transmission and distribution of natural gas	10.7 (€1.43 billion)	0.357 (€0.048 billion/year)
Oil and gas sector	3.5 (€0.47 billion)	0.117 (€0.016 billion/year)
District heating	1.8 (€0.24 billion)	0.060 (€0.008 billion/year)
Transport sector infrastructure	8.3 (€1.11 billion)	0.278 (€0.037 billion/year)
Solar heating systems	9.1 (€1.21 billion)	0.304 (€0.041 billion/year)
TOTAL	133.7 (€17.82 billion)	4.45 (€0.59 billion/year)

Source: Energy Development Strategy of the Republic of Croatia until 2030 with an outlook to 2050

The largest share of investments relates to the electricity system: HRK 100 billion (€ 13.33 billion), 75% of total investment.

CYPRUS

Cyprus

Economic and Political Background

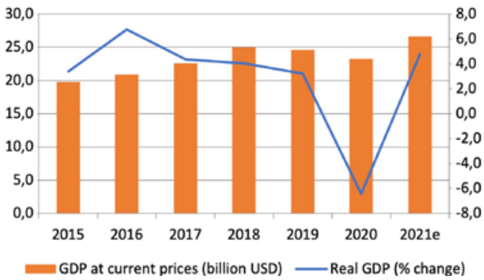
Cyprus's GDP fell 4.5% year-on-year in the fourth quarter of last year, worsening from the 4.3% contraction recorded in the third quarter. All in all, the economy shrank 5.0% in 2020, contrasting 2019's 3.1% expansion and logging the worst reading since 2013 during the Cypriot financial crisis.

Q4's downturn was mainly driven by a pronounced drop in consumer spending and exports. Household consumption fell 6.4% in annual terms in the fourth quarter, which contrasted Q3's 5.2% expansion. Meanwhile, fixed investment bounced back in Q4, growing 21.5% and swinging from the 5.6% contraction recorded in the prior quarter. Moreover, public spending growth ticked up to 10.1% in Q4 from 10.0% in Q3.

On the external front, exports of goods and services tumbled 28.8%, below the 27.2% plunge tallied in the prior quarter. Conversely, imports of goods and services dropped at a slower rate of 5.3% in Q4 (Q3: -12.8% y-o-y). On a working-day and seasonally-adjusted quarter-on-quarter basis, economic growth slowed notably to 1.4% in Q4 from 8.9% in Q3. Looking ahead, the imposition of a second lockdown in January, followed by softer, albeit still-tight, restrictions in February, is likely weighing on the recovery in the first quarter of the new year. However, conditions are expected to improve - mostly in the second half of the year - in line with vaccination progress, which should bolster domestic activity and allow for the revival of the crucial tourism industry. In addition, incoming EU funds and the ECB's loose monetary policy stance should further support the recovery.

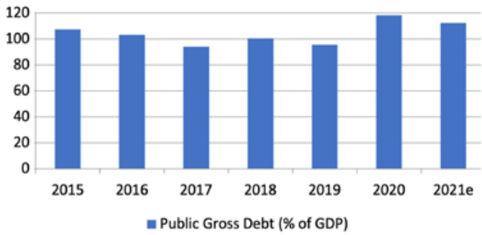
IMF estimates that Cyprus's GDP will expand by 4.7% in 2021, significantly higher than -6.4% in 2020.

Figure 5.67 **Cyprus's GDP and its annual GDP growth**



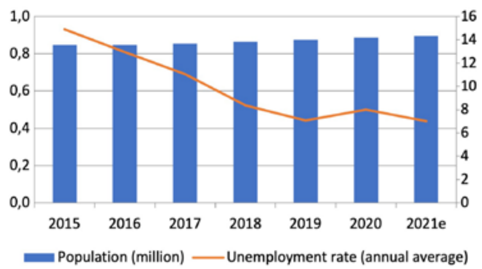
Source: IMF World Energy Outlook (October 2020)

Figure 5.68 **Cyprus's Public Gross Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.69 **Cyprus's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy[1]

The implementation of an energy policy in Cyprus while attaining the climate and environmental targets requires a radical transformation of the energy system over the next decade (2021 - 2030) and, therefore, the implementation of significant

[1] Adapted from information available on the Cyprus National Energy and Climate Plan.

investments in energy infrastructure as well as in energy efficiency. Major investments have been planned and scheduled in renewable energy, transformation of networks and the introduction of smart meters in power distribution, power transmission networks, importing and using natural gas for increasing energy efficiency in power generation, energy efficiency in households, businesses, public sector and water sector, transport infrastructures and sustainable mobility, as well as in technological research.

The national targets for the next decade are specified in detail in the National Climate and Energy Plan (NECP) on a mid-term basis, up to 2030, and should serve as a basis for an ambitious long-term strategy aiming towards the reduction of GreenHouse Gas (GHG) emissions by 2050. Therefore, the decarbonisation dimension is the first and foremost component of the NECP structure.
The NECP elaborates on the five dimensions of the Energy Union, i.e. decarbonisation (which is broken down into two distinct sections: GHG emissions and renewable energy sources), energy efficiency, security of energy supply, internal energy market, and research, innovation and competitiveness.

The main objective of the NECP is to design and plan cost-effective policies and measures that will help to achieve the medium- and long-term national energy and climate goals, will contribute to the economic development of the country and will also respond to the challenge of other environmental goals.

In this context, the main goals set out in the preparation of the national energy planning and the preparation of the NECP are:

- Achievement of national targets for reducing GHG emissions, to increase the participation of Renewable Energy Sources in domestic energy consumption and to achieve end-use energy savings in final energy consumption.
- Enhancement of energy supply security.
- Strengthen the competitiveness of Cyprus' economy.
- Protection of consumers while strengthening their role in the energy system.
- Setup and operation of a competitive internal energy market.

Moreover, the implementation of the above energy policy is formulated by an integrated strategy comprising the following main parameters:

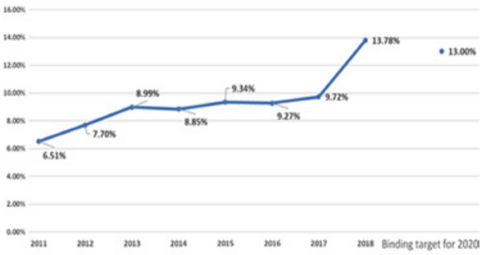
- The liberalization of the electricity market by abolishing the monopoly of the Electricity Authority of Cyprus (EAC) for the generation and supply of electricity through market opening and plans to introduce natural gas for power generation.
- The establishment and operation of centralized import and storage terminals holding strategic and operating oil stocks.
- The implementation of programmes related to the use of energy conservation technologies, the utilization of indigenous Renewable Energy Sources (RES) and the protection of the environment from industrial pollution.
- The promotion of other energy sources which are more efficient and friendlier to the environment, such as biofuels and natural gas.
- The development and exploitation of the country's indigenous energy sources including hydrocarbons.
- Building strong bilateral ties and creating new allies in the region, based on cooperation in the field of energy and resource management, exploitation and exports, in order to take advantage of the synergies emerging from the exploitation of hydrocarbons.

(a) Targets, Objectives & Strategy

The progress of Cyprus in relation to the RES and energy efficiency 2020 targets is presented in Tables 5.97 and 5.98, according to the data provided by the Energy Service of the Ministry of Energy, Commerce & Industry (MECI). According to the preliminary results of 2018 Cyprus has already achieved its binding target for 13% share of RES in the gross final energy consumption and the sectoral RES Heating & Cooling target. This was achieved mainly thanks to the contribution of solar thermal (38% share in RES production in 2018) as well as heat pumps.

Recently there was an assessment of the calculation methodology for the contribution of heat-pumps in the RES Sector. Based on the methodology followed (as defined in Article 5(1)(b) and (4) of Directive 2009/28/EC) there was a significant increase in RES share in heating due to Renewable Energy from heat-pumps [2].

Figure 5.70 **RES share in the gross final energy consumption**



Source: MECI

However, based on current data it does not seem possible to reach the target of RES share in transport and electricity. At the same time, if the large RES electricity (RES-E) projects are implemented on time, the RES-E sectoral target might be achievable by 2020. One of the government measures to achieve the 10% RES share in transport, was the increase of the percentage of biofuels (at 7,3% according to R.A.A. 11/2020) that the suppliers of transport fuels (petrol and diesel) are obliged to blend with conventional transport fuel.

Concerning the national indicative target for primary energy savings (375.000 toe by 2020), this is expected to be achieved. Based on the measures implemented between 2010 - 2016, the primary energy savings during that period accounted to 121.815 toe, or approximately 32,5% of the target. Following the implementation of the additional measures in the 2017-2020 period, the estimated energy savings by 2020 are expected to be 380.815 toe, or approximately 101,6% of the target.

However, the national indicative target for 2020 regarding the primary energy consumption in Cyprus is not expected to be achieved (the target for 2020 is 2.2 Mtoe and the primary energy consumption was 2.5 Mtoe in 2017)[3].

Finally, according to the 4th National Energy Efficiency Plan (NEEP), the mandatory cumulative energy savings target (241.588 toe) for Cyprus for the 2014-2020 period is expected to be achieved by the implementation of the measures included in the NEEP.

Table 5.97 **Progress of Cyprus in relation to the RES 2020 targets**

Sectoral RES Target	Year 2018*	Target by 2020	
Heating/Cooling	37,11%	23,5%	indicative
Electricity production	9,37%	16%	indicative
Road Transport	2,5%	10%	binding
Total share of RES (%)	13,78%	13%	binding

*The results of 2018 are preliminary
Source: MECI

Table 5.98 **Progress of Cyprus in relation to the energy efficiency 2020 targets**

Sectoral RES Target	Year 2018*	Target by 2020
	2017	2020
Indicative target for primary energy consumption (Mtoe)	2,5	2,2
Mandatory cumulative energy savings target for the 2014-2020 period (toe)	68.978	241.588
National indicative target for primary energy savings (toe)	121.815*	375.000

*The data is for 2016
Source: MECI

Regarding the national energy and climate targets for 2030, Cyprus has set quantitative targets, which are presented in Table 5.98. The energy and climate targets present opportunities, benefits and advantages for the national economy, the energy system and civil society, in general, as well as challenges that need to be overcome.

[2] Information available on the Cyprus National Energy and Climate Plan
[3] Information gathered from the 4th National Energy Efficiency Plan (NEEP)

Table 5.99 **Cyprus 2030 Energy & Climate targets**[4]

Greenhouse gas emissions
Emissions in the non-ETS sectors to be reduced by 20,9% compared to 2005.
Emissions in ETS sectors to be reduced by 24,9% compared to 2005
RES in the final energy consumption
Share of RES in gross final energy consumption to reach 23%
Share of RES in gross final electricity consumption can reach at least 26%
Share of RES in heating and cooling to reach 39%
Share of RES in the transport sector to reach 14%
Improving energy efficiency
Final Energy Consumption of 2,0 Mtoe in 2030, representing 13% reduction in final energy consumption*
Primary Energy Consumption of 2,4 Mtoe in 2030, representing 17% reduction in primary energy consumption*
Achieving cumulative energy saving of 243,04 ktoe during 2021-2030

* compared to the respective projection for Cyprus in 2007 in the EU PRIMES 2007 Reference Scenario
Source: Cyprus National Energy and Climate Plan

(b) Sectorial Energy Policy[4]

Table 5.100 presents the key policy priorities for each dimension of the NCEP, which are deemed necessary for attaining the aforementioned objectives (Table 5.99). These policy priorities are the axes for developing specific measures under each dimension.

All these policy priorities and the specific measures resulting from their implementation are part of an integrated plan for the optimal attainment of the national energy, environmental, socio-economic and development objectives, which requires consistency, horizontal combination and coordination in monitoring the priorities and implementing the measures. A key requirement for attaining the objectives set out in the context of NECP is to understand that the progress made in each individual sector automatically affects the progress made in the other sectors. Consequently, the impact of the measures that are finally planned and implemented do not affect just one topic and section of the NECP, but has an impact on the overall development of the energy system.

Table 5.100 **Key policy measures planning priorities**

Pilar	Key policy planning priorities
GHG emissions and removals	• Promotion of natural gas as intermediate fuels for the decarbonisation of the energy system • Promotion of renewable energy sources • Improvement of energy efficiency in buildings, industry and infrastructure • Reduction of emissions in the transport sector • Reduction of fluorinated gas emissions • Reduction of emissions from agricultural sector • Reduction of emissions from waste sector • Increase carbon sinks
Renewable energy sources	• Various RES Support schemes for Self-Consumption • Synergies with other sectors (Energy Efficiency, Waste, Security of supply and Internal Energy Market) to promote RES in all energy sectors • Support schemes for RES to participate in the Electricity Market • Replacement of old Solar Collectors for households • Replacement of Solar Collectors for Commercial purposes and use of Solar Technologies for High process heat and/or Solar Cooling • Old vehicle scrapping scheme and financial incentives for the purchase of electric vehicles (both new and used) • Promotion of the open loop Geothermal Energy • Installation of RES and Energy Efficiency technologies in Public Buildings. • Electricity Storage Installations, Framework development and possible financial incentives. • Various other measures for RES in Transport (New bus contracts (using alternative fuels, electricity, gas, and biofuels B100), Use of Biofuels (and biogas) in Transport Sector • Other indirect measures that will help to increase energy efficiency and thus the RES Share in transport. • Statistical Transfer of Energy to be examined (exporting Energy in case of Electricity Interconnector)

4 Information available on the Cyprus National Energy and Climate Plan

Pilar	Key policy planning priorities
Energy efficiency	• Energy efficiency obligation scheme for energy distributors • Energy Fund of Funds providing soft loans for energy efficiency • Individual energy efficiency interventions and energy efficiency retrofits in governmental buildings • Implementation of information and education measures • Support schemes/incentives for promoting energy efficiency in households, enterprises and wider public • Energy efficient street lighting. • Additional floor space "allowance" for buildings exceeded the minimum energy efficiency requirements set by national law • Advanced Metering Infrastructure Plan. • Promotion of energy efficiency in enterprises, through voluntary agreements • Action plan for increasing energy efficiency the road transport. • Energy efficiency in water sector • Vehicle excise duty based on CO2 emissions • Energy consumption fee for Res and energy efficiency applied on electricity bills. • Excise tax on road transport fuels exceeding the minimum levels by EU legislation
Security of supply	• Introduction of natural gas via LNG imports and the development of the necessary infrastructure • Increasing the flexibility of the national energy system
Internal Energy market	• Promotion of electricity interconnectivity of Cyprus via the project of common interest EuroAsia Interconnector • Development of internal natural gas network pipeline infrastructure • Investments for development and secure operation of the transmission electricity system • Promotion of the necessary regulatory framework and projects for the operation of the competitive electricity market • Promotion of the EastMed pipeline project

Pilar	Key policy planning priorities
Research, innovation and competitiveness	• Fund of funds • New Industrial Policy • Establishment of the Deputy Ministry of Innovation and Digital Transformation • European Structural and Investment Funds in the new Programming Period 2021 - 2027 • Revision of national funds regarding research and innovation with the aim to boost climate and energy priorities

Source: Cyprus National Energy and Climate Plan

Governmental Institutions[5]

This section provides brief information on the key institutions in Cyprus related to energy matters, with an emphasis to their main roles and responsibilities and how these institutions collaborate/fit together. The institutions presented below include: (i) authorities involved with policy making, such as the Ministry of Energy, Commerce & Industry (MECI), the Cyprus Energy Regulatory Authority (CERA), and (ii) energy related organizations involved with policy implementation, such as the Transmission System Operator (TSO), the Electricity Authority of Cyprus (EAC), the Natural Gas Public Company (DEFA), the Cyprus Organization for the Storage & Management of Oil Stocks and the Cyprus Hydrocarbons Company (CHC).

(a) Ministry of Energy, Commerce & Industry (MECI)

The Ministry of Commerce & Industry (MECI) is responsible for the formulation of present policy and monitoring its implementation on matters pertaining to trade, energy, industry and consumers, in such a way that it will contribute positively towards the further development of the national economy and the well-being of the population of the island. In addition, the Ministry supervises/oversees and is associated with the rest of the energy related institutions in Cyprus.

[5] Adapted from information available on the corresponding webpage of each institution/organization.

(b) Energy Service, Ministry of Energy, Commerce & Industry

The Energy Service is a Service that operates under the Ministry of Energy, Commerce, & Industry and has the role of monitoring the implementation of the National Policies related with energy efficiency, energy efficiency in buildings, biofuels and fuels. Also, Energy Service, makes suggestions and recommendations about possible support schemes and mechanisms to promote those topics.

(c) Hydrocarbons Service, Ministry of Energy, Commerce & Industry

The Hydrocarbons Service, operates under the Ministry of Energy, Commerce, & Industry. The main responsibilities of the Hydrocarbons Service are related to the prospecting, exploration and exploitation of hydrocarbons within the territory of the Republic of Cyprus, not only at a regulatory level but at an operational level as well, and for strengthening the geostrategic role of Cyprus in the region.

(d) Cyprus Energy Regulatory Authority (CERA)

The Cyprus Energy Regulatory Authority (CERA) is an independent authority responsible for the regulation of the electricity and gas markets, with exclusive rights to issue licenses for all activities and infrastructure relating to electricity and gas in the internal energy market, to regulate and approve tariffs, to supervise licensed activities, to resolve disputes, to protect consumers, to secure a reliable energy system, to monitor supply and demand balances in the energy market, and to develop an economically viable and competitive energy market.

(e) Transmission System Operator (TSO) and Distribution System Operator (DSO) for Electricity

The Transmission System Operator (TSO) for Electricity was established in 2003. The functions and responsibilities of the TSO Cyprus are to secure the operation of the Electricity Transmission System and to manage the electricity market on an objective, non-discriminatory basis, in a competitive environment, while at the same time, supporting and promoting electricity generation from renewable energy sources. The TSO Cyprus ensures access to the Transmission System of all producers and suppliers of electricity.The Distribution System Operator (DSO) is designated by the EAC and is responsible for the operation, maintenance and development of the distribution system. The DSO is, moreover, a neutral market facilitator and a catalyst regarding the implementation of new technology such as, for example, smart grids, which provide effective services to all market participants (producers, suppliers, consumers and prosumers) via smart infrastructure and technologies, thus enabling transparent, impartial, fair and non-discriminatory access to the network.

(f) Electricity Authority of Cyprus (EAC)

The Cyprus Electricity Authority (EAC) was founded in 1952. The Electricity Authority of Cyprus (EAC) has been for many years a vertically integrated company (governed by the electricity Law) active in power generation, transmission, distribution and the supply of electricity to consumers in Cyprus. EAC is the Distributor System Owner (IMS) as it is the owner of the distribution system. The EAC is carrying out Operational Unbundling in compliance with the Regulatory Decision of the Cyprus Energy Regulatory Authority (CERA), which implements the corresponding provisions of the EU. Through "operational unbundling", the four "core regulated activities" - the monopoly activities of transmission and distribution and the competitive activities of generation and supply - have become separate operations within the EAC. Operational unbundling ensures that the EAC does not exploit its dominant position and that equal opportunities are offered to private sector producers or suppliers. For the implementation of operational unbundling, the EAC has created independent units for its core regulated activities in such a way as to guarantee their reliable and independent operation.

(g) Natural Gas Public Company (DEFA)

Concerning the development of the internal gas market and network, a Natural Gas

Company, known by its Greek Acronyms as DEFA, has been established and is responsible for the import, storage, distribution, transmission, supply and trading of natural gas, and the management of the distribution and gas supply system in Cyprus (to be established). The council of Ministers of the Republic of Cyprus has issued a decree dated 18/06/2008, which appoints DEFA as the sole importer and Distributor of Natural Gas in Cyprus and directs DEFA to proceed with securing the necessary Natural Gas quantities at the best commercial terms.

(h) Cyprus Organization for the Storage & Management of Oil Stocks

This is the organization responsible for maintaining and managing emergency stocks of crude oil and/or petroleum products as per the relevant obligation as applied to all EU Member States. These stocks have to be available at all times and only the Minister of Energy, Commerce, Industry and Tourism has the right to order the release of part or the whole of the oil stocks in order to deal with shortages in energy supply.

(i) Cyprus Hydrocarbons Company (CHC)

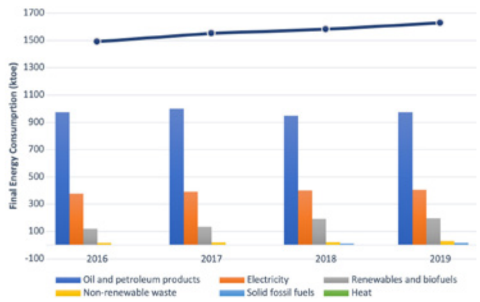
The Cyprus Hydrocarbons Company (CHC), formerly known as the Cyprus National Hydrocarbons Company (CNHC), is entitled with the mission of managing all commercial aspects related with the exploitation of indigenous hydrocarbon resources (i.e. acts as the 'commercial arm' of the government regarding oil and gas exports and the trading/ supply of natural gas).

Energy Demand and Supply

National Energy Demand [6]

The final energy consumption in Cyprus amounted to 1.581 ktoe in 2018, showing an increase of 6% during the period 2016-2018. The level recorded for 2016 and 2017 was 1.552 ktoe and 1.491 ktoe, respectively.

Figure 5.71 **Final energy consumption for the period 2016 - 2019**



Source: Eurostat 2021

In 2018, 60,1% of energy demand was covered by the use of oil and petroleum products, followed by 25,4% the use of electricity and Renewables and biofuels with 12,2%.

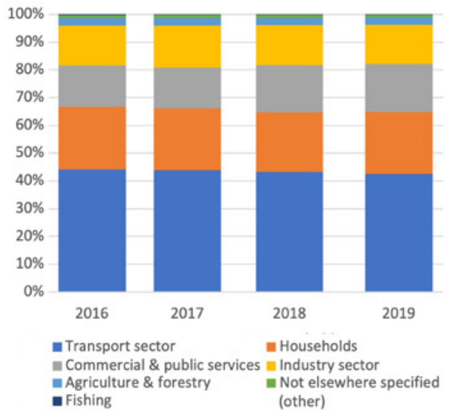
Renewables and biofuels had a 12,2% share (192,6 ktoe) of the final energy consumption in 2018. Respectively, renewables and biofuels had an 8,7% share (135,7 ktoe) in the final energy consumption in 2017 and an 8,1% share (120,2 ktoe) in 2016. The consumption of renewables and biofuels rose by 60,3% in the period 2016-2018.

Electricity consumption increased by 6% in 2018 compared to 2016. This can be attributed to the broad trend for electrification in the economy and mainly on the continued electrification of the heating and cooling sector. In addition, the considerable volume of electricity consumed in the transport sector is expected to have a significant role in the growth of electricity demand in the following years.

The use of solid fossil fuels is still preferred by the domestic cement industry, despite the environmental impact of the combustion of such fuels and the international restrictions in place, primarily due to their competitive prices. A total of 13,6 ktoe of solid fossil fuels were consumed in 2018. The data presented in Figures 5.71 and 5.72 were obtained by Eurostat, and are based on the new methodology of energy balances as applied since April 2020.

6 Statistical data obtained by EUROSTAT (2020). It should be noted that the fuel consumption of international aviation is not taken into account.

Figure 5.72 **Final energy consumption by sector for the period 2016 - 2019**



Source: Eurostat 2021

As shown in Figure 5.72, transport remained the most energy consuming sector in Cyprus with 678,5 ktoe in 2018. Its annual share exceeds 40% of the final energy consumption throughout the three-year period (2016-2018). Residential is also a large energy consuming sector, with a consumption of 337,2 ktoe in 2018. The residential share was 23% in 2016, decreasing to 21% in 2018. In 2016 the energy consumption in the industrial sector amounted to 225,3 ktoe. In 2017 it recorded a sharp increase of 9%, but in 2018 it recorded a 3% decrease, reaching 276,5 ktoe. The other sectors of the economy (i.e. Agriculture & forestry, Fishing) represented an average of just 4% share in the total final energy consumption for the period 2016 - 2018.

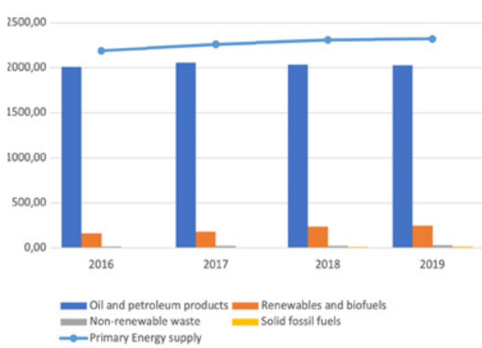
National Energy Supply[7]

Primary energy supply is defined as the national energy production plus energy imports, minus energy exports and international bunkers, then plus or minus stock changes. It should be noted that the consumption of international aviation is not taken into account.

Similarly, as with the case of the final energy consumption, energy supply in the period 2016-2018 was mostly based on oil products (Figure 5.73). The oil and petroleum products share decreased from 91,9% in 2016 to 88.1% in 2018 whereas the share of RES increased by 2,9% in this period (7,4% share in 2016 increasing to 10,3% in 2018). Finally, solid fossil fuels and non-renewable waste constitutes a very small share of the energy supply (0.7% in 2016 increasing to 1.6% in 2018).

Useful insights can be provided through a comparison of the final energy consumption with the primary energy supply. Even though final energy consumption undergoes a moderate increase in the following years, primary energy supply seems to follow a relatively stable trend. This is an indication of an improved energy efficiency that comes from the use of more energy-efficient technologies for heating and cooling and the increase of use of renewable energy technologies. In the following years is anticipated that energy efficiency will be improved as electricity will be generated in more efficient gas-fired plants.

Figure 5.73 **Energy supply (ktoe) from the period 2016 - 2019**



Source: Eurostat 2021

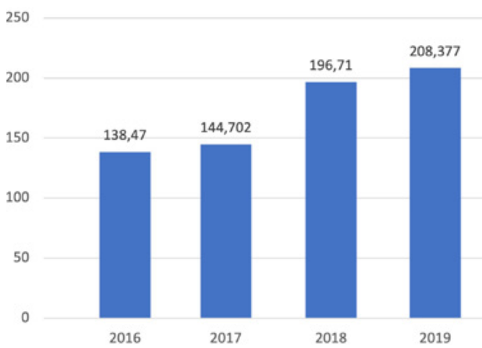
Energy Balance[8]

Domestic primary energy production increased from 138,5 ktoe in 2016 to 196,7 ktoe in 2018, without any radical changes as to the main sources of energy (Figure 5.73). Thus, solar thermal remained the country's main source of indigenous energy, accounting

7 Statistical data obtained by EUROSTAT (2020). It should be noted that the fuel consumption of international aviation is not taken into account.

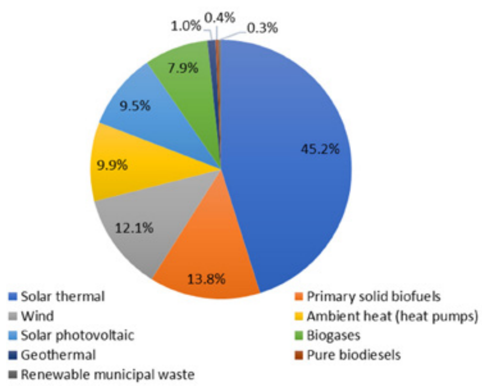
for more than 45% of energy production in the period 2016-2018. Specifically, in 2018, 72 ktoe were produced by solar thermal systems for hot water production. The contribution of solid biofuels and wind farms for the same period were 13,4% and 11,8%, respectively. It is worth mentioning that the share of photovoltaics systems in the same period (2016-2018) increased by 36,7% (from 12,5 ktoe in 2016 to 17,2 ktoe in 2018). Figure 5.74 illustrates the aggregate share of domestic primary energy production for the period 2016-2018.

Figure 5.74 **Primary energy production (ktoe) for the period 2016 - 2019**



Source: Eurostat 2021

Figure 5.75 **Aggregate share of primary energy production for the 3-year period 2016-2018**

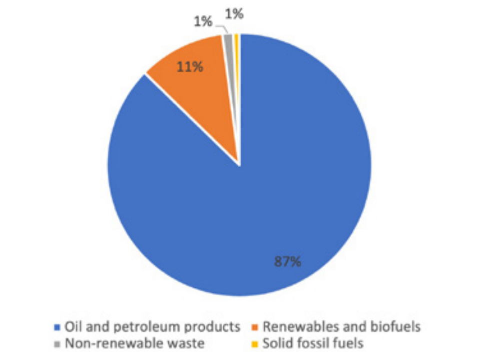


Source: EUROSTAT 2020

Energy Mix[9]

The energy mix continues to be dominated by oil and petroleum products, which contributed by 88.1% of the total energy supply in 2018. Over the period 2016-2018, the share of oil products declined, while the contribution of renewable energy to energy supply has steadily increased reaching 10,3% in 2018 (Figure 5.75). The situation is expected to change in the near future as RES penetration increases and once natural gas from LNG imports becomes available to the local market (replacing oil fuel for the electricity generation and in industry, and in the long term the household sector). It is anticipated that this will be reflected by a relatively large decline in the share of oil products in the energy mix, although the impact will not be that high, since the demand for oil products in the transport sector will continue to be dominant.

Figure 5.76 **Energy Mix for 2019**



Source: EUROSTAT 2021

Energy Dependence [10]

The energy dependency rate shows the proportion of energy that an economy must import in order to meet its energy needs. It is defined as net energy imports (imports minus exports) divided by gross inland energy consumption plus fuel supplied to international maritime bunkers, expressed as a percentage.

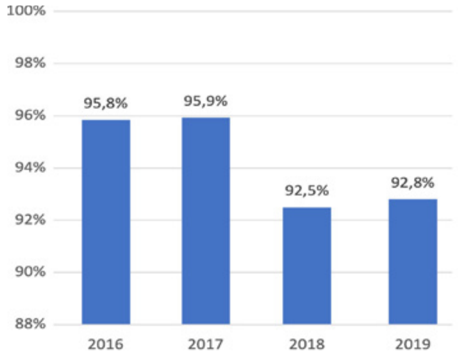
8 Statistical data obtained by EUROSTAT (2020). It should be noted that the fuel consumption of international aviation is not taken into account.

9 Statistical data obtained by EUROSTAT (2020). It is noted that the fuel consumption of international aviation is not taken into account.

10 Statistical data obtained by EUROSTAT (2020).

Due to the country's limited indigenous energy resources, Cyprus is a highly energy dependent, country at a level above the average of the European Union. In the EU in 2017, the average energy dependency was 55%, while in Cyprus this was around 96%. As Figure 5.77 shows, the dependency rate on energy imports has decreased from 96% in 2016 and 2017 to 92% in 2018.

Figure 5.77 **Energy dependency rate for the period 2016-2019**

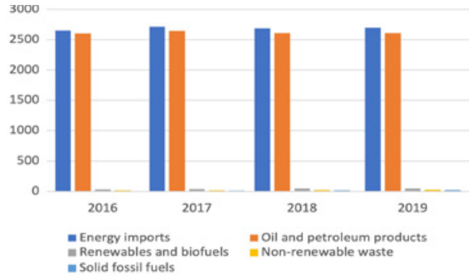


Source: Eurostat 2021

Nevertheless, energy dependence on account of imported oil products is overwhelmingly high as these products also constitute the dominant energy source for all sectors. Specifically, in 2018, oil and petroleum products accounted for 97% of all energy imports, while solid fossil fuels, non-renewable waste and RES & biofuels accounted for the remaining 3% (Figure 5.78).

With regard to the trend of imports by type of energy, the share of oil and petroleum products in the total imports decreased slightly between 2016 and 2018. On the other hand, the share of RES & biofuels imports increased during this period from 1,2% to 1,7%, while Non-renewable waste remained constant.

Figure 5.78 **Energy imports breakdown for the period 2016-2019**



Source: Eurostat 2021

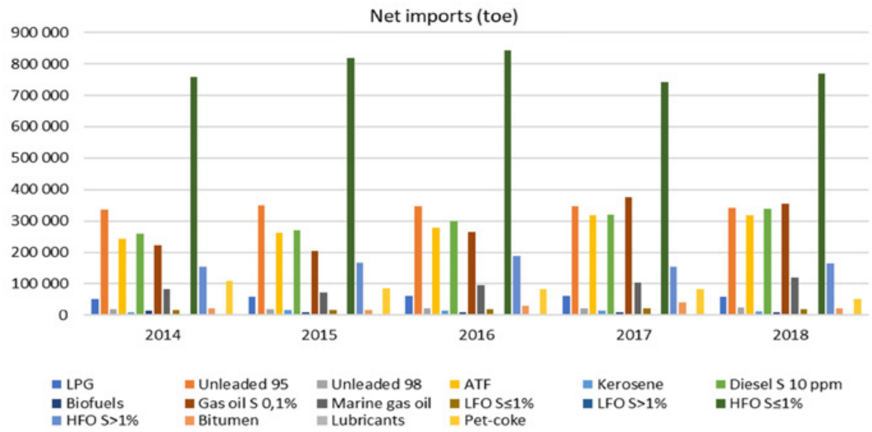
The Energy Market

Petroleum Products

(a) Petroleum products Supply and Demand

In Cyprus the main source of energy is provided by petroleum products, which are exclusively imported. Petroleum products are used for transportation, power generation and space heating and cooking. Cyprus imports around 2,5 million MT per year (2018) of refined oil products, while most of them are imported from neighbouring countries, e.g. Greece and Israel. In particular, the possibility to diversify the current energy supply is very limited because of the small amounts of petroleum products that are imported in Cyprus due to the limited size of the internal market, the lower transport (shipping) costs from neighbouring countries and the availability of petroleum products with the required specifications due to similar climatic conditions.

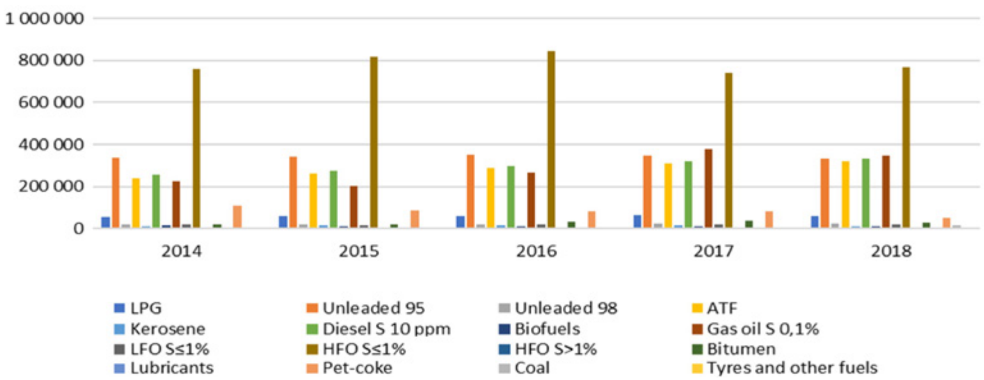
Figure 5.79 **Net imports (toe) of petroleum products for the period 2014-2018**



Source: National Energy & Climate Action Plan 2020-2030

Dependence on the import of petroleum products and a very low rate of utilisation of indigenous energy sources create a framework of reduced security for the uninterrupted supply of energy, and exposure of the economy to the fluctuations of global oil prices.

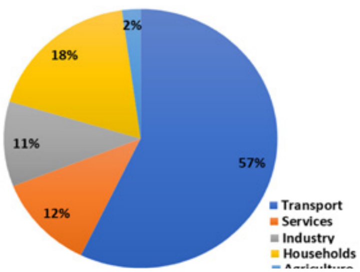
Figure 5.80 **Primary consumption (toe) of petroleum products for the period 2014-2018**



Source: National Energy & Climate Action Plan 2020-2030

The **total final consumption** of oil products in 2018 amounted to 1,78 mtoe (including imports of oil for electricity generation). The oil products were mainly used in the transportation sector, with a consumption of 1,01 mtoe, i.e. approximately 56,7% of the total final consumption of oil products in 2018. Services (including commerce & hotels) consumed 0,21 mtoe, representing 12% of the total oil consumption, agriculture consumed 0,039 mtoe, representing 2% of the total oil consumption, households consumed 0,324 mtoe, representing 18% of the total oil consumption, while the industry consumed 0,189 mtoe, 11% of the total oil consumption in 2018.

Figure 5.81 **Final energy consumption of oil products share per sector (%) of the total final energy consumption**



Source: National Energy & Climate Action Plan 2020-2030

Oil Imports / Dependence

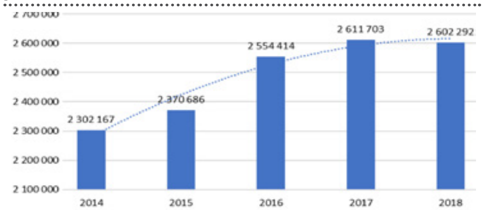
With Cyprus being an 'isolated energy island', it exhibits a high degree of dependence on imported oil products, while the main fuels currently used in power generation are fuel oil and diesel oil. The various oil products imported are used in the transport, households, services, agriculture and industry sectors.

Currently, imported oil products include LPG, unleaded gasoline, jet fuel (ATF - Aviation Turbine Fuel), kerosene, diesel, gasoil, LFO, HFO (mainly used for power generation purposes by EAC), bitumen (used in road asphalt) and pet coke (used for cement production by the Vasilikos Cement Company).

Apart from these, also biofuel blends, marine bunker fuels and lubricants are imported, which have other own applications.

Imports of oil and petroleum products, except HFO (i.e. LPG, gasoline, kerosene, diesel, heating oil, marine gasoil, LFO) constituted 61,5% (1,6 mtoe) of the total oil products imports in 2018, while 13,7% (0,36 mtoe) concerned imports of HFO, which was used almost exclusively for power generation. The import of pet-coke reached 0,05 mtoe (1,9% of total oil-products supply) and the rest amounted to the import of bitumen (0,021 mtoe) for road construction purposes (non-energy use).

Figure 5.82 **Petroleum products imports for the period 2014-2018**



Source: National Energy & Climate Action Plan 2020-2030

c) Upstream Sector-Domestic Production and Exploration

Currently, there is no domestic production of oil or oil products. However, the energy sector of Cyprus is transforming due to new natural gas discoveries within its EEZ. There are strong signals that Cyprus will soon move from exploitation, to exploration and production. The hydrocarbon exploration activities taking place offshore Cyprus do not preclude the possibility of oil findings, while the natural gas reserves already discovered in Block 12 are expected to contain some valuable condensates, which may be converted into synthetic oil.

(d) Downstream and Midstream Sectors Infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

Sometime ago the government decided the relocation of the oil terminals, including liquefied petroleum gas (LPG), as well as other related facilities from the seafront of

Larnaca area. Based on that decision and subsequent decision to develop the necessary infrastructure for an LNG import terminal, the New Energy and Industrial Area of Vasilikos was established in November 2014. The relocation of the oil products storage except LPG is expected to be completed in the first quarter of 2020 and that of LPG around the end of 2020 early 2021.

The modern and upgraded larger oil storage facilities will help improve the security of supply, since larger quantities of petroleum products could be stored on the island as it will also be possible to unload larger tankers. Alongside with the abovementioned procedures, the Cyprus Organization for the Storage and Management of Oil Stocks (KODAP), the Central Stockholding Entity of Cyprus established by "The Maintenance of Oil Stocks Law of 2003", (N.149(I)/2003), is planning to build its own oil storage terminal in the Energy and Industrial Area of Vasilikos in order to relocate its own oil stocks which are held abroad and in private terminals in Cyprus, as well as, to reduce the annual storage cost.

To this effect KODAP has signed a € 35 million financing agreement with the European Investment Bank (EIB) to finance the construction of a privately owned oil terminal. The privately owned terminal of KODAP will be built at the Vasilikos Energy Center and will consist, at this stage, of six liquid fuel storage tanks with a total capacity of 200.000 cubic meters, pipelines and pumping stations, fire safety and protection systems, as well as buildings. This is another move towards strengthening the security of supply since the majority of the oil stocks will now be kept on the island.

The Cyprus oil market is dominated by 10 local petroleum products trading companies which import and supply oil products in Cyprus for retail, industrial and commercial purposes. Three (3) of them share more than 70% of the market share. After the cease of the operation of the Cyprus Petroleum Refinery in Larnaca in April 2004, these trading companies import finished petroleum products from refineries abroad, store them at their facilities and then distribute them out to the local market through their own network of petrol stations. In 2020 the total number of petrol stations operating in Cyprus was 305.

Automotive and heating fuels are traded in Cyprus through the petrol stations located throughout the country (most of the petrol stations in Cyprus are owned by the aforementioned oil importing companies). Since the accession of Cyprus to the EU, oil products' prices are set freely, while the Minister of Energy, Commerce & Industry has the authority to set a price ceiling for specific oil products and for a specific duration in the event of emergency or during times of intense price volatility.

LPG is currently only used only for domestic, industrial, services (hotels and restaurants) and heating purposes and is sold both in bottles and in bulk. LPG bottles delivery has been imposed with reduced VAT equal to 5%.

The Cyprus Organization for the Storage & Management of Oil Stocks (KODAP) purchases its strategic products through tenders. EAC procures gasoil and HFO through periodic tenders for its own needs in fuel for power generation. The storage facilities for oil products in Cyprus are presented in Table 5.101:

Table 5.101 **Oil products storage terminals/capacity**

Owner/Operator	Type of Facility	Petroleum Products & Tanks	Storage Capacity
Electricity Authority of Cyprus (EAC)	Storage facilities (and Single Point Mooring system for oil imports) at the three power stations of EAC (Vassiliko, Moni, Dekelia), for its own fuel needs (operational and strategic stocks) for power generation	Gasoil	95.000 cubic meters
		HFO	112.000 cubic meters
Electricity Authority of Cyprus (EAC) - stocks of KODAP	1 Tank at Vassiliko	Gasoil	30.000 cubic meters
Cyprus Petroleum Storage Company Ltd (ex. Cyprus Petroleum Refinery Ltd)	Tank farm	Bitumen	10.000 metric tonnes
VTTV Ltd (private company wholly owned by VTTI which was created with a 30% share of Vitol Group)	Storage hub and associated infrastructure (including truck loading facilities) and a jetty for oil import/export	Gasoil (12 tanks for import/export)	287.991 cubic meters
		Heating Gasoil (0.1% sulphur content) ? 1 tank for imports	11.345 cubic meters
		Automotive Gasoil (10ppm sulphur content) - 2 tanks for imports	32.054 cubic meters
		Unleaded gasoline (total of 8 tanks: 5 for import/export and 3 for imports)	138.078 cubic meters
		Gasoline-MTBE (1 tank for import/ export)	10.422 cubic meters
		Jet Fuel (total of 3 tanks: 2 for import/ export and 1 for imports)	62.698 cubic meters
		FAME (a diesel blending agent) - 1 tank	2.038 cubic meters
Petrolina Group (a local Cypriot private company)	Storage terminal (+ truck loading facilities)	Gasoline, Auto / Heating Gasoil, Kero Bunkering fuels Jet fuels bitumen	104.139 cubic meters

Source: Author's research

(e) Security of Supply

The Cyprus Organization for the Storage & Management of Oil Stocks (KODAP), in the context of the relevant EU Directive obligation maintains, oil stocks in Cyprus and Greece, at a level equivalent to 90-days average local consumption. The use of indigenous sources of energy, such as hydrocarbon deposits and RES will contribute towards increasing the flexibility of the national energy system and ensuring the security of energy supply. The promotion of RES and objectives regarding demand response and energy storage can play an important role.

(f) Planned New Projects

Following an official decision, the decommissioning of the existing oil products storage terminal is foreseen, as well as for the relocation of the existing storage facilities of the local petroleum and LPG trading companies. A strategic oil stocks depot will be set up and operated by the Cyprus Organization for the Storage & Management of Oil Stocks (KODAP). As an interim solution, until the finalisation of design & construction of the new fuel farm (KODAP), the stocks being held were transferred to the VTTV terminal, a private fuel tank farm. The new Fuel Farm will be situated on the north/east of the Vasilikos Cement Company, and it will consist of the following: Four (4) tanks of CLASS A (Mogas) products, and seven (7) tanks of CLASS B (Jet fuel, and Diesel) products will be erected, of total storage capacity of approximately 430.000 m3. The tank sizes are identical and are of 45m in diameter and 22m height. Petroleum and LPG storage facilities, for the storage of the operating stocks, is to be operated by the local petroleum and LPG trading companies.

Natural Gas

No internal gas market exists yet in Cyprus, but efforts are underway for bringing gas to the island to be used in the local market for power production but also in due course to cover the demand of tourists and commercial household consumers as well. Regarding indigenous hydrocarbon deposits offshore Cyprus, the Aphrodite natural gas field operator and the Republic of Cyprus have completed negotiations for the Aphrodite Field Development and Production Plan (AFDPP), which was approved in 2019. As a result, an Exploitation License for the production of the Aphrodite Field was issued in November 2019. According to the AFDPP, natural gas production is expected to begin in 2025. The Aphrodite Field gas, is going to be transmitted to Egypt via a subsea pipeline, to the Idku LNG Terminal in Egypt for liquefaction and re-export, as well as for we in the domestic market.

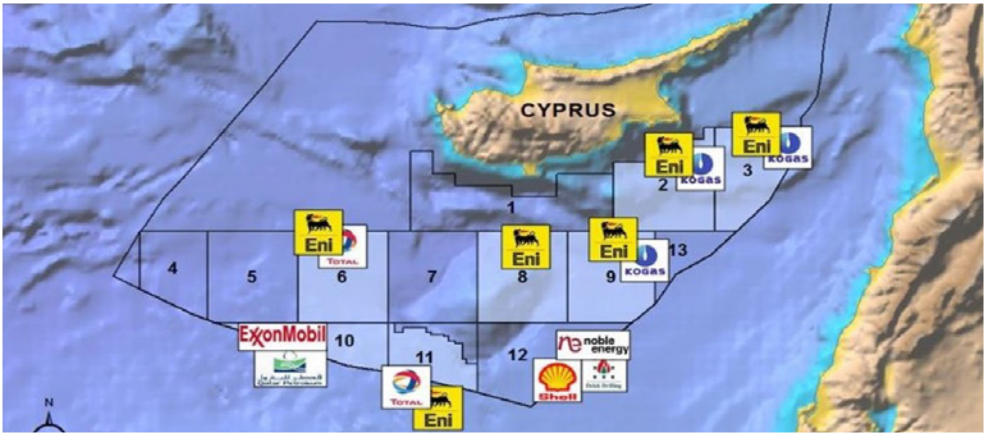
In the framework of the 1st Hydrocarbon Licensing Round held in 2007, an Exploration License for Block 12 was granted to Noble Energy for an initial period of three years and a Production and Exploration Contract (PSC) was signed in 2008. Exploratory and appraisal drilling operations in Block 12 resulted in a natural gas discovery of considerable size ('Aphrodite' field: 125 bcm gross mean estimated resources). Five more Exploration Licenses were awarded during the 2ndHydrocarbon Licensing Round conducted in 2012, to Eni/Kogas for Blocks 2, 3 & 9 and to Total for Blocks 10 & 11.

Hydrocarbon exploration activities also took place by ENI (in Blocks 2, 3 and 9) and Total (in Blocks 10 and11). ENI also carried out 2 exploratory drillings during the period 2014-2015 in Block 9, but these did not result in any findings.

In February 2018, the ENI / Total joint venture completed the first exploratory well "Calypso 1" in Block 6, which resulted in a gas discovery. Moreover, in February 2019, the ExxonMobil/Qatar Petroleum consortium discovered a substantial gas reservoir in the Glaucus-1 well in Block 10. The consortium spudded an appraisal well in the block in late December, 2021.

Finally, hydrocarbon exploration activities in Cyprus's Exclusive Economic Zone are ongoing and a number of exploration wells are planned for the next two years, with the aim of discovering further hydrocarbon deposits. In December 2021, The Cypriot government awarded a license for natural gas exploration rights for the offshore block 5 to a consortium made up of ExxonMobil and Qatar Petroleum.

Map 5.17 **Offshore exploitation licenses in Cyprus's Economic Exclusive Zone (EEZ)**



Source: Republic of Cyprus

(a) Natural Gas Supply and Demand (in bcm)

An LNG import terminal will be constructed in the Vasiliko Port, which is to be operated by the Cyprus Ports Authority. It will include a floating storage and regasification unit (FSRU) comprising a gas export system and loading arm equipped with meters, gas compressors, filters, heaters, and export arm pipelines. The FSRU will be permanently berthed in Vassilikos bay and have a storage capacity of 125.000m³. It will be capable of unloading LNG from LNG carriers ranging in size between 120.000m³ and 217.000m³. The Cyprus LNG market segment and potential gas consuming sectors include: Industrial users, power generation, domestic & commercial users, tourist facilities, road transport & the marine fuel/bunkering. Recent studies showed that the N. gas quantity to be delivered to the FSRU in LNG form is estimated at 0,8 bcm per annum, stating in 2022 doubling the amount by 2039. At present there is no gas infrastructure on the island such as a gas transmission and distribution grid. However, there are plans by DEFA (see next section) to establish such a grid over the coming years.

(b) Domestic Gas Market

The domestic gas market is regulated by the Cyprus Energy Regulatory Authority (CERA). All relevant EU Directives have been fully transposed and comprise the regulatory regime for the gas sector in Cyprus. The entities currently involved in the domestic gas market include: the Ministry of Energy, Commerce & Industry, the Cyprus Energy Regulatory Authority (CERA) and the Public Natural Gas Company (DEFA). Recently, the Natural Gas Infrastructure Company (ETYFA) was also established. DEFA is the authority responsible for the import, supply, wholesale transmission and distribution of natural gas in Cyprus.

(c) National N. Gas Policy -Strategic Plan

The introduction of natural gas to the local market in Cyprus is a main priority for the energy sector. The project, to introduce LNG through regasification unit (FSRU) is estimated at €290 million and €101-million has been secured through a grant from the EU under the Connecting Europe Facility (CEF) financial instrument, while the Cyprus Electricity Authority will contribute €43 million securing a 30% stake at ETYFA. Furthermore, ETYFA will cover the remaining part of the cost with funding from international lenders such as the European Investment Bank and the European Bank or Reconstruction and Development, with state guarantees. The infrastructure's operational expenditure (Opex) are estimated at €10,5m a year. Furthermore, DEFA has launched an additional tender for the supply of LNG supply, attracting expressions of interest from 25 suppliers, among the most dominant in the global LNG market. DEFA intends to import 0,6 bcm of LNG through a Gas Sale - Purchase Agreements (GSPAs) with duration between three to four years, maintaining the option to also purchase LNG from the spot market.

(d) Planned new projects

The EastMed pipeline (Project of Common Interest no. 7.3.1), is promoted by the IGI-Poseidon S.A. group and aims at connecting the European market with the gas resources of the Eastern Mediterranean region.

Map 5.18 **The EastMed pipeline**

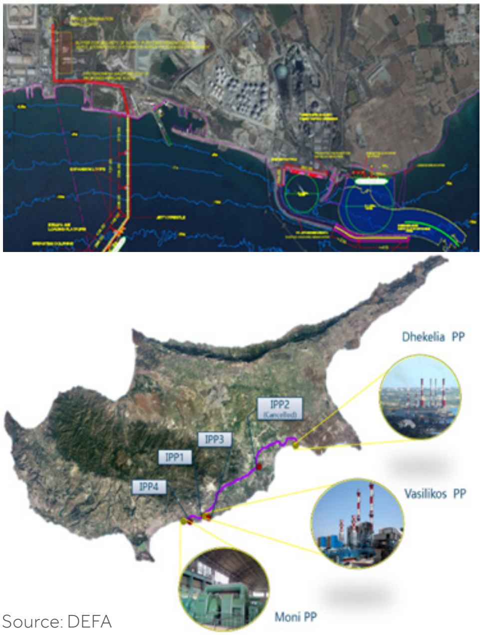
Source: https://gr.euronews.com

The EastMed pipeline will have an initial capacity of up to approximately 10 Bcm/year. In a second phase, the pipeline's capacity may expand up to 20 Bcm/y. It is an approximately 1900 km off-shore-pipeline divided into the five following sections: (1) offshore in the Levantine basin to Cyprus; (2) Cyprus-Crete; (3) Crete-Peloponnese; (4) Peloponnese-W. Greece; (5) W. Greece-Thesprotia. From there, at Florovouni, it will connect to the off-shore section of the Poseidon pipeline enabling the direct flow of gas to Italy and beyond in the European continent. Moreover, via the potential connection with the Greece-Bulgaria Interconnector, the EastMed pipeline can also allow the Levantine gas to reach the Balkan markets while the metering & regulating station at Megalopoli provides a connection to the Greek gas transmission system.

This Project of Common Interest (PCI) is also related to the energy security dimension, as it promotes diversification of energy sources and routes, ends the isolation of Cyprus and Crete, supports new gas production in the Eastern Mediterranean, including EU indigenous sources, and facilitates gas exchanges in South-Eastern Europe. It also contributes to the energy efficiency dimension, as natural gas is a more efficient fuel than the other fossil fuels and also help towards decarbonisation because natural gas has lower greenhouse gas emissions than those from conventional fuels.

CyprusGas2EU (Project of Common Interest no. 7.5 former 7.3.2) is being promoted by MECI and aims at introducing Natural Gas via LNG imports to the island of Cyprus in order to end the current energy isolation of Cyprus, by establishing the required infrastructure. Following the completion of a feasibility study in 2016, the Government of Cyprus (GoC) decided to proceed with a policy which will result in Liquified Natural Gas (LNG) imports in Cyprus, by approving the import of LNG. The LNG import route shall act as the single gas supply route until the indigenous gas sources become available for the Cyprus market, and will serve as an alternative supply route for ensuring the security of inland gas supply.

Map 5.19 **CyprusGas2EU project**



Source: DEFA

As per the above, a tender was announced by ETYFA (Natural Gas Infrastructure Company) in October 2018 for the LNG Import infrastructure in Vasilikos Bay), aiming for completion by early 2022. This infrastructure aims to end the energy isolation of Cyprus and has many cross-border impacts/ benefits for Cyprus and the Eastern Mediterranean region.

The tender entails the design, construction and operation of the project, which consists of (a) the procurement of a floating storage and regasification unit (FSRU), of at least 125,000 cubic meters storage capacity, to unload LNG from LNG carriers ranging in size from 120,000 cubic meters to 217,000 cubic meters (Q-Flex), (b) the Construction of offshore infrastructure for the permanent berthing of the FSRU, and (c) Onshore natural gas infrastructure and related construction components for gas delivery to the Vasilikos power station and potentially other gas consumers. On 13th of December 2019, a contract was awarded to the joint venture China Petroleum Pipeline Engineering, Metron, Hudong-Zhongua Shipbuilding and Wilhelmsen Ship Management.

The capital cost of the project is estimated to be €300 m, spread over three years (2020 - 2022). It is also expected that the project capital costs will be financed through a combination of a grant from the EU CEF (Connecting Europe Facility) of up to €101 m (project was approved by CEF in January 2018), debt financing (e.g. EIB, etc.) and an investment by the Electricity Authority of Cyprus (EAC) of €43m. The Operational and Maintenance cost is estimated to be around €200mn for a 20-year period.

The EuroAsia Interconnector is the official EU project developer of the 2.000MW electricity interconnector between Israel, Cyprus, Greece and Europe. The EuroAsia Interconnector is a leading European Project of Common Interest (PCI) labelled as an EU "electricity highway" connecting the national electricity grids of Israel, Cyprus and Greece through a 1.208 km subsea HVDC cable. It is expected that **EuroAsia** Interconnector construction will be completed by end of 2023. The statutory permit granting procedure for PCI "EuroAsia Interconnector" started in November 2019 and will be completed until the comprehensive decision is taken by NCA, by end of 2020. Immediately after the completion of the granting procedure, the construction phase will begin and expected to last for three years. Consequently, commercial operation will start by Q1 2024 where an interconnectivity level of 15% will be achieved.

Map 5.20 **Map of EuroAsia interconnector**

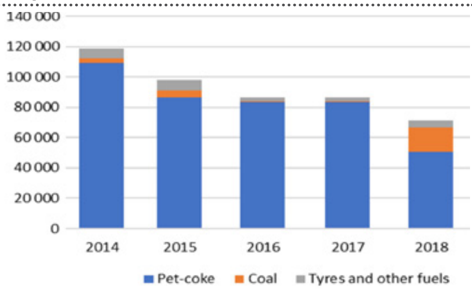
Source: https://euroasia-interconnector.com/

Solid Fuels

All solid fuels used in Cyprus are imported and include pet coke, coal and since 2005 a small quantity of used car tires that come from the domestic market. During the year 2018, the use of solid fuels (pet-coke, coal and tyres) was about 3,1% of the total primary consumption, while this share fell to nearly zero in 2013. The quantity of used tyres are disposed off locally. In 2018, 910.071 new tires were imported.

The imports of solid fuels in Cyprus aim exclusively at meeting the energy needs of the domestic cement industry.

Figure 5.83 **Primary consumption of Solid Fuels in the period 2014-2018**



Source: National Energy & Climate Action Plan 2020-2030

Electricity

(a) Electricity Market

For more than 50 years, the electricity market in Cyprus had been operating as a monopoly under a vertically integrated company, the Electricity Authority of Cyprus (EAC). Since its establishment in 1952, EAC has been the only responsible entity for the generation, transmission, distribution and supply of the electricity to the final customers. In 2003 and as a first step to achieve the transition into a liberalised electricity market, the Transmission System Operator Cyprus (TSO Cyprus) and the Cyprus Energy Regulatory Authority (CERA) were established in accordance with the relevant European Union Directives. The Ministry of Energy, Commerce & Industry (MECI) is responsible for the overall policy, strategy and for transposing EU Directives into national legislation.

The main functions and responsibilities of the TSO Cyprus include the operation of the electricity transmission system and the management of the electricity market in an objective and non-discriminatory basis and in a competitive environment. At the same time, the TSO should support and promote electricity generation from renewable energy sources. The responsibilities of the CERA include overseeing and regulating the market for electricity and gas, ensuring effective and fair competition, protecting the interest of consumers, ensure safety, quality, competence, and encourage the use of renewable energy sources for electricity production.

On 1st January 2004, the electricity market was liberalised by 35%. Five years later, on 1st January 2009, the electricity market was further liberalised for all "non-domestic" consumers, thus bringing the total market liberalisation to 65%. Despite the fact that the electricity market was liberalised 'on paper', actual liberalisation still lacks behind significantly, and in fact never happened. A number of issues have prevented the smooth transition and operation of a competitive electricity market in Cyprus, and are summarized as follows: (a) The vertically integrated EAC (which had a monopoly on the production and sale of power since 1952) and its Public Corporate status, (b) the lack of national experience regarding the functioning of liberalized electricity markets, (c) the small size of the electricity market itself, and (d) the newly established institutional structures (e.g. CERA, TSO).

(b) Electricity Transmission

Regarding the electricity transmission, the voltage commonly used at national level for the overhead lines is 132kV. Only two overhead lines are designed for 220kV (circuit length is 90.8km) but these operate at the commonly used voltage of 132kV. There are also some overhead lines designed for 132kV but operated at 66kV, in addition to the overhead lines operating at 66kV. Apart from these, underground cables exist mainly operating at 132kV and very few at 66kV. The Transmission System is complemented with a great number of substations.

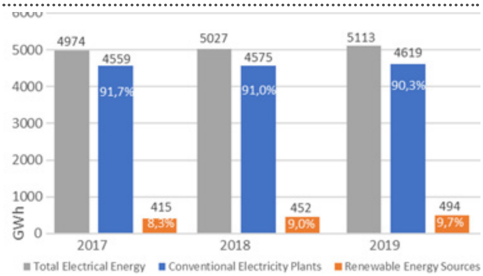
(a) Electricity Supply and Demand

Electricity in Cyprus is generated by:

- Three power stations operated by the Electricity Authority of Cyprus (EAC) - Conventional Power Plants
- Independent producers using Renewable Energy Sources (RES).

In 2019 the total electricity generation in Cyprus was around 5.113 GWh, with most of it (90,3%) generated by the three conventional power plants of EAC[12]. Electricity generation witnessed gradual growth over the last three years due to increased demand.

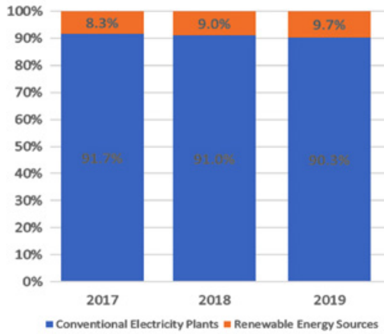
Figure 5.84 **Electricity Generation for the period 2017-2019**



Source: TSO Cyprus

The proportion of electrical energy from conventional power plants has been decreasing over the last three years since there is increasing penetration of renewable energy systems (mainly PV systems). More specifically, the proportion of electrical energy from conventional power plants decreased from 91,7% in 2017 to 90,3% in 2019, while the percentage of electrical energy generated by RES increased accordingly. As of 2017, the electrical energy generated by renewable energy sources accounted for 415 GWh, corresponding to 8,3% of the total electrical energy generated in Cyprus. In 2019, the corresponding electrical energy accounted for 494 GWh that represents 9,7% of the total electricity generation in Cyprus.

Figure 5.85 **Share of electricity generation for the period 2017-2019**



Source: TSO Cyprus

(b) Installed Capacity of conventional electricity plants

Cyprus power generation system consists of three thermal power stations with a total installed capacity of 1.478MW, as analysed in Table 5.102:

Table 5.102 **Installed Capacity of the three thermal power stations**

Vasilikos Power Station	
Unit Capacity	Total Power
3 x 130 MW Steam Units	390 MW
1 x 38 MW Gas Turbine	38 MW
2 x 220 MW Combine Cycle Units	440 MW
Dhekelia PowerStation	
Unit Capacity	Total Power
6 x 60 MW Steam Units	360 MW
2 x 50 MW Internal Combustion Engines	100 MW
Moni PowerStation	
Unit Capacity	Total Power
4 x 37,5 MW Gas Turbines	150 MW
Total Installed Capacity	**1.478 MW**

Source: EAC

Vassiliko Cement Works has 11 MW of internal combustion engines, which are capable of burning heavy fuel oil or gasoil and could (probably) be modified to burn natural gas[13].

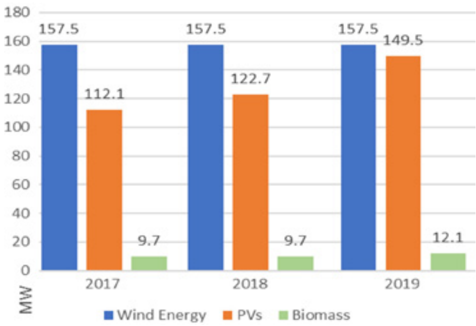
[12] Obtained from TSO Cyprus
[13] Obtained from the report "Master plan of the Vasilikos area" (October 2013)

The steam units at Vasilikos are used for base load generation, while the steam units of Dhekelia are used for intermediate load generation. The gas turbines are mainly used during system peak loading. All stations use heavy fuel oil for the steam turbine units and gasoil for the gas turbine units. The combined cycle units use gasoil as fuel until the arrival of natural gas in Cyprus [14].

(c) Installed Capacity of Renewable Energy Systems

RES applications for electricity generation include wind energy systems, PV systems and biomass systems. No hydroelectric plants or nuclear plants currently exist in Cyprus and none are planned either. The total installed capacity of RES in Cyprus increased from 279,3MW in 2017 to 319,1MW in 2019, corresponding to 14,3% increase. During this 3-year period, PV installations had a rapid growth, biomass systems had a slight increase, while wind energy systems remained at the same level. The share of each system in the total RES capacity is illustrated in Figure 5.86.

Figure 5.86 **RES installed capacity by system for the period 2017-2019**



Source: TSO Cyprus

(d) Planned New Capacity - Investments

The import of natural gas will initiate the gradual conversion of the oil-fired power stations, in order to run on natural gas fuel and will also encourage the establishment of independent power producers. Already, the combined cycle units and the 3 steam turbines at Vasilikos power station that currently use gasoil and heavy fuel oil, respectively, have the capability to run on natural gas. So far, there are 4 licensed independent power producers (1 x 260MW, 1 x 230MW, 1 x 105MW, 1 x 17,5MW)[15] with none of these being implemented yet. EAC was also licenced for the construction of an 160MW power station in Vasilikos area.

In an attempt to stimulate the penetration of RES-e and get closer to the 2020 national binding target, the government of Cyprus introduced two support schemes during the last years, targeting large RES-e producers (>1MW). In the first Support Scheme, projects of 116,3MW total capacity (102MW PV systems, 12MW wind energy systems, and 2,3MW biomass systems) were licensed, while in the second Support Scheme the capacity of the projects that proceeded to the final licensing was 260MW, all PV systems. So far (April 2020), 40 RES projects (36,5 MW total capacity) under the 1st scheme have been implemented. The rest projects under this scheme, as well as the projects under the second Support Scheme are due to be implemented within the following months.

(e) Electricity Imports - Exports

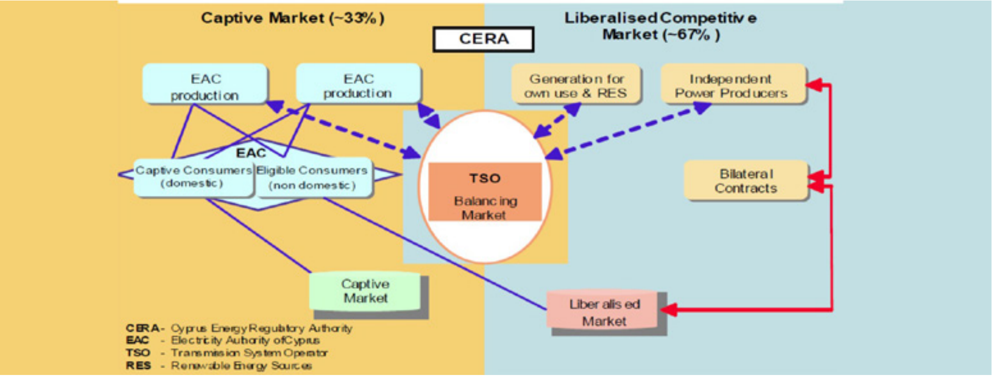
No electricity imports/exports currently exist due to the lack of interconnections between Cyprus and other countries.

(f) Tariffs

The domestic electricity market is regulated by the Cyprus Energy Regulatory Authority (CERA) under the relevant provisions of the Electricity Directive of the 3rd Energy Package, which have been fully transposed and dictate the regulatory regime for the electricity sector in Cyprus. The entities currently involved with the domestic electricity market are the Ministry of Energy, Commerce and Industry (MECI), the Cyprus Energy Regulatory Authority (CERA), the Electricity Authority of Cyprus (EAC), the Transmission System Operator (TSO) and the independent electricity producers and suppliers.

13 OObtained from EAC (https://www.eac.com.cy/EN/EAC/Sustainability/Pages/ElectricityProduction.aspx)
14 Obtained from CERA (https://www.cera.org.cy/el-gr/ilektrismos/details/katalogos-adeiwn)

Figure 5.87 **RES installed capacity by system for the period 2017-2019**



Source: EAC

However, this is about to change when the market gets fully liberalized and the new electricity market rules come into force. The full liberalization of the electricity market of Cyprus is projected to be in October 2021. Until then, market players can take part in the **transitional electricity market model** that has been in operation since the 1st of September 2017. In this transitional model, the electricity market participants, which can be licenced producers (from RES or conventional fuels) or licenced suppliers (until today 13 independent suppliers obtained licenses), conclude bilateral agreements (Power Purchase Agreements - PPA) amongst each other with the objective of selling/buying the generated electrical energy.

A licenced independent supplier will have the right to participate in the transitional electricity market model only once they agree bilateral contracts with customers (Power Supply Contracts - PSC) of at least 10MW total capacity. A licenced independent producer can participate in the transitional electricity market model only if their RES or conventional power station has a nominal power of at least 500kW.

Cyprus's electricity sector relies primarily on oil imports, while the electricity system in Cyprus is isolated (no interconnections with other countries exist yet). This makes the price of electricity exceptionally vulnerable to fluctuations in international oil prices. On the 1st of September 2017, CERA set a new tariff methodology that will be in force for at least 5 years from the date of implementation or until the full liberalization of electricity market. According to the new methodology, the number of tariffs decreased from 30 to 11. The amount (price) of the tariffs is revised and approved by CERA every year. The tariffs for industrial consumers (tariffs with codes 30, 40 and 50) have 8 different charging periods according to the month, the day and the time of the day (peak/off-peak) as shown on the following table:

Table 5.103 **Breakdown of energy charge periods**

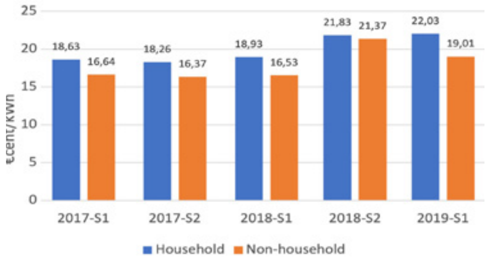
Periods	October - May		June - September	
	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
Peak	16:00 - 23:00	16:00 - 23:00	09:00 - 23:00	09:00 - 23:00
Off-Peak	23:00 - 16:00	23:00 - 16:00	23:00 - 09:00	23:00 - 09:00

Source: EAC

The average electricity price for household and non-household consumers in Cyprus for the first half of 2017 until the first half of 2019 are presented in Figure 5.88. Note that the prices include taxes, levies and VAT[16].

[16] Obtained from Eurostat (https://ec.europa.eu/eurostat/web/energy/data/database)

Figure 5.88 **Average electricity price for household and non-household units for the period 2017-2019**



Source: Eurostat

The electricity prices in Cyprus are among the highest in Europe and this is mainly attributed to the extensive reliance on oil-fired electricity generation, which continues to supply around 90% of the electricity demand. The increasing penetration of renewable energy sources, the forthcoming introduction of natural gas in the electricity production and the full liberalization of the electricity market are among the factors that can contribute to the reduction of the electricity prices, at least in long term.

The full liberalization of the electricity market that is projected to take place in October 2021 aims to:

- Create a competitive energy market that will offer security of electricity supply at competitive rates.
- Enhance the freedom of customers to make an effective choice of supplier.
- Continue to promote measures for the protection of vulnerable consumers.
- Allow RES power generation to enter the competitive electricity market.
- Enhance competition in the electricity generation business sector.

(f) Cross-Border Interconnections

The power system of Cyprus is completely isolated, as there are currently no interconnections to the electricity grids of neighbouring countries. However, a new project, involving cross-border interconnections, is planned and once this materializes it is expected to lift the current energy isolation of Cyprus, allowing electricity imports/exports.

(g) Planned New Projects

EuroAsia Interconnector Project

The integration of Cyprus energy system into the regional markets is pursued through the promotion of the EuroAsia Interconnector Project, which is a leading European Project of Common Interest (PCI) labelled as an EU "electricity highway" connecting the national electricity grids of Israel, Cyprus and Greece through a 1.208km subsea HVDC cable. This subsea electricity cable will carry up to 2.000MW of electrical energy produced, mainly from natural gas in power stations located in Cyprus and Israel, as well as from renewable energy sources. It will also allow for the reverse flow of electricity, thus enhancing the security of supply and lifting the energy isolation of Cyprus, adding at the same time stability to its electricity system.

The development and realisation of EuroAsia Interconnector constitute a very complex process. The implementation dates as provided to the European Commission, for the commencement of Stage 1 are as follows:

- Cyprus - Greece commissioning in December 2023
- Cyprus - Israel commissioning in December 2023

Map 5.21 **EuroAsia Interconnector Project**

Source: euroasia interconnector project

[17] Obtained from EuroAsia-interconnector (https://euroasia-interconnector.com/about-us/)
[18] Obtained from IGI-Poseidon (http://www.igi-poseidon.com/en/eastmed)

Eastern Mediterranean (EastMed) Pipeline[18]

EastMed is a 1.900km natural gas pipeline project that is intended to connect the gas reserves of the eastern Mediterranean with Greece.

The project is currently designed to transport initially 10 Bcm/y (billion cubic meters of gas per year) from the off-shore gas reserves in the Levantine Basin (Cyprus and Israel) into Greece and, in conjunction with the Poseidon and IGB pipelines, into Italy and other South East European countries. Furthermore, the pipeline would allow to feed Cyprus internal consumption with additional 1 Bcm/y.

The EastMed project current design envisages a 1.300 km offshore pipeline and a 600 km onshore pipeline. The pipeline, starts from the new natural gas discoveries in the East Mediterranean region and comprises the following sections:

- 200 km offshore pipeline stretching from Eastern Mediterranean sources to Cyprus;
- 700 km offshore pipeline connecting Cyprus to Crete Island;
- 400 km offshore pipeline from Crete to mainland Greece (Peloponnese);
- 600 km onshore pipeline crossing Peloponnese and West Greece.

The EastMed pipeline is preliminarily designed to have exit points in Cyprus, Crete, mainland Greece as well as the connection point with the Poseidon pipeline.

The project has been confirmed as a Project of Common Interest (PCI) by the European government. It is being developed by IGI Poseidon, a 50:50 joint venture between Public Gas Corporation of Greece (DEPA) and Edison International Holding.

The energy ministers of Greece, Israel, and Cyprus signed the final intergovernmental agreement for the pipeline project in Athens on January 21 2020.

The project has been confirmed as a Project of Common Interest (PCI) by the European government. It is being developed by IGI Poseidon, a 50:50 joint venture between Public Gas Corporation of Greece (DEPA) and Edison International Holding.

The energy ministers of Greece, Israel, and Cyprus signed the final intergovernmental agreement for the pipeline project in Athens on January 21 2020.

Map 5.22 **East-Med Pipeline**

Source: Euronews

Cyprus LNG import terminal

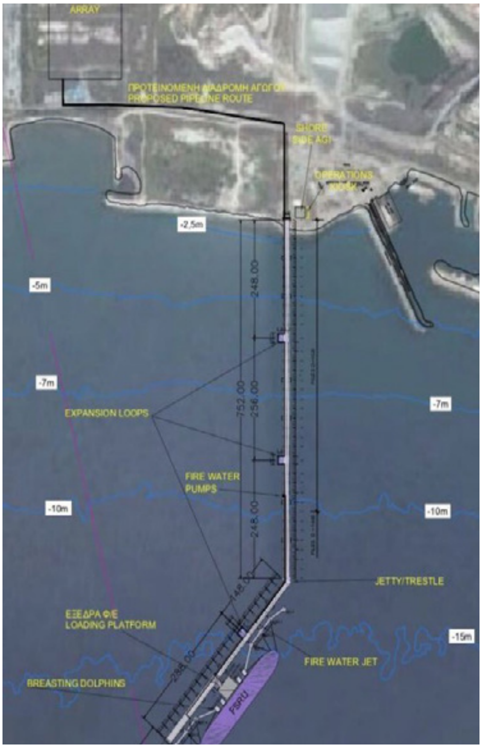
The FSRU-based LNG import project at Vasilikos Bay in Cyprus is meant to lessen the dependence of the island on heavy fuel oil and petroleum products for power generation. The project will initially supply gas to the Vassilikos Power Station (VPS) and later to the Moni and Dhekelia power stations and independent power producers.

The LNG import terminal will be constructed along the Vasiliko Port in Cyprus, which is operated by the Cyprus Ports Authority. It will include a floating storage and regasification unit (FSRU) comprising a gas export system and loading arm equipped with meters, gas compressors, filters, heaters, and export arm pipelines.

A multinational consortium led by the state-owned China Petroleum Pipeline Engineering has been awarded a contract for the construction of the LNG import terminal. Other consortium members are Metron Energy Applications, CPP, Hudong-Zhonghua

Shipbuilding and Wilhelmsen Ship Management. Under the contract, valued at €500M ($571.7M), the consortium will procure an FSRU of at least 125 000 m3 storage capacity and will also supply gas over 20 year period. It will be capable of unloading LNG from LNG carriers ranging in size between 120,000m³ and 217,000m³. The project is co-financed by the EU through the EU's Connecting Europe Facility (CEF)[19].

Map 5.23 **Cyprus LNG import terminal map**



Source: kathimerini.com.cy

RES Projects

With regard to the renewable energy sector, 145 PV projects of 260MW total capacity that were licensed under the 2nd Support Scheme for large RES-e projects, are due to be implemented in 2020-2021. Also, 37 projects (79,6 MW total capacity) out of 77 projects under the 1st Support Scheme that have not been implemented yet, are due to be completed during 2020 (Source: MECI).

Other small PV projects under the ongoing support schemes for net-metering systems (for residential and non-residential buildings) are expected to be implemented within 2020, contributing to the increase of RES share in the electricity generation mix of Cyprus. Until the end of 2019 and since 2013 when the scheme was initiated, 14.779 systems of around 54MW total capacity were implemented (Source: EAC). Also, some medium-size PV systems are about to be installed under the net-billing support scheme. Until the end of 2019 and since March of 2019 when the scheme was initiated, 72 PV systems of 4,3MW total capacity and 1 Biomass system of 2,4MW capacity were installed (Source: EAC).

By the Regulatory Decision 02/2018 (Act 259/2018) CERA invited the DSO to proceed with the appropriate actions to initiate the required procedures for the complete and massive installation of smart metering systems. The aim is to install 400.000 smart meters by 2027[20] based on the following timeline:

Table 5.104 **Timeline of smart meters installation**

Phases	Deadline	Smart meters installation
1st	January 2021	57.143
2nd	January 2022	57.143
3rd	January 2023	57.143
4th	January 2024	57.143
5th	January 2025	57.143
6th	January 2026	57.143
7th	January 2027	57.143

Source: CERA

Renewables

Cyprus has a great potential regarding Renewable Energy Sources (RES), which include solar and wind energy, biomass and the use of low enthalpy geothermal energy. All RES plants/systems in Cyprus are either: (1) autonomous systems (not connected to the electricity grid), or (2) producers of electricity from RES that are connected to the grid and feed their electricity into it, or (3) producers of electricity from RES

[19] Obtained from Europa.eu (https://ec.europa.eu/inea/sites/inea/files/cefpub/cef_implementation_brochure_2019.pdf)
[20] Obtained from CERA (https://www.cera.org.cy/Templates/00001/data/ektheseis/2018_en.pdf)

that are connected to the grid and use the electricity produced for their own use and feed the excess electricity into the grid (PV systems under net-metering scheme & PV or biomass systems under net-billing scheme) (4) Solar thermal systems for domestic hot water use.

(a) Overview of Sector's Development[21]

Despite the increasing contribution of renewable energy sources in the gross final energy during the last years, there is still plenty of room for further exploitation considering the country's real potential. During the period 2016-2018 the increase in the contribution of RES in the gross final energy consumption of the country increased from 9,27% to 13,78% (based on preliminary results). As an EU Member State, Cyprus must comply with a national renewable energy target currently set at 13% of gross final energy consumption from renewable energy by the end of 2020 and 23% by 2030.

During the period 2016-2018, the primary energy supply of RES had a significant increase of 47%, reaching 238,3 ktoe in 2018. Approximately 72 ktoe (51.8%) came from the production of hot water from solar thermal systems, 46 ktoe (19%) from the use of heat pumps, 28 ktoe (12%) from the use of renewable municipal waste, 17 ktoe (7%) from the use of photovoltaic systems and 13,2 ktoe (6%) from the use of biogas for electricity generation, 9 ktoe (3%) from the use of biofuels in transportation, 19 ktoe (8%) from the use of wind farms and 1,6 ktoe (1%) from geothermal energy systems.

Cyprus along with Israel were the first countries in the Mediterranean–European area back in the 1950's to start using solar energy for domestic water heating. Hence the citizens of Cyprus are familiarized with the use and utilisation of solar thermal technology for the production of hot water, since 92% of the households and over 50% of the hotels in Cyprus use solar water heating systems to cover the majority of their hot water needs.

According to an EU survey, the extensive use of solar thermal technology makes Cyprus one of the world's leading countries in thermal solar energy applications for residential uses, with nearly 1m² installed solar collector area per capita. Despite the extremely widespread proliferation of solar thermal systems for domestic hot water uses, the solar heat applications for Industrial processes in Cyprus are still limited.

(b) Incentives/Support Schemes for RES

The government of Cyprus has developed various support schemes and incentives for the promotion of RES and energy efficiency (EE) projects. The majority of these instruments are intended to be financed by the national budget, some with assistance from EU funds. The national support schemes that use the available funds from the Special Fund for RES & EE can be divided into 3 main categories: Support Schemes for RES, Grant Schemes for RES, and Grant Schemes for Energy Efficiency.

Most of the Support Schemes for RES are related to **Net Metering** and **Net Billing** and target residential, tertiary & industrial sectors. The Net Metering support scheme is open to household owners and SMEs from all sectors of economic activity. The size of the PV system should not exceed 10 kW. The Net Billing scheme is open to all enterprises from all the sectors of the economy. The size of the PV or biomass systems should be between 10kW up to 10 MW.

The Grant Scheme for RES targets the residential sector. Grants are available for the installation of domestic PV systems under the Net-metering scheme and replacement of domestic solar water heaters. In an attempt to further stimulate the penetration of RES-e and get closer to the national binding 2020 target, the Cyprus government introduced two Support Schemes during 2018-2019 targeting large RES-e producers.

21 Obtained from EUROSTAT (2020) and MECI

In the **first Support Scheme (phase I)** a total capacity of 120MW was offered to interested and potential investors. The scheme was open between October 2017 and April 2018 for project applications. During this period, the total capacity of the applications reached 395,3MW, mainly for PV systems. More specifically, the applications for PV systems, wind energy systems and biomass systems were 376,5MW, 16,5MW and 2,3MW respectively. The decision was to proceed to the final licencing of 101MW PV systems, 16,5MW wind energy systems, and 2,3MW biomass systems as these projects have been proven mature (Source: Ministry of Energy, Commerce and Industry).

The second Support Scheme (phase II) was ongoing between April 2019 and June 2019 with the available offered capacity to potential investors being at 150MW, regardless of the RES technology (i.e. several RES-e projects with capacity up to 150 MW in total could be licensed). Until the end of the scheme, applications for a total capacity of 350MW have been made. The MECI announced on the 16th August 2019 that the number of applications that have been approved exceeded the 150 MW, and thus an additional capacity of 110 MW was offered by MECI to cover the eligible applications, namely up to 260 MW. Eventually 260MW of PV systems were accepted (Ministry of Energy, Commerce and Industry).

A grant scheme for installation of car charging points (for electric or hybrid cars) and smart meters in homes has been already agreed by the Council of Ministers in November 2019 and is about to be announced and initiated during the following weeks (June 2020).

The support of investments for the exploitation of RES, the simplification of the licensing procedures and the establishment of a stable, transparent and safe investment environment regarding RES has been one of the basic priorities in Cyprus. In addition, according to the relevant EU Renewable Energy Directive, all new renewable energy sources installations have grid connection priority rights.

Cyprus continues to promote renewable energy investments and implement measures aimed at increasing the level of penetration of renewable energy sources into the power generation system. The new electricity market model takes into account a structured approach for the increase of electricity generation from Renewable Energy Sources and allows power generation from RES to enter the competitive electricity market.

According to the EU Directive 2009/28/EC, concerning the promotion of the use of energy from Renewable Energy Sources (RES), the share of energy from RES in all forms of transport by 2020 must be at least 10% of the final consumption of energy in transport (Cyprus has been granted a derogation from the inclusion of jet fuel in the calculation of the final consumption for all forms of transport). This obligation is met at a great degree by the blending of biofuels in conventional fuels.

(c)Installed Capacity per Source (in MW)[22]

At the end of 2019, the total installed capacity per RES-e was as follows:

• PV systems	149,5 MW
• Wind Energy systems	157,5 MW
• Biomass systems	10.4 MW

(d) Planned New Major Projects

Currently the planned projects include:

- 260MW RES projects that were licensed under the second Support Scheme for large RES-e projects.
- 79,6MW RES projects that were licensed under the first Support Scheme for large RES-e projects.
- 50 MW Concentrated Solar Power (CSP). The projected is to include 300 solar thermal receivers and hundreds of sun-tracking mirrors north of Limassol in Cyprus.
- Small-size PV projects under the ongoing support schemes for net-metering systems.
- Medium-size PV and biomass projects under the ongoing support schemes for net-billing systems.

[22] https://tsoc.org.cy/energy-generation-records/res-penetration/

Energy Efficiency and Cogeneration

Building sector [23]

Following the accession of Cyprus to the EU in 2004, specific measures and policies have been implemented towards improving the energy efficiency of buildings. As of late 2007, mandatory measures were implemented for energy saving through the insulation of the building envelope, for all new buildings and all existing buildings over 1.000 square meters which underwent major renovations. As of 1 January 2010, an additional minimum energy performance requirement was added to the effect that all new buildings should be classified as a minimum under energy class B in the Energy Performance Certificate (EPC).

This has led to the implementation of better thermal insulation. Moreover, the installation of a solar thermal systems for the production of hot water was made mandatory for all new dwellings, and the fitting of a standby installation for the use of renewable power systems was made mandatory for all new buildings. By the Decree of 2013, the maximum U-values of the building envelope were reduced by approximately 15%, while a maximum shade coefficient for windows was adopted for the first time. The Decree states that, in respect of buildings that are not used as residences, at least 3% of total energy consumption must originate from renewable energy sources. As of 1 January 2017, the U-values for the building envelope were further reduced aiming to have the cost-benefit ratio over the lifecycle of the building reach its cost-optimal level, i.e. close to the NZEB requirements, as laid down in RAA 366/2014.

The minimum percentage of total energy consumption that must originate from renewable sources was also increased significantly both for residential and non-residential buildings. Recently new minimum energy efficiency requirements were announced by the Ministry of Energy that will come into force from 1 July 2020. These will require all residential buildings undergoing major renovation to be energy class A, while all non-residential buildings energy class B+. There will be also specific requirements for hotels.

Industrial sector

In general, Cyprus' energy system has experienced a steady drop in final energy intensity in recent years. Regarding the industrial sector, the energy intensity is rather low as compared to the corresponding values of other EU Member States, due to the nature of the local industrial sector. However, energy efficiency in the industrial sector has improved significantly, as the branch of industry that is subject to the greenhouse gas emissions trading scheme (which consumes approximately 50% of the total final energy consumed by the industrial sector) has now implemented energy-saving measures and uses combined heat and power technology. Nevertheless, there is still a tremendous potential for investments for energy efficiency measures in the industrial sector, since there is an urgent need for individual measures for improvement of their industrial processes equipment.

It is worth mentioning that the industrial sector showed gradual growth over the last decade. In fact, in 2018 the final electricity consumption of the sector was 884 GWh, an increase of 12% from 2009. Although, between 2012 and 2016 the sector has experienced a significant decline due to the economic recession, it is now showing significant signs of recovery. Even the two strongest economic activities of the industrial sector (construction and cement) declined significantly that period (2012-2016) due to the decrease in demand for construction of new buildings[24].

According to data from the Electricity Authority of Cyprus (EAC) for 2017, manufacturing activity contributes 64% of total electricity

[23] Obtained from the report "4th National Energy Efficiency Action Plan of Cyprus" (September 2017)
[24] Obtained from the report "Market Assessment Report for Renewable Energy and Energy Efficiency Small Investments in Cyprus" (October 2019)

consumption in the industrial sector; while the water collection, treatment and supply activity contributes 35%. Out of the total electricity consumption of the manufacturing activity, 30% refers to the manufacture of food products and 39% to the manufacturing of other non-metallic mineral products (e.g. cement, glass and gypsum industry). Other important economic activities are plastics products manufacturing, pharmaceuticals, and the beverage industry in terms of energy consumption.

Residential sector

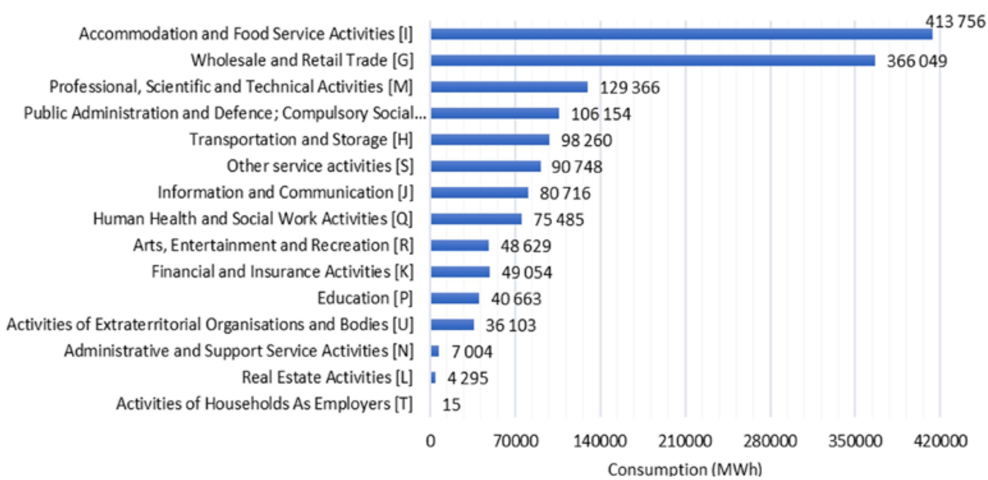
Regarding the residential sector in Cyprus, the energy intensity is lower than the European average level, due to the country's moderate climate; however, it is tending to rise as the population's revenues are increasing and the standard of living improves. There is no doubt, that the residential sector is expected to play a key role in meeting the national energy efficiency targets for 2020 but also for 2030. In Cyprus, 91% of all buildings were built before the introduction of mandatory energy performance requirements, and 50% of them do not have any type of thermal insulation.

The potential for energy efficiency is obvious even from previous support schemes, such as 'save and upgrade', which provided more than € 10 million of public funding for EE in the housing sector. Due to the exhaustion of its funds, this scheme was closed nine months before the predetermined closing date of the scheme. This shows the tremendous interest from house-owners. The scheme funded 50% - 75% of the total investment costs, which means that € 20 million were absorbed by the market in less than a year [25].

Tertiary sector

Similarly, as with the case of the industrial sector, the tertiary sector showed gradual growth over the last decades. The final electricity consumption of the tertiary sector in 2018 was 1.816 GWh, which presents an increase of 61% compared to 1999 levels. As depicted in Figure 5.89, in 2017 'Accommodation and Food Services' appears to be the economic activity with the highest electricity consumption (414 GWh); followed by 'Wholesale and Retail Trade' (366 GWh); the 'Professional, Scientific and Technical Activities' (129 GWh); and 'Public Administration and Defence - Compulsory Social Security' (107 GWh).

Figure 5.89 **Electricity consumption in the tertiary sector in 2017**



Source: CYSTAT, 2017

[25] Obtained from the report "Market Assessment Report for Renewable Energy and Energy Efficiency Small Investments in Cyprus" (October 2019)

It is important to note that the electricity consumptions mentioned in Figure 5.89 refer to aggregate amounts per sector. In order to identify the most energy intensive SMEs in Tertiary sector, the most appropriate performance indicators should be used. As Table 5.105 shows, the ranking of the most energy intense SMEs sectors is as follows: Private hospitals and clinics, private offices, Private schools and hotels.

Table 5.105 **Most energy intense SMEs in the Tertiary sector**[26]

	Tertiary Sector		
SME sectors	**performance Indicator**	**Measurement unit**	**Quantification**
Private Hospitals and clinics	Energy intensity per company - kWhfinal/unit	Energy intensity per company - kWhfinal/unit	3.371
Private office buildings	Energy intensity per company - kWhfinal/unit	kWh/ employee	2.354
Private schools	Energy intensity per company - kWhfinal/unit	kWh/student	306
Hotels and other touristic accommodation	Energy intensity per company - kWhfinal/unit	kWh/guest	44
Retail shops	Energy intensity per company - kWhfinal/unit	kWh/client	6
Restaurants	Energy intensity per company - kWhfinal/unit	kWh/client	3
Airports	Energy intensity per company - kWhfinal/unit	kWh/passenger	3
Sport facilities	Energy intensity per company - kWhfinal/unit	kWh/guest	2,5
Bakeries	Energy intensity per company - kWhfinal/unit	kWh/ client	2
Supermarkets	Energy intensity per company - kWhfinal/unit	kWh/client	2
Coffee shops	Energy intensity per company - kWhfinal/unit	kWh/client	1

Source: Cyprus Employers & Industrialists Federation (OEB)

Concerning the residential buildings, the majority of buildings in the tertiary sector has been constructed without requirements for thermal insulation or any other energy efficiency measures. In fact, the majority (83%) of the building stock of the tertiary sector was built before the first legislation regarding energy performance requirements. In general, it can be assumed that the tertiary sector follows the description of the structure and construction materials of the residential sector, as well as the same period of development. Therefore, there is a huge potential of energy efficiency improvement in the tertiary sector. This potential is particularly high in hotels and for that reason strict minimum energy performance requirements were set from 1 July 2020.

Public buildings

In Cyprus, public buildings are used by central government authorities (Ministries, police, the Attorney General's Office); local authorities; public schools, public universities and other public educational institutions; and the army.

In most public buildings, electricity is used to meet all energy needs, hence implying an average consumption of 130 kWh / m2 per year. In general, almost all public buildings in Cyprus are of low energy efficiency, i.e. their Energy Performance Certificates (EPC) show buildings with energy class C to H. It should be noted that, according to the national legislation all public buildings with a total useful floor area over 250 m2 must have an EPC issued. In addition, according to Article 5 of the Energy Efficiency Directive, there is an obligation to save energy on buildings used by central government authorities at 3,316 GWh per year for the period 2014-2020. According to the MECI, there are 175 buildings (useful floor area over 250 m2) which are owned and used by central government authorities, with a total floor area of 584.202 m2. This number of buildings do not meet the national minimum energy performance requirements. It should be also noted that this number of buildings do not include those except from the minimum energy performance requirements and the requirement to issue an EPC as well as buildings belonging to the armed forces or buildings serving national defence purposes. The Department of Public Works of the Ministry of Transport, Communication and Works, is responsible for the condition and upgrade of the buildings of the central government[27]. Table 5.106 provides an overview of the public buildings with information on their total floor area, number of establishments, average floor area and final electricity consumption per square meter.

Table 5.106 **Timeline of smart meters installation**

	Total floor area (m^2)	Number of establishments	Average floor area (m^2)	Electricity consumption (kWh/m^2 per year)
Tertiary	222.404	N/A	N/A	304
Public	1.886.370	1.087	1.735	75
Secondary	613.546	144	4.261	71
Primary	453.755	325	1.396	65

Source MECI, 2017

Transport sector

The energy intensity in the transport sector of Cyprus is among the highest in the EU, mainly due to the large percentage of road transport operations. However, there has been a remarkable improvement in this sector in recent years. The increase in the energy efficiency of private vehicles and the import of smaller and more efficient cars have led to better results, although public and mass transport in Cyprus are not adequately developed.

Cyprus has the highest car ownership rate in the world with 742 cars per 1.000 people. Other means of transport are very low compared to other countries. According to the Ministry of Transport, 91% of the transportation of Cyprus citizens comes from the use of their own-vehicles, 6% from the use of bicycles or walking and 3% from the use of public transport. In addition, petrol vehicles account for 87% of the total share of vehicles, followed by diesel vehicles with 12% and hybrid and electric vehicles at only 1%.

Cyprus is ranked 24th out of the 28 EU member states for renewable energy use in transport, according to a Eurostat study based on 2017 data (EUROSTAT, 2018). In 2017, the share of energy from renewable sources used for transport in Cyprus stood at 2,6%, compared to the EU average of 7,6%.

The current penetration of alternative fuels in Cyprus is quite low. The amount of biodiesel blend is low as well as the number of electric vehicles on the road. Correspondingly, there is a limited amount of charging points present on the island. LPG vehicles are already in use, but LPG refuelling stations are not yet available. The maritime sector relies entirely on heavy fuel oil and medium distillates[28]. According to current Regulation (R.A.A. 11/2020), the percentage of biofuels that the suppliers of transport fuels (petrol and diesel) are obliged to blend with conventional transport fuel is 7,3%.

According to NECP, more than 1,3 billion Euro of investment is needed for the transport sector until 2030, including investments in infrastructure, changing fleets, etc. Thus, the increase of energy efficiency in the transport sector is considered to be of crucial importance.

(a) National energy efficiency Targets[29]

In the NECP, Cyprus set its indicative contribution to the EU 2030 energy efficiency target as:

27 Information obtained from the MCIT (2017)
28 Obtained from the report "Penetration of alternative fuels in Cyprus road and maritime sectors" (2019)
29 Information obtained from the Cyprus NECP (2020)

5

- Final Energy Consumption of 2,0 Mtoe in 2030, representing 13% reduction in final energy consumption*
- Primary Energy Consumption of 2,4 Mtoe in 2030, representing 17% reduction in primary energy consumption*
- Achieving cumulative energy saving of 243,04 ktoe during 2021-2030

* compared to the respective projection for Cyprus in the 2007 in the EU PRIMES 2007 Reference Scenario

Compared to the EU-wide target of 1.273 Mtoe of primary energy consumption in year 2030, Cyprus is expected to account for 0.21% to the EU wide target for primary energy consumption in 2030, which is higher than its current annual contribution of the EU primary energy consumption.

According to Article 5 of Directive 2012/27/EU that Member States should either renovate annually 3% of the total area of buildings owned and used by central government authorities or choose an alternative approach including other cost-effective energy-saving measures in selected privately-owned public buildings (including, but not limited to, deep renovations and measures to change the behaviour of users), in order to achieve by 2020 an equivalent amount of energy savings. Since the alternative approach gives more flexibility in implementing cost-effective energy saving measures as appropriate, Cyprus has chosen this alternative approach. It has been estimated that annual energy savings of 3,316 GWh or 0,285 ktoe have to be achieved for the period 2014-2020.
The same approach will be followed for the period 2021 - 2030, though the annual energy saving obligation that has been recalculated based on the modifications of public building stock. The new annual energy saving obligation for the period 2021 - 2030 is 1,31 GWh or 0,11 ktoe. It has to be noted that the proposed minimum energy performance requirements will require minimum energy class B+ for major renovation of non-residential buildings.

The obligation for the period 2021 - 2030 is scheduled to be fulfilled mainly with the following measures:

1. Deep renovations: Proposal to secure funds from European Cohesion and Development Funds, for the period 2021 - 2027
2. Individual target measures: Measures identified as cost optimum as well as measures combined with maintenance works will be undertaken by the Department of Public Works and the Department of Electromechanical Services mainly funded by national funds.
3. Behavioural measures: The Energy Saving Officer appointed in every public building is entitled to record energy consumption and promote energy efficiency mainly with soft measures. He/she plays a central role in change occupants' habits towards a more rationale use of energy.

Moreover, according to article 6 of Directive 2012/27/EU, the central government is obliged to buy and rent only buildings that at least comply with the minimum energy efficiency requirements. It expected that this measure will change the situation where central government is a tenant in many buildings of poor energy performance.

Finally, a mandatory target was set aiming the improvement of the energy efficiency of the building stock: By 31 December 2020, all new buildings must be nearly zero energy buildings, while this obligation for the public buildings is already in force from 31 December 2019.

(b) Incentive-based Initiatives in the Building Sector

The building sector in Cyprus consumes more than 35% of the total need for energy. On the basis of surveys undertaken by the Energy Service, as well as from the experience gained from the operation of various Grant Schemes, the potential for energy savings in the residential sector through the implementation of proper thermal insulation measures is significant, ranging between 25% and 50%, as the case may be.

A long failure to adopt compulsory thermal insulation regulations for new buildings in Cyprus has resulted in the construction of a large number of buildings of poor to average thermal performance that need increased amounts of energy for maintaining a desired level of comfort. Implementing the Energy Performance of Buildings Directive and the Energy Efficiency Directive is expected to make a significant contribution towards energy savings in the building sector. In addition to thermal insulation, another important field where energy can be saved in buildings is that of heating and cooling systems, regular maintenance of which can ensure substantial energy and environmental benefits[30].

Several studies conducted on behalf of the Energy Service (MECI) have shown that the most cost-effective measures to improve the energy efficiency of existing buildings are:
• Roof thermal insulation
• Heat pumps
• Solar thermal systems for DHW
• LED lighting
• PV systems
• Biomass boilers

Table 5.107 presents the mean payback periods of energy efficiency measures in two main types of residential buildings in Cyprus.

Table 5.107 **Mean payback periods of EE measures in two main types of residential buildings in Cyprus[31]**

	Single Family Houses Payback period (years)	Multi Apartment Buildings Payback period (years)
Deep renovation (to nZEB)	30,7	25,6
Roof insulation	3,6	2,3
Façade insulation	46,1	19,7
Ground level insulation		27,0
Upgrade of window frames	58,6	31,5
Electronic appliances & lighting	8,6	7,3
Heat pump	5,2	6,3
Solar thermal system for hot water production	4,9	4,9

Source MECI, 2017

Over the last years, the government of Cyprus has developed various support schemes and incentives for energy efficiency and RES in order to further support GHG emissions reductions. The majority of these schemes/ instruments are intended to be financed by the national budget, some with assistance from EU funds. The national support schemes that are currently in place for energy efficiency improvement are:

Roof thermal insulation

For owners of existing private residential buildings, a grant scheme for roof top thermal insulation is available. The grant covers 30% of the eligible costs per application, with a maximum grant amount of €1.500.

Further, for thermal insulation of the roof in combination with the installation of PV net-metering systems (residential buildings), an additional grant scheme is available: Regarding the PV system, grants cover € 300 / installed kW; regarding roof insulation, 35% of the eligible costs per application can be covered. The maximum grant amount for the PV system is € 1.200 and € 1.800 for the thermal insulation. Therefore, the maximum grant amount per application is € 3.000.

Solar thermal systems for DHW

For the installation or replacement of solar water heating systems in residential buildings there is a grant available through the Fund for RES & EE (governmental support), namely at € 350 per dwelling and per beneficiary. Furthermore, for solar panels with solar Keymark certification, the grant amount is € 350. For the replacement or installation of solar panels, the maximum grant amount is € 175 per dwelling and per beneficiary.

Energy Audits

The grant scheme for energy audits in SMEs was in place by May 2019, with a total available

[30] Obtained from the report "4th National Energy Efficiency Action Plan of Cyprus" (September 2017)
[31] Obtained from the report "Determination of Cost-Effective Energy Efficiency Measures in Buildings with the Aid of Multiple Indices", (2017)

budget of € 200.000. This government endorsed grant will supplement 30% of the costs of an energy audit, up to a maximum of € 2.000. The scheme is expected to be utilised by 100 SMEs across the country. Based on oral information from MECI, there is no interest from potential applicants on this scheme. Reasons could be that the energy audit a) is not obligatory for SMEs, b) there is no grant scheme or other financial instruments to support SMEs to materialise the investments.

Eco-Management and Audit Scheme (EMAS)

This scheme aims at increasing the environmental performance of SMEs through the establishment of an environmental management system as foreseen in Regulation 1221/2009 / EC. It concerns the provision of subsidies to enterprises that intend to establish an Eco-Management and Audit Scheme (EMAS). It aims to address the environmental impacts of SMEs, as well as to reduce the use of natural resources and improve their energy performance.

The scheme is based on de minimis aid and provides 70% of the cost of providing services for the establishment of an environmental management system with a maximum grant amount of € 2.000. It is also available for the verification and validation of the system with a maximum grant amount of € 500. Transition Costs from ISO 14001 to EMAS can also be funded through additional grants of € 500.

(c) EU Funded (or otherwise funded) Energy Efficiency Programmes

Funds amounting to €53 million have been secured through the European and Structural Funds 2014-2020 Programme, in order to operate schemes and materialize projects, to improve the energy efficiency of existing households, enterprises and public buildings, as well as for pilot projects for high efficiency combined heat and power generation. Funds have also been secured for materializing measures towards sustainable transportation in the period 2014-2020.

As part of the National Operational Programme "Competitiveness and Sustainable Development 2014-2020", the Directorate General for European Programmes Coordination and Development (DG EPCE), acting as Managing Authority (MA), has dedicated resources to the implementation of an Energy Fund of Funds (EnergyFoF) managed by European Investment Bank. The financial product that will be offered through the EnergyFoF is loans to legal or natural persons to materialise investments that aiming to increase the energy efficiency.

The Energy FoF targets in accelerating clean energy investments, including energy efficiency improvements, renewable energy and sustainable urban development projects. Investment to improve energy efficiency in public and private buildings, including SMEs. The Energy FoF is co-financed by European Structural and Investment Funds (ESIF) (€ 40 million), national funds as a national loan from EIB (€ 40 million) and the participated financial intermediaries (€ 40 million). Thus, the total allocated initial amount of EnergyFoF for the period 2020-2023 is €120 million.

The funding will be allocated to the following Special/Thematic Objectives:

- Promotion of entrepreneurship in specific population groups enhancing access to finance. (€10.000.000)
- Increase energy savings in SMEs. (€14.200.000)
- Increase energy savings in public buildings (€7.900.000)
- Increase energy savings in households (€7.900.000)

Upon a successful operation of the fund, it will be used after 2023 in order to continue its operation, utilizing the resources that will be returned to the fund. The establishment of a revolving fund "the Energy Fund of Funds providing soft loans for energy efficiency" is the first step towards a more market-oriented financial support scheme. The success or not of this fund is closely associated with the involvement and cooperation with the domestic banking sector.

(d) Cogeneration: Regulatory Framework, Installed Capacity

Included in the category of net-billing are the combined heat and power (CHP) units, which can be found in any commercial or industrial premises (e.g. commercial or industrial units, public buildings, camps, schools, agricultural and livestock units). The installed power of each CHP system cannot exceed 5MW per installation and the total power for all units allocated to this scheme is 20MW. Until now, there is no interest for this scheme as the tariff regime is bit

(e) Planned policies and New Major Projects for energy efficiency

The table below shows some of the policies and measures that are planned to be implemented during the period 2021 - 2030, in order to contribute to achieving the energy efficiency target for 2030.

Table 5.108 **Planned policies and measures for energy efficiency**

a/a	Policy/Measure	Sector(s) affected
1.	The government is examining a fiscally neutral green tax reform, which can significantly contribute towards transition to an economically and environmentally sustainable development. This is expected to lead to energy savings and will notably reduce the energy dependency of Cyprus.	Agriculture, Industry, Service, Transport, Households, Energy supply
2.	Implementation of the Energy Fund of Funds which will provide soft loans for energy efficiency	Agriculture, Industry, SMEs Public sector, Households
3.	Voluntary commitment from businesses to reduce their emissions by more than 8% by 2030 under the "Business for climate" initiative. It includes specific commitment for improving their energy efficiency.	Agriculture, Industry, Service
4.	Additional floor space "allowance" for new buildings and buildings that are renovated. It is possible to increase the building rate by 5% for energy class A building, and primary energy consumption will not exceed 50 (kwh / m2 year). The aim is to incentivize the construction or renovation of buildings that go beyond NZEB requirements.	Agriculture, Industry, Service, Households | Buildings
5.	Templates and standard procedures for energy performance procurement in public sector will be prepared and disseminated to all public authorities.	Service (Public Sector)
6.	Targeted training and other events to be provided to selected target groups, involved in energy efficiency (implementation and financing).	Agriculture, Industry, Service, Transport, Households, Energy supply
7.	Individual energy efficiency interventions and energy efficiency retrofits in selected governmental and municipal buildings through project funding and Interreg projects CYPRUS-GREECE	Service (Public Sector)
8.	Implementation of individual measures in the building shell, in heating and cooling equipment and energy efficiency retrofits, based on energy performance certificate.	Service (Public Sector)
9.	Implementation of net-billing scheme to commercial/industrial and public administration consumer categories for the installation of high efficiency cogeneration HECHP systems with the prime goal of covering their own consumption.	Industry, Service
10.	Pilot projects (General hospital of Nicosia and the University of Cyprus) for installing high efficiency cogeneration in public buildings.	Service (Public Sector)
11.	Energy efficiency obligation in public purchases and national green public procurement action plan	Service (Public Sector)
12.	Implementation of soft measures (information campaigns, trainings, workshops, etc).	Agriculture, Industry, Service, Households Buildings

a/a	Policy/Measure	Sector(s) affected
13.	Replacing existing lamps / lighting fixtures lighting systems in public roads with new, more efficient ones. The measure concerns the replacement of existing lamps with more efficient ones in the national highway that is under the responsibility of Department of Electromechanical Services, as well as, in local roads that are under the responsibility of the municipalities	Service (Public Sector)
14.	Energy efficiency in electricity infrastructure. This measure aims to decrease system losses and lead to substantial energy savings in the distribution system by upgrading the medium nominal voltage of 11kV to 22kV.	Electricity Sector
15.	Increase of energy efficiency in electricity generation due to the increase of efficiency and the switching of the fuel to natural gas	Electricity Sector
16.	Development of efficient district heating and cooling infrastructure based upon RDF fired cogeneration technologies in tourist areas.	Electricity Sector
17.	Promotion of measures i in water sector (including production, cleaning, pumping, desalination etc) that will achieve end use savings	Service sector, defence sector and industry
18.	Installation of 400,000 electricity smart meters on building stock of the country between the period 2021-2027	Agriculture, Industry, Service, Households
19.	Incentives for the purchase and use of low/zero emission vehicles including the old vehicle scraping scheme and financial incentives for the purchase of electric vehicles.	Transport sector
20.	Installation of charging points and infrastructures for electric vehicles	Transport sector
21.	Specific requirements will be included within the new bus operators' contract such as: • Additional Cost for the Tenderer to Convert their bus fleet to Compressed Natural Gas (CNG), when such fuel source is available in Cyprus and the prerequisites for doing so exist. • Additional Cost for the Tenderer to provide Electric Buses (maximum capacity 22 persons) in Historic City Centres	Transport sector
22.	Installation of telematic system in public bus fleet in order to record data for further optimisation of the public transport system.	Transport sector
23.	Shift of modal share from car trips to sustainable modes of transport - Implementation of Sustainable Urban Mobility Plans including: • Significantly improved bus service (routes, frequency, hours of operation) • Upgrading of infrastructure for pedestrians, cyclists and public transport • Development and implementation of a holistic parking policy Configuration of zero or low emission zones Promotion of a tram system in Nicosia • Development and implementation of high-quality public transport corridors for other cities	Transport sector
24.	Use of vehicles with low or zero emissions	Transport sector

Source: MECI

Energy Legislation & Regulatory Framework

Cyprus has extensive legislation covering the fields of petroleum fuels, the power generation market, natural gas market, hydrocarbons prospection, exploration and exploitation, and the promotion of Renewable Energy Sources. This legislation is summarized as follows:

Renewables

The Energy Service of the Ministry of Energy Commerce and Industry is promoting projects for solar energy (solar-thermal and PV), wind energy (for electricity generation), geothermal energy and biomass-derived energy (for heating and electricity generation), including biofuels, through Law 112(I) 2013 and its subsequent amendments and complimentary Regulations and Ministerial Orders. In addition to the various tasks entrusted to the Energy Service and under section 3 of the Application of European Regulations in the Field of Energy Law 278(I) of 2004, the Energy Service has been nominated as the competent authority for the purpose of implementing the relevant EC regulations which are applicable in Cyprus. Table 5.109 presents the Cyprus regulatory framework regarding Renewable Energy Sources.

Table 5.109 **Legislation and regulatory framework for RES**

Laws	• Law 112 (I) / 2013 - on the promotion and encouragement of the Use of RES
	• Law 157 (I) / 2015 - on the promotion and encouragement of the Use of RES (amending Law)
	• Law 62 (I) / 2018 - on the promotion and encouragement of the Use of RES (amending Law)
Regulations	• R.A.A. 374/2015 - on the promotion and Encouragement of the Use of RES (Certification of Installers for Small scale RES Systems)
	• R.A.A. 248/2015 - on the promotion and Encouragement of the Use of RES (Urgent Fee Calculation Methodology (Annulled)
	• R.A.A. 375/2016 - on the Promotion and Encouragement of the Use of RES (Determination of the Consumption Fee)
Decrees	• R.A.A. 25/2017 - on the promotion and Encouragement of the Use of RES (Criteria to be met by the training providers and the examination bodies regarding the Installers for Small scale RES Systems)
	• R.A.A. 26/2017 - on the promotion and Encouragement of the Use of RES (Examination of Installers for Small scale RES Systems)
	• R.A.A. 211/2018 - on the Promotion and Encouragement of the Use RES (Methodology for Calculating the Share of Energy from Renewable Sources).
Council of Ministers Decision	• No. Decision 78.656 - Abolition of support schemes that provide a guaranteed subsidy price for RES electricity projects and the inclusion of these projects in the competitive electricity market.

Source: EAC

Electricity

By virtue of Part II of the Electricity Market Regulation Law 122(I) of 2003, as amended, (the Electricity Law) the Cyprus Energy Regulatory Authority (CERA) was established as an independent governmental authority with regulatory powers in the energy field, especially the electricity and natural gas sectors. The Electricity Authority of Cyprus (EAC) was established under the provisions of the Development of Electricity Law, Cap. 171, and until the accession of Cyprus to the EU, it had the monopoly for the generation and supply of electricity throughout the island. The liberalisation of the electricity market began with the enactment of the **Electricity Market Law**, which transposed EC Directive 2003/54 into national law. The aforementioned law provides for the regulation of the electricity market of the Republic and, among other things[32] :

- Establishes the Regulatory Authority of Energy of Cyprus (CERA).
- Provides for the creation of a new licensing regime in respect of the generation, transmission, distribution and supply of electricity.
- Establishes the framework for the arrangements between the Transmission System Owner and the Transmission System Operator.

[32] Obtained from EAC (https://www.eac.com.cy/EN/RegulatedActivities/Transmission/legislation-regulations/Pages/default.aspx)

- Regulates access to the transmission system and the distribution system.
- Allows for provision to be made in respect of Public Service Obligations.
- Regulates issues concerning consumer protection.

According to paragraph (1) of article 34 of the Electricity Market Law, any person to carry out any of the following activities related to electricity must be first licensed by the Cyprus Energy Regulatory Authority (CERA):
- Construct a power station or generate electricity
- To supply electricity to eligible customers
- To supply electricity to non-eligible customers
- To carry out any of the responsibilities of the Transmission System Operator in accordance with Article 60
- Perform any of the responsibilities of the Distribution System Operator in accordance with Article 53
- Perform any of the functions of the Transmission System Owner in accordance with Article 46; or
- Perform any of the responsibilities of the Distribution System Owner in accordance with Article 51.

According to paragraph (2) of Article 35, CERA may grant an Exemption from License for the activities referred to in paragraphs (a) and (b) of subsection (1) of Article 34, under such terms and conditions determined by CERA. An exception may be granted for:
- Production of electricity for own use up to 1MW
- Production of electricity from renewable energy sources up to 5MW, or
- Electricity supply by a specific person, the total power of which does not exceed 0,5MW for each plant.

According to paragraph (1) of Article 37, any Application for Submission shall be submitted to CERA in accordance with the rules provided in the Licensing Regulations[33].

Subject to any relevant Ministerial Orders on governmental policy, according to section 38 of the Electricity Law, inter alia, a number of criteria must be taken into consideration objectively and without discrimination by CERA when examining a licence application, which include amongst others:
- The safety of the electricity system, the production facilities and the electricity cable lines.
- The protection of the environment.
- The location of the power stations and the use of land.
- The efficient use of energy.
- The nature of the primary energy source.
- The technical and financial capabilities of the applicant.

Transmission System Operator

The Transmission System Management Unit (the Transmission System Operator or TSO) has been established under section 58 of the Electricity Law. The TSO must ensure, on the basis of objective criteria, that proper allocation of the load and use of the transmission system is made under the licenses, the Rules of Transmission and Distribution or the Electricity Market Rules, and that the operation and management of the electricity trade is compatible with the Electricity Market Rules pursuant to sections 62 (f) and (g) of the Electricity Law.

[33] Obtained from CERA (https://www.cera.org.cy/en-gb/ilektrismos/1169/ilektrismos-adeiodotisi)

Co-Generation

The Laws on the Promotion of Energy Efficiency in Heating & Cooling and co-generation of electricity & heat from 2006 to 2015, through which Article 14 of Directive 2012/27/EU was enacted to national legislation, expand its scope and replace the provisions of Directive 2004/8/EC (for the promotion of electricity and heat co-generation). The new Law amendments aim at the identification and improvement of energy efficiency in the heating and cooling sector through the introduction of binding measures.

Petroleum Products

Petroleum issues are covered by the Petroleum Law, Cap. 272, and the Law on the Specifications of Petroleum Products and Fuels, 148(I) of 2003, and their subsequent amendments (40(I)/2007, 12(I)/2009, 111(I)/2013, 37(I)/2015, 24(I)/2018) we well as the Ministerial Degrees. The Petroleum Law deals with the licenses required and the regulations for the storage of petroleum products. The Law on the Specifications of Petroleum Products and Fuels requires various oil products to meet certain specific standards. These standards are set by Ministerial Orders that rely on specifications adopted at EU level under EU Directives. Specifications on health and environmental matters are included in those Directives, as well as lower limits for the sulphur content of heavy fuel oils and gas oil. Pursuant to sections 5-10 of Law 148(I) of 2003, as amended, the quality of fuel is supervised by the Energy Service through market surveillance by inspectors, the designation of appropriate testing laboratories, the setting of sampling methods and the collection and analysis of the relevant data. Recently various Ministerial Degrees have been adopted in order to meet the national biofuels target (emissions and energy content).

Natural Gas

As initially required by EC Directive 2003/55 Cyprus passed the Natural Gas Market Regulation Law, 183(I) of 2004, as amended (The Law on the Regulation of the Natural Gas Market of 2004 was amended by Laws 103 (I) / 2006, 199 (I) / 2007, 219 (I) / 2012 and 148 (I) / 2018), which constitutes the main legal framework for the regulation of all aspects of the Cyprus natural gas market. In late 2012 amendments were effected, when the national legislation for harmonising with the requirements of the Gas Directive 2009/73/EC.

Transmission, Storage and LNG Facilities

Under section 16 of Law 183(I) of 2004, as amended, undertakings which own facilities connected with the transmission or storage of natural gas, or LNG facilities, are obliged to appoint at least one system operator who is responsible for the operation, maintenance and upgrading of such facilities.

Distribution of Natural Gas

Pursuant to sections 21 and 22 of Law 183(I) of 2004, as amended, undertakings that own distribution systems are required to appoint one or more distribution system operators whose overall task includes operation, maintenance and development under economically viable conditions of a safe, reliable and efficient distribution system, taking into consideration the protection of the environment.

Prospecting ,Exploration and Production

The Hydrocarbons (Prospection, Exploration and Exploitation) Law 4(I) of 2007 (the Hydrocarbons Law) regulates the prospecting, exploration and exploitation of hydrocarbons in conformity with EC Directive 94/22. Furthermore, a Strategic Environmental Assessment (SEAReport) concerning Hydrocarbon Activities within the Exclusive Economic Zone of the Republic of Cyprus was published in November 2008 in accordance with the Assessment of Impact on the Environment of Certain Plans Law 102(I) of 2005. The results and guidelines of the SEA must be respected/followed by all licenses operating in hydrocarbon activities within the Cypriot EEZ. The Regulation on safety of offshore oil and gas operations (no. 424 of 2015) implements the EC Directive 2013/30 and appoints the Department of Labour Inspection as competent authority under this Regulation.

Retail Fuels Pricing

The Petroleum (Establishment of Maximum Retail Pricing in Extraordinary Cases) Law, 115(I) of 2004, as amended (Law 57(I)/2010), provides that the retail price of petroleum products is freely set by the petroleum companies and the petrol station operators, taking into consideration the prevailing international and domestic market conditions. It also gives powers to the Minister of Energy, Commerce & Industry to set ceilings to retail fuels prices on some or all petroleum products for a period of 45 days, whenever the Minister has good reasons to believe that the level of petroleum products prices supplied in the market is excessively higher from what can be justified based on international and national (domestic) conditions in force.

Efficiency and Energy Conservation

Under section 4 of the Regulation of Energy Efficiency of Buildings Law, 142(I) of 2006, as amended, each new building and every building that is substantially renovated must comply with the minimum energy efficiency requirements specified by the relevant Ministerial Order. Moreover, through the Energy Efficiency Law 31(I) of 2009, as amended, Cyprus implemented the 2012 Energy Efficiency Directive, which establishes a set of binding measures to help the EU reach its 20% energy efficiency target by 2020.

Further information on Cyprus's energy legislation framework and regulatory regime you may find in Chapter 8.

5

GREECE

Greece

Economic and Political Background

Greece's GDP contracted at a slower, albeit still pronounced, pace of 7.9% in the final quarter of last year (Q3 2020: -10.5% y-o-y), as the country's second lockdown imposed in early November weighed on activity. All in all, GDP tumbled 8.0% in 2020, contrasting 2019's 1.6% growth and logging the worst downturn since 2011.

Private consumption fell 4.7% in annual terms in Q4 2020, worsening from Q3's 1.6% contraction, as the closure of non-essential businesses for most of the quarter hindered household spending. Meanwhile, fixed investment rebounded, growing 1.6% in Q4 and contrasting the 1.1% decline tallied in the prior quarter. Moreover, government consumption picked up, expanding 7.3% in Q4 (Q3: +4.8% y-o-y).

On the external front, exports of goods and services slid 13.4% in the fourth quarter, softening significantly from Q3's 41.9% nosedive. Conversely, imports of goods and services declined at a more pronounced pace of 9.5% in Q4 (Q3: -5.8% y-o-y). Lastly, on a seasonally-adjusted quarter-on-quarter basis, economic growth moderated to 2.7% in Q4 from 3.1% in the previous quarter.

The economic scenario has likely remained frail in the first quarter of the new year, weighed on by the continuous extension of localized lockdowns throughout Q1. However, the recovery is seen picking up pace from Q2 as national and global vaccine efforts progress, enabling the lifting of local restrictions and kickstarting the all-important tourism industry. However, much hinges on the pace of vaccination and the course of the pandemic, with new Covid-19 variants and the possible extension of restrictions posing key downside risks. IMF estimates that Greece's GDP will expand by 4.1% in 2021, significantly higher than -9.5% in 2020.

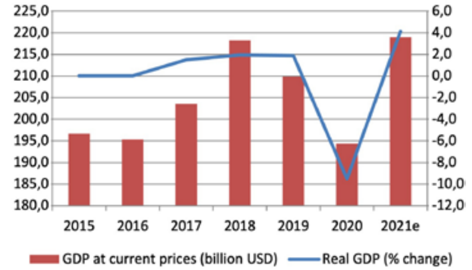
Over the course of March 2021, the Greek government announced a series of policy measures to mitigate the severe economic impact of the coronavirus outbreak. On March 19, after previously receiving the green light from creditors to suspend the 3.5% primary fiscal target for this year, Prime Minister Kyriakos Mitsotakis announced that the government would mobilize a total of around €10 billion in a combination of state resources and EU structural funds to help households and businesses cope with the unprecedented crisis imposed by Covid-19.

The measures, which have been unveiled in succession as time progressed, include a one-off €800 payment to workers that have been laid off due to business closures and to those whose employers suffer large financial losses; temporary suspension of tax and social security obligations for affected businesses; a reduction of VAT on certain pharmaceutical products; and tax deferrals for workers and the self-employed.

The government indicated that additional measures were also being contemplated. Meanwhile, in a major move that has come to provide key additional support, the ECB's €750 billion emergency asset purchase scheme unveiled on 18 March included Greek bonds for the first time since the country's sovereign debt crisis. Having been locked out of previous ECB QE operations due to the country's below-investment grade rating, the inclusion of around €12 billion of Greek bonds are expected to ease fiscal pressure somewhat by lowering borrowing costs.

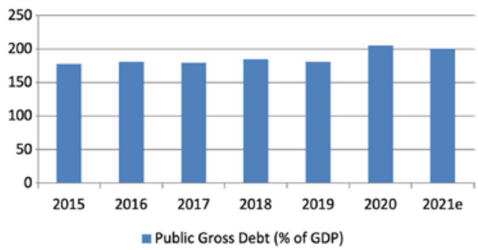
Nevertheless, the outlook has turned bleak. In particular, the vital tourism industry, which has become the engine of the economy and accounts for about a fifth of employment and output, is set to take a massive hit amid plunging bookings, travel restrictions and business closures. Additionally, with economic activity screeching to a halt, this in turn could exacerbate fragilities in the banking system which is already burdened by the highest non-performing loan ratio in the Eurozone.

Figure 5.90 **Greece's GDP and its annual GDP growth**



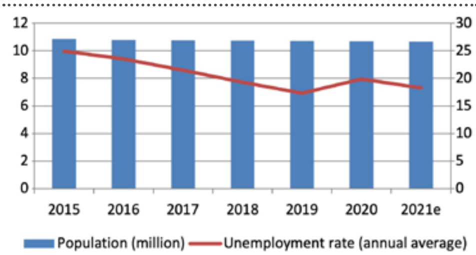
Source: IMF World Energy Outlook (October 2020)

Figure 5.91 **Greece's Public Gross Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.92 **Greece's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy

Greek energy policy is formulated at central government level by the Ministry of Environment and Energy, which is in charge of overall policy formulation. The Greek Energy Policy can be summarized as follows:

- Identify and develop indigenous energy resources in order to ensure the secure, sustainable and constant supply of the country's energy needs.
- Maintain adequate oil and lignite supplies and develop stocks, alternative import sources and routes in order to meet the needs of the domestic energy market at times of crisis.
- Promote the penetration of Renewable Energy Sources in the country's final energy mix, while increasing its overall energy efficiencies and limit its dependence on the utilization of oil and lignite.

Greece's strategy is achieved by establishing and improving the necessary regulatory framework, which focuses on the following:

- Development of alternative energy sources
- Construction of oil, natural gas and electricity interconnectors
- Increased utilization of domestic energy resources and reserves
- Decrease dependence on imported energy sources while building international partnership to mitigate their associated political risks
- Development of renewable energy resources
- Promote the utilization of clean, efficient and environmental friendly technologies
- Enhance the liberalization of the electricity and natural gas markets
- Encourage investments in power generation, upstream oil and gas exploration and midstream infrastructure investments
- Increase energy efficiency in the industrial, transport and residential sector.

Governmental Institutions

The main institutions in the Greek energy sector are the following:

- The **Ministry of Environment and Energy** is principally responsible for the formulation and implementation of the Greek energy policy in the wider context of the country's European and international obligations on the environment and the combat of climate change.
- The **Regulatory Authority for Energy (RAE)** is the independent authority that promotes and safeguards the liberalization of the country's natural gas and electricity markets. Its main responsibility is to supervise the domestic energy market in all sectors, making suggestions to the competent institutions.

- The mission of the **Independent Power Transmission Operator (IPTO or ADMIE)** is the operation, control, maintenance and development of the Hellenic Electricity Transmission System, to ensure the country's supply with electricity in an adequate, safe, efficient and reliable manner, as well as the operation of the electricity market for transactions outside the Day Ahead Scheduling, pursuant to the principles of transparency, equality and free competition.
- The **Public Power Corporation (PPC)** is the leading power generation and supply company in Greece engaged in the generation, distribution and sale of electricity to consumers. Its total installed capacity in Greece is 12.2 GW, with thermal and hydroelectric power plants as well as Renewable Energy Sources (RES) installations both on the mainland and the islands. It is the owner of the power distribution network with Regulated Asset Base of approximately €3 billion, which is operated by its subsidiary company HEDNO S.A. Moreover, it is the largest power supplier with approximately 6.9 million customers all over the country.
- The **Hellenic Electricity Distribution Network Operator (HEDNO)** was formed by the separation of the Distribution Department from PPC S.A. Although it is a 100% subsidiary of PPC, it is independent in operation and management. HEDNO's tasks include the operation, maintenance and development of the power distribution network in Greece, as well as the assurance of a transparent and impartial access of consumers and of all network users in general.
- The **Hellenic Gas Transmission System Operator (DESFA)** is responsible for the operation, management, utilization and development of the National Natural Gas System and its interconnections, in a technically sound and economically efficient way, in order to best serve its Users with safety, reliability and adequacy. Contributing decisively to the security of supply and the diversification of supply sources of the wider region, DESFA also facilitates the development of competition in the Greek energy market, while systematically striving for the reduction of greenhouse gas emissions.
- The **Public Gas Corporation (DEPA)** is a group of companies with presence in the energy sector, actively engaged in the wholesale market, trading, supply and distribution of natural gas. The Hellenic Republic Asset Development Fund (HRADF) holds 65% of DEPA S.A. and Hellenic Petroleum S.A. the remaining 35%.A partial demerger of DEPA's distribution gas activities has already taken place (these activities were transferred to a new legal entity which is named DEPA Infrastructure S.A.). Also, DEPA's participations in international projects were transferred through a spin-off to a new legal entity which is named DEPA International Projects S.A. Following the completion of the partial demerger and spin-off, all current wholesale and retail gas activities of DEPA remain under DEPA under the name of DEPA COMMERCIAL S.A.
- **Hellenic Hydrocarbon Resources Management (HHRM)** was established in 2011 and is headquartered in Athens. It is a state-owned company with the Hellenic State being the sole stakeholder (100%); however, it operates independently as a private-sector economic entity. HHRM is a rapidly growing company providing an innovative and effective management in a wide spectrum of activities: Exploration & Production concessions, overview of the signed lease agreements, offshore safety, and active promotion of Greece as an attractive oil and gas destination to international investors.
- **Renewable Energy Sources Operator & Guarantees of Origin (DAPEEP)** is responsible for renewable energy markets of Greece's National Interconnected System (Transmission System and Distribution Network of Mainland and Interconnected Islands). The company also manages the Guarantees of Origin of Electricity from RES and Combined Heat and Power Units (CHP). DAPEEP is also the auctioneer of the CO_2 Emissions Allowances in Greece, while at the same time operates as the Aggregator of Last Resort (FOSETEK) of RES producers.
- The **Hellenic Energy Exchange (HEnEx)** manages the energy markets of physical delivery and the energy financial markets in accordance with the provisions of Law 4512/2018 and its delegated acts.

Energy Demand and Supply

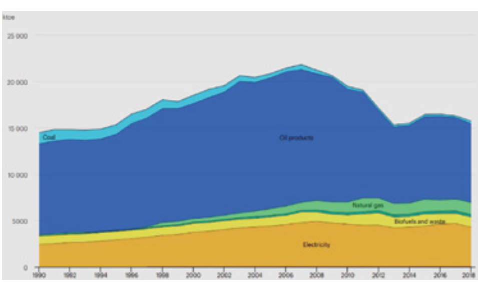
From the early 1990s until now, the Greek energy system has developed in line with the requirements of the national economy, the evolution of other economic activities and the growth of specific sectors, affecting consumer habits, but also European policies on energy, the environment and growth.

National Energy Demand

In the total energy system, domestic final energy consumption was at 15,735 kilotons of oil equivalent (ktoe) in 2018, down 3.5% from 2017. Figure 5.93 depicts the share of the various fuels in final energy consumption over the period 1990-2018. Oil products account for the largest share in final use consumption (54.2% in 2018), followed by electricity (27%), RES (8.7%), natural gas (8.3%) and lignite (1.8%).

The consumption of fossil fuels in final use, namely petroleum products, lignite and natural gas, decreased considerably in 2018 compared to consumption levels in 2007, falling by 36%. This reduction was to a large extent balanced by consumption of natural gas, the use of RES and electricity. Indicatively, consumption of natural gas rose by approx. 54% to 1,297 ktoe in 2018 as compared to 2007. Over the same period, the shares of oil products and lignite were reduced by 41% to 8,493 ktoe and by 47% to 282 ktoe respectively.

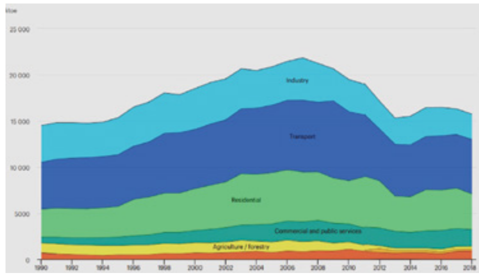
Figure 5.93 **Final Energy Consumption by Type of Fuel in Greece, 1990-2018**



Source: IEA

2018, the largest drop was in the industrial sector, a decline of approx. 40% to 2,739 ktoe, followed by the residential sector and transport, a decline of 29% to 3,845 ktoe and of 24% to 5,897 ktoe respectively in final energy consumption, as compared to 2007.

Figure 5.94 **Final Energy Consumption by Sector in Greece, 1990-2018**

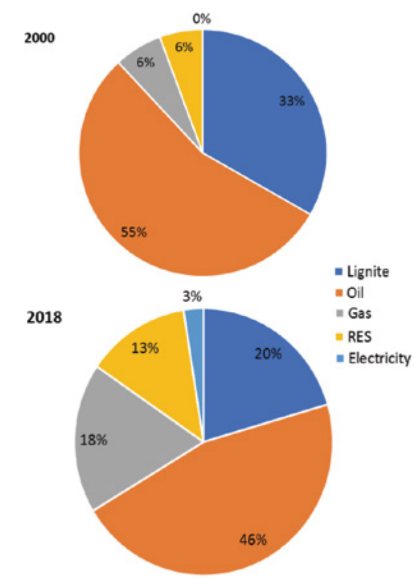


Source: IEA

National Energy Supply

Concerning Greece's total primary energy supply, IEA data for 2018 indicate that oil and oil products account for 46%, followed by lignite (20%), natural gas (18%) and RES (13%), as shown in Figure 5.95. In 2018, the total primary energy supply in Greece stood at 22.6 Mtoe, compared to 27.1 Mtoe in 2000

Figure 5.95 **Total Primary Energy Supply in Greece, 2000 and 2018**

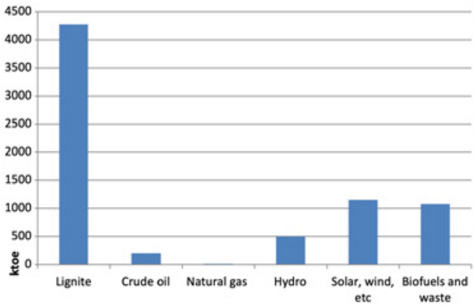


Source: IEA

Energy Balance

Domestic primary energy production decreased from 9.4 Mtoe in 2010 to 7.2 Mtoe in 2018, with substantial fall on the contribution of lignite and important increase in RES use. Lignite remained the country's main source of indigenous energy, accounting for more than 59% of energy production in 2018. It should also be noted that the contribution of biofuels and waste reached about 15% of energy production, while the share of renewables increased from 15.17% in 2000 to 37.76% in 2018.

Figure 5.96 **Energy Production in Greece, 2018 (Total=7,211 ktoe)**



Source: IEA

Table 5.110 **Energy Balance for Greece, 2018**

Ktoe on a net calorific value basis	Coal*	Crude oil*	Oil products	Natural gas	Nuclear	Hydro	Geothermal, solar, etc.	Biofuels and waste	Electricity	Heat	Total**
Production	4275	201	0	13	0	494	1154	1075	0	0	7211
Imports	234	30032	3663	4145	0	0	0	142	735	0	38952
Exports	0	-215	-20130	0	0	0	0	-18	-195	0	-20558
International marine bunkers***	0	0	-2185	0	0	0	0	0	0	0	-2185
International aviation bunkers***	0	0	-1089	0	0	0	0	0	0	0	-1089
Stock changes	196	-19	99	-40	0	0	0	1	0	0	236
TPES	**4705**	**30000**	**-19642**	**4117**	**0**	**494**	**1154**	**1199**	**540**	**0**	**22566**
Transfers	0	2312	-2291	0	0	0	0	0	0	0	21
Statistical differences	-14	-9	144	-32	0	0	0	2	0	0	90
Electricity plants	-2693	0	-1089	-2493	0	-494	-868	-21	3798	0	-3860
CHP plants	-1716	0	-219	-200	0	0	0	-103	781	52	-1406
Heat plants	0	0	0	0	0	0	0	0	0	0	0
Gas works	0	0	0	0	0	0	0	0	0	0	0
Oil refineries	0	-32302	33085	0	0	0	0	0	0	0	782
Coal transformation	0	0	0	0	0	0	0	0	0	0	0
Liquefication plants	0	0	0	0	0	0	0	0	0	0	0
Other transformation	0	0	0	0	0	0	0	-1	0	0	-1
Energy industry own use	0	0	-1494	-86	0	0	0	-3	-414	0	-1996
Losses	0	0	0	-10	0	0	0	0	-451	0	-461
TFC	**282**	**0**	**8493**	**1297**	**0**	**0**	**286**	**1072**	**4254**	**52**	**15735**
Industry	277	0	931	321	0	0	2	141	1067	0	2739
Transport	0	0	5706	15	0	0	0	159	17	0	5897
Other	2	0	1496	357	0	0	205	875	3196	42	6173

Ktoe on a net calorific value basis	Coal*	Crude oil*	Oil products	Natural gas	Nuclear	Hydro	Geothermal, solar, etc.	Biofuels and waste	Electricity	Heat	Total**
Residential	4	0	1037	331	0	0	265	715	1441	52	3845
Commercial and public services	0	0	120	144	0	0	16	27	1531	0	1839
Agriculture /forestry	1	0	36	1	0	0	3	29	195	0	264
Fishing	0	0	13	0	0	0	0	0	2	0	15
Non-specified	0	0	230	0	0	0	0	1	0	0	230
Non-energy use	0	0	421	485	0	0	0	0	0	0	906

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feedstocks, additives and other hydrocarbons. **Totals may not add up due to rounding. ***International marine and aviation bunkers are included in transport for world totals. Source: IEA

Energy Mix

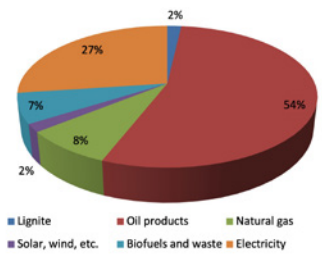
In general, the Greek energy sector is characterized by the existence of limited domestic resources, as Table 5,111 illustrates, resulting in a huge dependence on external energy resources.

Table 5.111 **Greek Energy Mix (Supply and Consumption) in ktoe, 2018**

Fuel type	Production	Imports	Exports
Lignite	4,275	234	0
Crude Oil	201	30,032	-215
Oil products	0	3,663	-20,130
Natural gas	13	4,145	0
Nuclear	0	0	0
Hydro	494	0	0
Geothermal, solar, etc.	1,154	0	0
Biofuels and Waste	1,075	142	-18
Electricity	0	735	-195
Heat	0	0	0
Total	7,211	38,952	-20,558

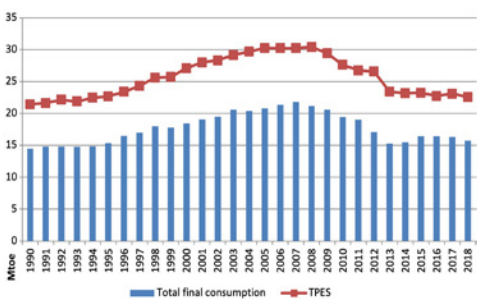
Source: IEA

Figure 5.97 **Total Final Consumption in Greece, per Primary Energy Source (2018) (Total=15,684 ktoe)**



Source: IEA

Figure 5.98 **Greece's TPES and TFC (1990-2018)**



Source: IEA

Degree of Energy Dependence

As depicted in the next Table, the energy dependence on imported sources in Greece was roughly 71% of the energy consumed in 2018 and an increase of 5.05% was achieved compared to 2009.

Table 5.112 **Energy Dependence in Greece, 2009-2018**

Import dependency (%)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Solid Fuels	2.0	5.1	2.9	2.3	3.2	2.9	2.9	4.4	4.8	5.1
Total petroleum products	96.8	98.7	93.9	101.4	94.7	99.9	105.5	99.7	98.1	97.9
Gas	99.7	99.9	100.0	100.3	100.0	99.3	99.9	99.2	100.5	100.7
Total	67.3	68.6	64.7	65.9	61.8	65.5	71.0	72.9	71.3	70.7

*Energy dependency shows the extent to which an economy relies upon imports in order to meet its energy needs. The indicator is calculated as net imports divided by the sum of gross inland energy consumption plus bunkers.
Source: Eurostat

The Energy Market

Greece's energy market covers activities in oil (upstream and mainly downstream), gas imports and distribution as well as electricity generation, transmission and distribution. The market also includes activities, covering solar thermal utilization and electricity generation for solar PV, wind and small hydro. There is limited activity in geothermal and biomass utilization. Furthermore, there is an increasingly input activity in energy efficiency applications for buildings.

OIL AND PETROLEUM PRODUCTS

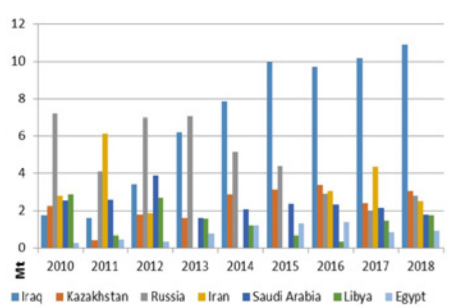
(a) Oil Production, Imports and Exports

The production of crude oil in Greece in 2018 was insignificant (0.21 million tons, Mt) as compared to domestic final consumption of oil products at approx. 8.8 Mt in the same year. Indeed, it was derived from three oil fields (Prinos, Prinos North and Epsilon) of which the production, though increased by 450% over the last eight years, remained small at 3,300 barrels per day in 2019, when Greece consumes approx. 7.3 million tons or 142,000 barrels a day (average daily consumption of crude oil in the country). The company Energean is the sole oil producer in Greece. The three active oil fields, Prinos and Prinos North and Epsilon, are located offshore the island of Thasos in the Northern Aegean.

Therefore, Greece depends on imports of large quantities of crude oil in order to cover its needs. Iraq was the biggest crude oil supplier to Greece in 2018 with 10.9 Mt, followed by Kazakhstan and Russia with 3.1 Mt and 2.8 Mt respectively (see Figure 5.99). Imports from Iraq only accounted for 46% of total crude oil imports in Greece in 2018, which amounted to approx. 23.7 Mt.

Imported crude oil is refined into oil products at four domestic refineries. Greece has increased considerably its refining capability in recent years, with exports of oil products at 20 million tons in 2018, according to IEA data[1]. Greece also imports oil products, with imports at 3.8 million tons in 2018.

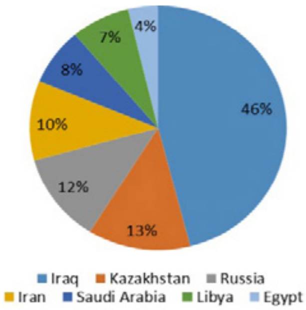
Figure 5.99 **Greece's Crude Oil Imports by Country, 2010-2018**



Source: Greece's Ministry of Energy

[1] https://www.iea.org/data-and-statistics?country=GREECE&fuel=Oil&indicator=Oil%20products%20imports%20vs.%20exports

Figure 5.100 **Greece's Crude Oil Imports by Country, 2018**

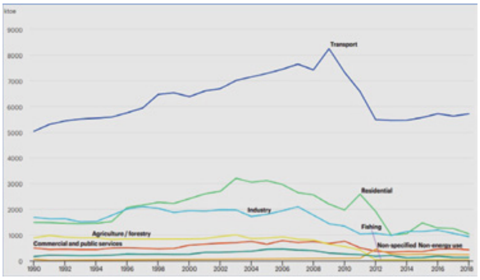


Source: Greece's Ministry of Energy

(b) Oil Consumption

Over the period 2005-2015, oil consumption in Greece recorded a sudden drop by one third due to the economic crisis of 2008 (see Figure 5.101) and the Greek financial crisis that ensued, especially after 2009. In recent years, however, oil consumption recovered, rising by 9% between 2013 and 2015, mainly in transport and to an extent in the residential sector.

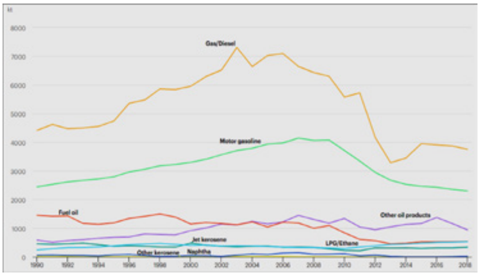
Figure 5.101 **Oil Consumption by Sector, 1990-2018**



Source: Greece's Ministry of Energy

The transport sector consumed 5.6 Mtoe of oil in 2017 or 50% of total oil consumption. Road transport accounts for 87% of total oil consumption in transport, followed by domestic shipping at 10% and smaller shares for domestic air and railway transport. The transport sector mainly consumes diesel and gasoline, which together account for 62% of total oil consumption in Greece (see Figure 5.102).

Figure 5.102 **Oil Consumption by Product, 1990-2018**



Source: Greece's Ministry of Energy

Approximately one third of the diesel is consumed in the residential sector for space heating. Heating oil represents one third of total residential energy consumption, the fourth highest share among IEA member-states. Residential oil consumption was considerably higher before the financial crisis (2009-2018). More specifically, it declined by 62% between 2011 and 2014, mainly due to a conjunction of high heating oil prices, reduced household income, and increased penetration of natural gas use because of a change in government policy (change of fuel in favour of biomass and natural gas). Consumption rose again in 2015.

Furthermore, Greece, in comparison to other countries, consumes a higher percentage of oil in power generation. Oil production units located on the islands accounted for 11% of total electricity generation in 2015, which was the highest among all IEA member-states. This is because many of the Greek islands are not yet connected to the mainland power grid but are supplied by autonomous production stations operating with oil-fired units (diesel and fuel oil).

(c) Upstream Sector – Domestic Exploration and Production

In 2018, oil production from the Prinos oil field, which is in operation since 1981, was minimal at 0.21 million tonnes, corresponding to 1.5 million barrels of oil.

In Greece, the most significant development in the hydrocarbon sector over the past year was the signing in early July 2019 of agreements for four large concession areas with four joint ventures of Greek and foreign companies for the areas south and southwest of Crete and the Ionian Sea. The four concession areas in Greek territory in 2019 are depicted in Table 5.113; the relevant agreements were ratified by Parliament on October 10, 2019.

1. For the offshore area **"Ionian"** in western Greece, an agreement was signed on April 9, 2019 between the Greek State and the Repsol-HELPE joint venture. Also signed on the same day was the agreement for "Block 10 Ionian Sea" (in the Gulf of Kyparissia) between the Greek State and HELPE.
2. For concession and exploration and exploitation rights of the offshore areas **"Southwest and West of Crete"**, the agreements were signed on June 27, 2019. Earlier, in the first days of July 2018, it was announced that the Total-ExxonMobil-HELPE joint venture had been formally declared as the successful bidder in the international tender held by the Ministry of Energy.

Table 5.113 **Hydrocarbon Concessions and Contracting Companies in Greece, 2019**

Date of publication in the Govt. Gazette (date when the agreement comes into effect)	Block	Location	Stage	Lessees, assignee, rates of participation
10/10/2019	Southwest of Crete	Offshore	Research	Total (40%, Assignee), ExxonMobil (40%), HELPE (20%)
10/10/2019	West of Crete	Offshore	Research	Total (40%, Assignee), ExxonMobil (40%), HELPE (20%)
10/10/2019	Ionian Sea	Offshore	Research	HELPE (50%, Assignee), Repsol (50%)
10/10/2019	Block 10	Offshore	Research	HELPE (100%)

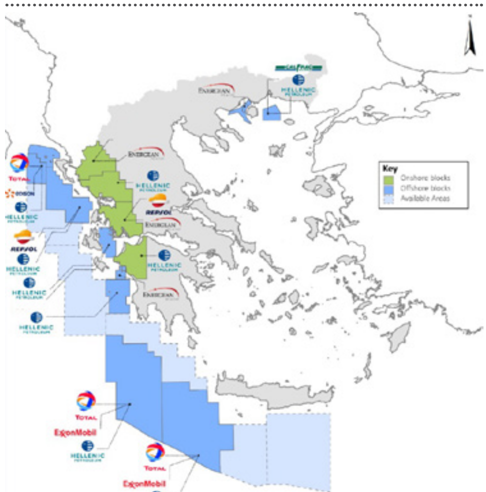
Source: HHRM

However, the required seismic surveys in the above offshore blocks southwest and west of Crete are expected to be delayed due to the spread of the coronavirus pandemic, while the dramatic fall in oil prices has resulted in negative market sentiment delaying further any real progress. The exact date will be set depending, inter alia, on the availability of special seismic survey ships and weather conditions. It is worth noting that the initial seismic surveys for the Crete area appear encouraging, especially regarding the "Talos" field, which has a geological structure similar to that of the well-known Zohr field off the coast of Egypt.

Another important development was the announcement of the acquisition last February by Energean of the 50% share held by the French company Total in offshore Block 2 in the Ionian Sea. Since Energean is also in the process of acquiring Edison E&P, which holds 25% of exploration and exploitation rights over Block 2. The deal has been completed a year ago, now Energean holds 75% and Hellenic Petroleum the remaining 25%.

Energean has said that exploration up to now in that area indicates that "Block 2" includes part of a wider potential target, extending by 60% in Greek territory and by 40% in Italian, in a maritime area where Edison is active.

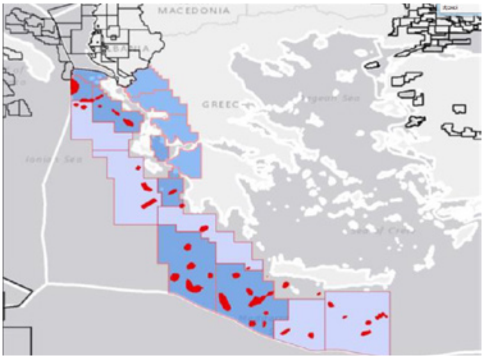
Map 5.24 **Concession Areas in Greece, December 2019**



Source: HHRM

According to HHRM, domestic hydrocarbon exploration activities are not only limited to the above areas that are already the concession areas, but also extend to offshore blocks that are available for concession. During the last months of 2019, the geological features of these blocks in the central Ionian Sea and south Crete were presented by HHRM to the international market and fora and have attracted the interest of international oil companies.

Map 5.25 **Hydrocarbon Fields-Targets in the Ionian Sea and Crete, 2019**



Source: HHRM

Regarding the area to the west and south-west of Crete, HHRM notes that the potential targets are located in rocks hidden under the seabed, while depths exceed by far 1,500 metres.

Average water depth in these areas exceeds 2,500 metres and in many cases it is around 3,500 metres. Technology for drilling at such depths is expected to be available over the next three years, and the companies will decide then whether or not to proceed with exploratory drilling. It is worth mentioning that areas that appear of interest do not necessarily "conceal" hydrocarbon quantities; this can only be confirmed with drilling operations. However, it is encouraging that in neighbouring countries, featuring similar geomorphology, hydrocarbons have been discovered and are already being exploited.

(d) Downstream and Midstream Sectors Infrastructure

Oil Pipelines

Greece has two oil pipelines, only one of which is operational. The 53 km Aircraft Fuel Supply Pipeline links HELPE's Aspropyrgos refinery to Athens International Airport at Spata. It is operated by the Athens Airport Fuel Pipeline Company, which also financed and constructed the pipeline. With a capacity of 2.6 mcm per annum, it is considered sufficient to accommodate the potential growth of air traffic well into the future.

The second, a 210 km crude oil pipeline, links HELPE's Thessaloniki refinery with its Okta refinery in North Macedonia. The pipeline has not been in operation since 2013. Plans to build a pipeline to link Greece with Bulgaria to offer an alternative supply route for Russian and Caspian oil have been discussed for over a decade without much progress. Most crude oil and products are moved by trucks and ships within Greece, while supplies to power plants are transported by train.

Oil Terminals

There are ten oil terminals in Greece, with a total loading capacity of 0.8 mcm per day and a total discharging capacity of 2.3 mcm per day. Seven of them are located in the Attica Area (including Athens) and three are in the Thessaloniki area. Six oil terminals (Aspropyrgos, Elefsina, Thessaloniki, Aghioi Theodori, Pachi, and Agia Triada) receive crude oil; four of these are located near the refineries. The country's total crude oil discharging capacity is around 1.6 mcm per day.

Oil Storage

Greece's combined storage capacity was around 10.2 mcm (equivalent to 64 million barrels) in 2018, and was used for industry operations and mandatory industry stocks. This shows that the country has sufficient storage capacity to meet the IEA 90-day obligation, which required Greece to have 3.5 mcm (22 million barrels) of oil storage capacity in 2018.

Oil Refineries

Imported crude oil is refined into oil products at four domestic refineries (see Table 5.114). The three refineries that belong to HELPE (Hellenic Petroleum S.A.) are located in Aspropyrgos, Elefsina and Thessaloniki and represent approx. 65% of the country's total refining capacity, with crude oil and oil product storage tanks having a total capacity of 6.65 million cubic metres. The refinery of Motor Oil at Agioi Theodoroi near Corinth produces the rest.

In 2019, the utilisation rate of HELPE's refineries was negatively affected by the completion of the current cycle of operation at the refineries of Aspropyrgos and Elefsina and the temporary suspension of operation for maintenance works at the Elefsina refinery, which were completed in the fourth quarter. Consequently, the production of HELPE's refining sector recorded a slight drop and amounted to 14.2 million tons in 2019. HELPE's sales were impacted commensurately and amounted to 15.2 million tons; exports stood at 7.9 million tons or 52% of total sales, and sales of aviation and shipping fuel were up 5% at 2.8 million tons. The production of the Motor Oil refinery also recorded a slight decline in 2019 compared to 2018 and amounted to 12.1 million tons, while sales stood at 14.4 million tons at approx. the same levels as in 2018. It is worth noting that Motor Oil's lower production and quantity of crude oil and raw materials processed in 2019 compared to 2018 was due to the scheduled periodic maintenance of the refinery's units. The Motor Oil refinery has also acquired the flexibility to process a broad range of crude oil types; thus, contributing to import diversification. Furthermore, the refinery can now easily switch between diesel and gasoline production and adapt to seasonal changes in Greece's demand. The upgrade and modernisation works have placed the refineries among the most profitable in Europe, and their specifications are modern and environment-friendly.

Table 5.114 **Refineries in Greece**

	Hellenic Petroleum (HELPE) S.A.			MOTOR OIL
Ownership	Paneuropean Oil and Industrial Holdings S.A: 42.6% Hellenic Republic Asset Development Fund: 35.5% Institutional investors: 15.3% Private investors: 6.6% Free float: 23.5%			Petroventure Holdings Limited: 40,0%; Doson Investments Company: 8,1%; Free float: 51,9%
Location	Aspropyrgos	Thessaloniki	Elefsina	Agioi Theodoroi (Corinth)
Type of Refining	Highly complex: catalytic, thermal, and hydro-cracking; MTBE* production; vacuum distillation	Hydroskimming; vacuum distillation; isomerisation; reforming	Topping: atmospheric distillation only; no vacuum distillation, reforming or desulphurisation	Complex: catalytic and thermal cracking; isomerisation; MTBE production; vacuum distillation; mild hydrocracking; hydrotreating; reforming; lube production; alkylation; dimerisation
Nelson Complexity Index	9.7	5.8	12	11.54
Capacity (Mt/year)	7.5	4.5	5.3	10
Capacity (kb/d)	148	90	106	185
Year established	1958	1966	1972	1972

Sources: IENE, HELPE and Motor Oil

Based on data by the Hellenic Petroleum Marketing Companies Association (SEEPE), domestic market's fuel sales were up 0.45%, from 6,655,720 tons in 2014 to 6,685,490 tons in 2018. More specifically, the domestic market's sales of gasoline declined by 8.98% (2014: 2,516,270 tons - 2018: 2,290,214 tons), sales of heating oil grew by 10.62% (2014: 2,363,892 tons - 2018: 2,614,881 tons), while fuel oil sales declined by 13.66% (2014: 208,029 tons - 2018: 179,616 tons). LPG sales rose by 17.28% (2014: 437,955 tons - 2018: 513,623 tons) due to increased use of autogas, kerosene sales dropped by 16.57% (2014: 3,145 tons - 2018: 2,624 tons), and asphalt sales dropped by 27.44% (2014: 158,683 tons - 2018: 115,141 tons). The reduction in the consumption of petroleum products in 2018 compared to 2017 was mainly due to the reduced consumption of heating oil and unleaded gasoline.

Map 5.26 **Oil Infrastructure in Greece**

Source: IEA

(e) Security of Supply

Greece meets its stockholding obligation to the IEA and the EU by placing a stockholding obligation on industry. According to Law 3054/2002 (on organisation of the oil market) and Law 4123/2013 (on maintaining minimum stocks of crude oil and petroleum products), all oil importers and large end users (such as power plants) are required to hold oil stocks equivalent to 90 days of their net imports made during the previous year. Industries are required to hold compulsory stocks in facilities that have been certified as emergency stock storage tanks. Emergency stocks can be held in the same facility as industry stocks; in practice, compulsory stocks are commingled with operational/commercial stocks.

All the storage facilities owned by refineries are certified tanks for emergency stocks. HELPE operates around 70% of the total Greek storage facilities, and it is the country's largest refining company. Part of the storage facilities is used for maintaining stocks for third parties in the context of European Directive 2009/119/EC. Foreign companies with term/spot commercial storage agreements and clients who require oil storage capacity to obtain retailing licenses can make use of the available storage capacity.

(f) Planned new projects

Currently, there is no planned new project in the Greek oil sector. In the map shown earlier regarding oil infrastructure in Greece, the green-dotted line is referred to the Burgas – Alexandroupoli oil pipeline that was expected to be used for transporting Caspian and Russian oil from the Bulgarian Black Sea port of Burgas to the Greek port of Alexandroupolis. The only planned 300-km pipeline construction was suspended in December 2011 by the Bulgarian government due to environmental and supply concerns.

NATURAL GAS

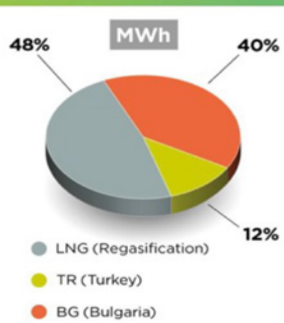
The Greek gas market appears to have recovered in 2019, after the extended period of financial crisis. In parallel, implementation of the actions outlined in the Gas Market Roadmap 2017-2022[2] continued; especially, those that aim at a transition to a fully deregulated market (e.g. reforms in the retail and wholesale markets, and corporate restructuring of supply companies).

(a) Natural Gas Consumption, Imports and Exports

Based on data provided by DESFA[3], total consumption of natural gas in Greece in 2019 amounted to 57.4 TWh or 4.9 billion cubic metres, up 10% compared to the respective figure for 2018 and up 79% compared to 2014. Therefore, gas consumption in 2019 was the highest since it was first introduced in the country. It is worth mentioning that in 2019 Greece exported to Bulgaria gas quantities amounting to 7.7 TWh.

Figure 5.103 **Natural Gas Consumption, Imports and Exports in Greece, 2019**

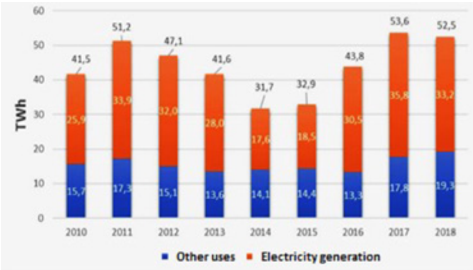
	MWh	Nm³
Natural Gas Consumption	57.407.326	4.943.457.468
Natural Gas Imports		
LNG (Regasification)	31.008.180	2.635.382.903
TR (Turkey)	8.108.942	695.244.866
BG (Bulgaria)	25.667.513	2.261.454.873
Natural Gas Exports		
BG (Bulgaria)	7.701.872	678.579.018



Source: DESFA

[2] Govt. Gazette B' 59/18.01.2018
[3] https://www.desfa.gr/userfiles/pdflist/DERY/TT/Leit_Stoix_ESFA_2019.pdf

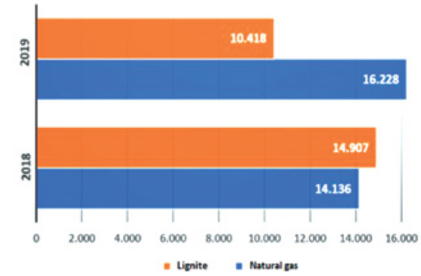
Figure 5.104 **Evolution of Gas Consumption in Greece, 2010-2018**



Source: RAE

The highest percentage of natural gas in 2019, as in all past years, was consumed in power generation by PPC's thermal units and private electricity producers. Indeed, the role of natural gas in power generation rose considerably in 2019 as compared to 2018. As shown in Figure 5.104, the production of units using natural gas as fuel increased by 15% in 2019 compared to 2018; on the contrary, the electricity generation from lignite was reduced by 30% compared to 2018.

Figure 5.105 **Annual Production (GWh) of Thermal Stations in Greece, 2018-2019**



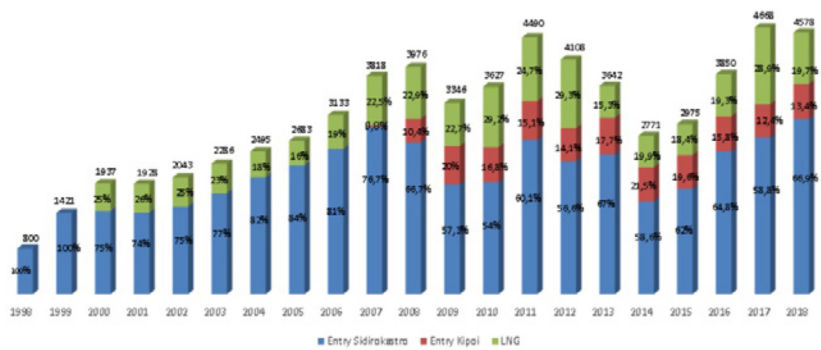
Source: IPTO

The penetration of natural gas in Greece remained at very low levels in 2018 (8%), compared to the average in other European countries, where it reaches 55% and thus, electricity generation is still the main factor in Greece's gas demand.

(b) Sources of Natural Gas Supply in 2019

2019 was a reference year for the evolution of the market share between piped gas and imported LNG into Greece. Figure 5.106 depicts the contribution share of piped gas and LNG over the period 1998-2018.

Figure 5.106 **Evolution of Gas Imports into Greece, 1998-2018**

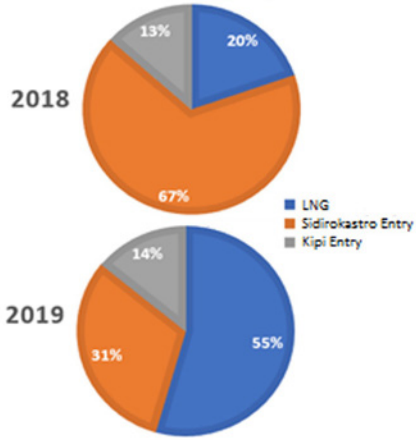


Source: DESFA

These shares changed significantly in 2019 compared to 2018. More specifically, LNG accounted for 55% in 2019 against 45% for piped gas, when the maximum share of LNG had been 29% in 2010 and 2012. In 2018, LNG accounted for 20%. It is the first time that LNG exceeded in quantity the gas supplied via pipelines.

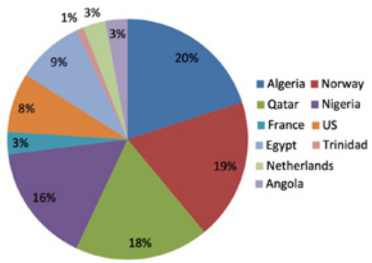
[4] Sedigás informe "año gasista 2016 y Perspectivas 2017"; BP Statistical Review of world energy 2017.

Figure 5.107 **Change in the Share of Gas Supply Sources in Greece, 2018-2019**



Source: DESFA

Figure 5.108 **LNG Imports into Greece by Country of Origin, 2019**



Source: DESFA

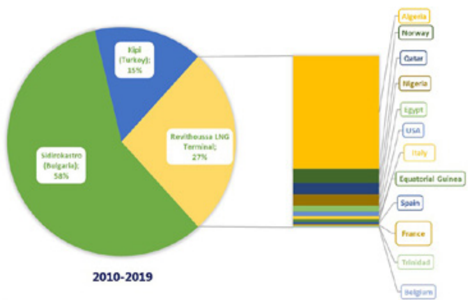
(c) Natural Gas Infrastructure

The natural gas transmission system has three entry points: two at the north and north-eastern borders (Sidirokastro and Kipi), connecting Greece with the Bulgarian and Turkish gas networks, and one in southern Greece (Agia Triada), linked to the LNG terminal. The biggest natural gas infrastructure of Greece is the LNG terminal on Revithoussa Island. It plays a key role in the operation of the natural gas transmission system, especially during security of supply crises. Currently, there is no underground gas storage in Greece. The country's only storage facility is located at the Revithoussa LNG terminal. However, the government has plans for underground storage in the exhausted Kavala offshore gas field.

Revithoussa LNG Terminal

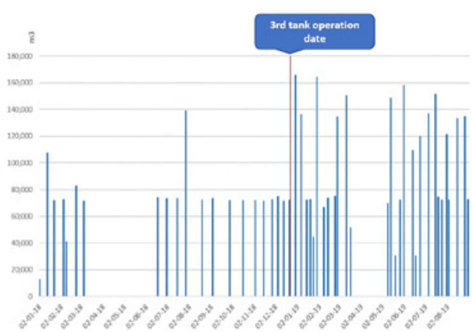
In January 2019, the commercial operation of the third storage tank of the terminal commenced. In parallel, in the context of the second upgrade of the terminal, the capacity for LNG gasification increased, and there is now the possibility of mooring larger LNG tankers, up to Q-MAX size (in practice, the largest LNG tankers in the global market can now be accommodated). Based on the operational data of the LNG terminal for 2019, it is clear that the target of handling greater LNG quantities has been achieved; thus, improving the liquidity of the market and strengthening the country's security of gas supply. According to DESFA's data[5], there was an increase both in sources of gas supply and in the number of unloadings after the upgrade of the terminal (see Figure 5.109).

Figure 5.109 **Countries of Origin of LNG Imports at the Revithoussa Terminal, 2010-2019**



Source: DESFA

Figure 5.110 **Number of LNG Unloadings Before and After the Upgrade of the Third Tank**

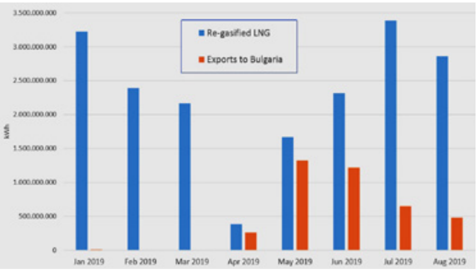


Source: DESFA

[5] Avlonitis, G. (2019), "Wholesale market and infrastructure", RAE Day Conference (84th TIF), http://www.rae.gr/site/file/categories_new/about_rae/factsheets/2019/gen/16092019?p=file&i=1

Lastly, the upgrade of the LNG terminal also contributed (increase from 1 mcm/d to 5.5 mcm/d after the upgrade[6]) to realising gas exports to Bulgaria via the Sidirokastro Reverse Flow Exit Point, as shown in Figure 5.111.

Figure 5.111 **The Role of the Upgraded LNG Terminal in Cross-Border Trade**

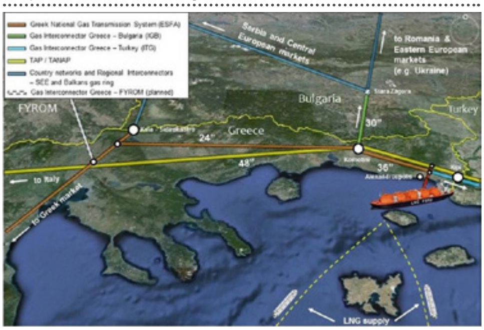


Source: DESFA

Alexandroupolis FSRU

The project will consist of one Floating Storage Regasification Unit (FSRU), which will be permanently moored at a fixed point at a distance of 17.6 km south-west of Alexandroupolis harbour and 10 km from the coast at Makri.

Map 5.27 **Alexandroupolis FSRU**



Source: Gastrade

Gastrade, a company of the Copelouzos Group, is developing the project in Alexandroupolis; the budget is €380 million and the annual capacity is 5.5 bcm. The project constitutes a departure in terms of national energy policy, but is also of high significance for Europe. It is part of the EU's policy for Central and South-eastern Europe Energy Connectivity (CESEC) with the European Natural Gas System via the development of a Vertical Corridor and has been included in the updated list of Projects of Common Interest of 30 October 2019[7].

The first non-binding phase of the Market Test was successfully completed on December 31, 2018, in which 20 companies expressed their interest for 12.2 bcm per year. On December 23, 2019, DEPA's Board of Directors approved the participation of the company in Gastrade's share capital with a share of 20%. On January 8, 2020, the participation of Bulgartransgaz EAD in Gastrade's share capital was also approved with a share of 20%, and the related agreement was signed in late August. Thus, the shareholder composition now stands as follows: Copelouzos Group 40%, GasLog 20%, DEPA 20% and Bulgartransgaz 20%.

On January 10, 2020, the second phase of the Market Test went ahead, whereby interested parties were invited to submit binding offers by March 24, 2020, after a third extension was given. By that deadline, binding offers for total quantities of 2.6 bcm per year had been submitted, with a timetable of 5 to 15 years. Binding offers were submitted by DEPA and PPC on the Greek side, the Bulgarian company Bulgartransgaz, and two private trading companies from Romania and Serbia.

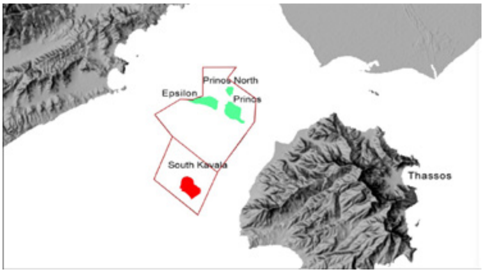
In early March 2020, three groups submitted offers for the construction of the pipeline and other works that will connect the Alexandroupolis FSRU with the National Natural Gas Transmission System. More specifically, binding offers were submitted by the joint venture of the Italian firm Saipem with the Greek construction company TERNA and the Dutch companies BOSKALIS and VAN OORD. According to the expected project's timetable, the Final Investment Decision (FID) is expected in the fourth quarter of 2020. The construction of the FSRU will last two years and the commencement of commercial operation is scheduled for early 2023.

[6] DESFA (2017), "10-year Forecast for Technical Capacity of Natural Gas Transmission System Entry Points", https://www.desfa.gr/userfiles/pdflist/anathewrimenes_texn_dynamikotites_07-2017-gr-v2.pdf
[7] ANNEX to COMMISSION DELEGATED REGULATION (EU) amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the Union list of projects of common interest SWD(2019) 395 final.

South Kavala Underground Gas Storage (UGS)

This project, having a budget of €300 million - €400 million, aims at exploiting the depleted offshore gas field of South Kavala (used by the company Energean – remaining gas reserves assessed at 0.073 bcm) as an underground gas storage facility. It is located in the Gulf of Kavala, 11 km south of the Prinos oil field, at a depth of 1,700 metres.

Map 5.28 **The Red-coloured Area is the Depleted Natural Gas Field in South Kavala**



Source: Energean

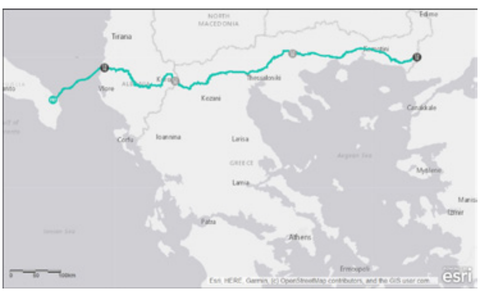
The South Kavala UGS is an energy infrastructure project that will enhance the security of gas supply at national and European level for the benefit of the end consumer. It offers long-term capability for the storage of natural gas, in contrast to the Revithoussa LNG terminal, which is suitable only for short-term storage. It should be noted that Greece is the only EU country that has no permanent underground gas storage facility even though 40% of the country's electricity generation is now based on natural gas. European countries store at minimum 20% of their annual gas consumption in underground gas storage facilities. According to the preliminary plans of the project, the capacity of the UGS is assessed at approx. 1 bcm. Annual volume throughput is assessed at 360 million Nm3 or 720 million Nm3, for one or two cycles per year, respectively. It is worth mentioning that the project has been included in the list of Projects of Common Interest (PCI) that was adopted on October 30, 2019 (Cluster increase storage capacity in South-Eastern Europe) by the European Commission and the member states at the meeting of Regional Teams for the PCIs.

On March 10, 2020, a Joint Ministerial Decision[8] was issued for commencing the procedure of exploiting the field. More specifically, the Hellenic Republic Asset Development Fund (TAIPED) will conduct an international tender for the concession of rights for the construction, maintenance, operation and exploitation of the field as a UGS for a period of up to 50 years. On June 29, 2020, TAIPED announced[9] the commencement of an international tender procedure for the concession of rights for the use, development and exploitation of the underground natural field at the location of the almost depleted gas field "South Kavala", with the aim of converting it into a gas storage facility. On August 11, 2020, TAIPED announced[10] an extension to September 30, 2020 of the deadline for expressing interest for the concession agreement for the use, development and exploitation of the underground natural field at the location of the natural gas field "South Kavala". Two schemes have expressed their interest about the project, Energean and DESFA- GEK Terna.

Trans Adriatic Pipeline (TAP)

The Trans Adriatic Pipeline (TAP) project involves the construction of a gas pipeline that will transport gas from the area of the Caspian Sea to Europe. TAP is now connected to the Trans Anatolian Pipeline (TANAP) at the Greek-Turkish border and then continues through northern Greece, Albania and the Adriatic Sea before terminating at the coast of southern Italy, where it is connected to the Italian natural gas system.

Map 5.29 **TAP Route**



Source: TAP AG

[8] https://diavgeia.gov.gr/doc/%CE%A9%CE%99%CE%93%CE%A74653%CE%A08-6%CE%95%CE%A5?inline=true
[9] https://www.hradf.com/storage/files/uploads/yafa-e-narkshdiagwnismoy-29062020.pdf
[10] https://www.hradf.com/storage/files/uploads/yafa-e-narkshdiagwnismoy-29062020.pdf

The TAP pipeline will be connected with the Greek Natural Gas System and the IGB pipeline. It will also provide new Exit Points for supplying gas distribution networks in Western Macedonia, and will have reverse flow capability for transmitting gas at competitive prices via the Italian system. On July 1, 2019, the project operator conducted a Market Test, in accordance with the guidelines approved by the Regulatory Authorities of Greece, Italy and Albania. The Non-Binding stage was completed on October 21, 2019 with the publication of the Demand Assessment Phase Report.

On March 30, 2019, the installation of the first pipelines of the project's offshore section was completed successfully, with a length of 105 km, connecting the coasts of Albania and Italy. Construction work on that section started in October 2018. On November 25, 2019, the introduction of natural gas in a 2-km section of the pipeline (between Evros and the Kipoi Compression Terminal)[11] commenced. This is the initial stage of the commissioning process, and aims at ensuring that the project is fully safe and ready for operation. According to data[12] provided by the project operator, the project was 95% completed by late April 2020.

On January 20, 2020, the three operators involved in natural gas transmission systems (TAP, SRG and DESFA) invited those interested in participating in a public consultation concerning a proposal for increased capacity for the TAP pipeline up to February 21, 2020. In early June 2020, the three operators announced that the binding phase of the market test for increased capacity is expected to be realised in July 2021, rather than in January of that year as initially scheduled, so that more time is given for the energy markets to recover, following the coronavirus pandemic.

Interconnector Greece - Bulgaria (IGB)

The project of the Greek - Bulgarian Interconnector (IGB) consists of a pipeline with a length of 182 km that begins in Komotini and ends in Stara Zagora, effectively connecting the gas networks of Greece and Bulgaria, while it will have reverse flow capability. The project has been included in the latest list of PCIs of October 30, 2019. In addition, the Greek - Bulgarian interconnector is included in the list of priority projects of the Central and South-Eastern Europe Gas Connectivity (CESEC) initiative. It is anticipated that gas transmission to the markets of Bulgaria and South-Eastern Europe will be increased via the IGB.

Map 5.30 **IGB Route**

Source: ENTSOG

On April 3, 2019, the EU approved financing of €39 million for the construction of the project. On July 18, 2019, RAE granted to the company ICGB AD (50% Bulgarian state company BEH – 50% YAFA Poseidon S.A.) pursuant to its decision No. 671/2019, a licence for an Independent Natural Gas System (ASFA).
The ASFA concerns the Greek section of the Greek - Bulgarian interconnector (IGB). According to the above decision, the IGB will be connected with the National Natural Gas System (ESFA), the TAP natural gas transmission system and Bulgaria's natural gas transmission system, and will strengthen the position of Greece as regional energy hub, contributing to the increase of competition in Greece's natural gas market and creating benefits for both domestic and Bulgarian consumers.

[11] TAP (2019), "TAP Introduces First Natural Gas into the Greek Section of the Pipeline as part of its Testing Phase", https://www.tap-ag.com/news-and-events/2019/11/26/tap-introduces-first-natural-gas-into-the-greek-section-of-the-pipeline-as-part-of-its-testing-phase
[12] TAP (2020), "Project progress", https://www.tap-ag.com/pipeline-construction/project-progress

In early October 2019, the Regulatory Authorities of Greece and Bulgaria jointly approved the project's Operation Code and Pricing Regulations.

On October 10, 2019, Bulgaria's Energy Minister Mrs. Temenuzhka Petkova and the Minister of the Environment and Energy of the Hellenic Republic Mr. Kostis Hatzidakis signed an Intergovernmental Agreement setting the terms of construction and operation of the pipeline by the company ICGB AD.

Construction work on the pipeline started on October 28, 2019 and will last 18 months. The pipeline has been designed in order to operate in two phases. In the first phase, expected to start commercial operation on July 1, 2021, the capacity of the pipeline will be 3.0 bcm per year, of which 2.7 bcm will be offered for long-term products and 0.3 bcm for short-term products. In the second phase, subject to additional commercial interest, the capacity of the pipeline can be increased up to a total of 5 bcm per year with the addition of a compressor, of which 4.5 bcm will be offered for long-term products and 0.5 bcm for short-term products.

Poseidon Turkey - Greece - Italy Pipeline (ITGI)

The Poseidon Greece - Italy Interconnector consists of two sections: (a) the onshore section, with a length of approx. 760 km, which begins at the Greek - Turkish border at Kipoi and passes through the Regions of eastern Macedonia and Thrace, central Macedonia, Western Macedonia, Thessaly and Epirus before terminating at the coast of Thesprotia; and (b) the offshore section of the project, with a length of approx. 210 km, which connects the coast of Thesprotia with Otranto in Italy.

The offshore section of the project (Greece - Italy) has been included in the latest list of PCIs, of October 30, 2019. In the Development Study 2020-2029 prepared by DESFA, the final investment decision of this project will be reached after conducting a market test. According to the decision of March 26, 2020 13, the installation and route of the onshore section of the Greek part of the pipeline, with a length of 8.2 km, from the Metering and Compression facilities in Thesprotia to the landing point of the sea route to Epirus were set. The main concern about this project is whether and to what extent is directly competitive with TAP or whether it constitutes an additional route for potential Russian gas exports to Europe.

Map 5.31 **IGI Route**

Source: DEPA

Interconnector Greece - North Macedonia (IGNM)

The construction of this pipeline, with a budget of €47.8 million and an annual capacity of 3 bcm, aims at interconnecting the natural gas systems of Greece and North Macedonia and achieving a diversification in North Macedonia's gas supply sources, which until recently were entirely dependent on the Trans Balkan Pipeline and since January 2020 on Turkish Stream, via Bulgaria.

The access to ESFA and especially to the Revithoussa terminal and to gas via TAP will enhance competition; thus, potentially leading to lower gas supply prices in the neighbouring country. At the same time, this project promotes the development of a regional gas market and the entry of more users, contributing to the growth of the Greek gas hub, which in turn will result in better gas

[13] https://diavgeia.gov.gr/doc/%CE%A8%CE%9B%CE%A5%CE%A84653%CE%A08-%CE%983%CE%A7?inline=true

prices in the Greek market too. It will also contribute to an increase in the use of Greece's infrastructure, such as the Revithoussa LNG terminal, with the aim of lowering system user charges in the long term. The project within Greek territory consists of the construction of a 54.3 km pipeline beginning at Nea Mesimvria and extending to the border with North Macedonia.

Map 5.32 **IGNM Route**

Source: ENTSOG

The final investment decision is expected in December 2020. The project will be implemented after the signing of a cooperation agreement with MER (state-owned company for the exploitation of North Macedonia's energy resources), which will include the stages that must be followed by both sides for the implementation of the interconnection as well as the details of each side's obligations and responsibilities. The project is at the stage of completion of basic planning, while the environmental terms have already been approved.On February 6, 2020, Greece's Energy Ministry approved the environmental terms for the construction and operation of the project "High Pressure Gas Pipeline Nea Mesimvria - Eidomeni". In this decision, DESFA was named as the entity undertaking the proposed project. According to the approved ESFA Development Plan 2017-2026, the above decision covers one out of three terms linked to approving inclusion of the project in the Development Plan.

The other two concern the commitment of gas transport by users (requires the conduct of a market test by DESFA) and the decision about financing the project.

Ionian - Adriatic Pipeline (IAP)

The Ionian Adriatic Pipeline (IAP) is a proposed pipeline to supply gas in SE Europe. It begins in Albania and passes through Montenegro, Bosnia and Herzegovina and Croatia. In Albania, it will be connected to the TAP pipeline.

Map 5.33 **IAP Route**

Source: TAP AG

The project is currently at the stage of preliminary planning[14] (Croatia - Montenegro - Albania), while the construction licence procedure is in progress in Croatia and Albania.

Turkish Stream Pipeline

The Turkish Stream pipeline is a gas pipeline connecting Russia with Turkey across the Black Sea. On January 18, 2020, the opening ceremony was held, marking the first deliveries of natural gas to Turkey via the new Turkish Stream pipeline. On January 27, 2020[15], 1 bcm of natural gas was delivered via the pipeline.

Map 5.34 **Turkish Stream Route**

Source: Gazprom

[14] Energy Community (2020), "Ionian Adriatic Pipeline", https://energy-community.org/regionalinitiatives/infrastructure/PLIMA/Gas16.html

[15] Gazprom (2020), "First billion cubic meters of gas supplied via TurkStream", https://www.gazprom.com/press/news/2020/january/article498525/

In addition, according to an announcement by Bulgartransgaz, Russian gas for Bulgaria, Greece and North Macedonia is now delivered via the new entry point (on the Bulgaria - Turkey border). In practice, this means that as of early January 2020 Gazprom, by delivering gas via the Turkish Stream pipeline, replaced the route that passed through Ukraine and Romania via the Trans Balkan Pipeline. At the same time, new conditions are now in place for access to the LNG terminal at Revithoussa and to the Alexandroupolis FSRU.

The East Med Pipeline

This project was conceived by DEPA-Edison in 2011 and has been promoted by the above companies. The East Med pipeline is now included in the latest PCI list of October 30, 2019. On January 2, 2020, an Intergovernmental Agreement between Greece - Cyprus - Israel was signed in Athens for the implementation of the aforementioned project. Italy, which was absent in the ceremony, through the Italian Minister for Economic Development, Mr. Patuanelli, sent a letter to the Greek Minister for Environment and Energy, according to which Italy supports the project in the context of the European PCIs

Map 5.35 **East Med Pipeline Route**

Source: IGI Poseidon

On January 2, 2020, Energean and DEPA signed a Letter of Intent for the sale and purchase of 2 bcm of natural gas per year (corresponding to 20% of the pipeline's initial capacity) from Energean's fields (Karish and Tanin, via the FPSO "Energean Power") in Israel's Exclusive Economic Zone.

Further details, including terms, points of sale, the composition of the natural gas, the charterer, etc., will be agreed and included in the Gas Sales Purchase Agreement [16](GSPA).

On March 3, 2020, a Joint Ministerial Decision was issued approving the commencement of the licencing procedure for the East Med pipeline and especially for the Greek onshore section of the pipeline. The licencing procedure is expected to be completed by the fourth quarter of 2021, so that the implementation of the East Med pipeline can begin then, while it is expected to be completed in 2024. On April 29, 2020, YAFA Poseidon issued a call for the preliminary contruction activities for the East Med pipeline, with a total cost of €2.4 billion before tax and €2.97 billion after tax. More specifically, the activities concern the detailed engineering design, procurement, construction, transport, installation and pre-commissioning (EPCI) of the pipeline's offshore sections. This call for tenders concerns the first stage of the East Med pipeline, which is planned to transport 10 bcm/year plus 1 bcm for Cyprus, will end on June 20, and will be completed with the selection of two contractors.

The design and development of the first stage takes into account all research and development activities, including the related pre-investment, on the basis of a possible increase of the pipeline's capacity to 20 bcm/year at a later stage. The draft law for the Intergovernmental Agreement on the East Med pipeline was submitted to Parliament on May 4, 2020, after the licencing process for the project had commenced in Greece and a call for tenders had been issued for the main parts of the final feasibility study prepared by the entity undertaking the project, YAFA Poseidon. The Intergovernmental Agreement for the construction of the pipeline was ratified by the Greek Parliament on May 14, 2020.

The next steps of the project involve the completion of the feasibility study, amounting to approx. €70 million, and the taking of

[16] Energean (2020), "Energean and DEPA agreement paves the way for commercial operation of East Med pipeline", Joint Press Release, https://www.energean.com/media/3629/20100202-energean-depa-loi.pdf
[17] Satras, N. (2019), "DIORYGA GAS FSRU Project - part of European Natural Gas Grid", RAE Day Conference (84th TIF), http://www.rae.gr/site/file/categories_new/about_rae/factsheets/2019/gen/16092019?p=file&i=4

the final investment decision (FID). Taking also into account the data in the studies mentioned above, the greatest obstacles for the implementation of the project remain the following:

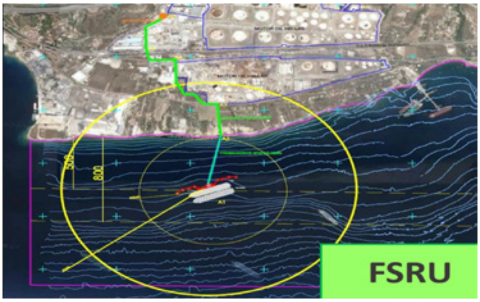
- ensuring sufficient quantities of natural gas for exports
- achieving competitive prices
- concluding a series of sale agreements with European customers

In addition, the technical challenges of the project will have to be met, especially the great depths at which certain subsea sections of the pipeline are planned. Given the current and future demand for natural gas in Europe, the potential contribution of the East Med pipeline in covering gas supply requirements will not exceed 3%, at best.

Dioryga Gas FSRU

This project (proposed and promoted by the Motor Oil Hellas group [17]) consists of a Floating Storage Regasification Unit to be anchored at a distance of 1.5 km south-west of Motor Oil's refinery in Agioi Theodoroi near Corinth. The project, which obtained an ASFA licence from RAE in early March 2019, will be connected to ESFA via an offshore and onshore pipeline. The planned storage capacity of the unit is 135,000 to 170,000 m3, with maximum regasification capacity of 470,000 ncm/h or an annual capacity of 2.6 bcm. The project will strengthen security of gas supply at national and European level, will constitute a new ESFA entry point, and, upon the required interconnections of ESFA with neighbouring gas systems, will obtain access to the countries of SE Europe.

Map 5.36 **Dioryga Gas FSRU**



Source: Motor Oil Hellas

It will also create benefits for the end consumer, since it will provide additional liquidity to the LNG market (lower procurement prices) and contribute to the decongestion of the LNG terminal at Revithoussa, of which the first indications emerged in the last quarter of 2019 and upon drafting the Final Annual LNG Unloading Plan for 2020 by DESFA . Lastly, the project may operate auxiliarily:

- with the LNG terminal at Revithoussa (proximity - double unloadings);
- with the 2020-2024 5-year Development Plan for the natural gas distribution network of DEDA (Public Gas Distribution Network), which provides LNG supply to the cities of Patras, Agrinio and Pyrgos;
- with activities in the emerging Marine LNG & Small-Scale LNG market.

ELECTRICITY

In Greece, the electricity market operated until recently on the basis of a pool structure, meaning that the total available power formed a "pool" from which participants in the distribution network drew the electricity they supply to their customers - consumers.In recent years, there has been an ongoing effort to exploit RES potential, with the aim of meeting the country's commitment for higher RES penetration into the Greek energy system, but also for exploiting domestic resources towards safeguarding energy supply. Emphasis is given to high commercial maturity technologies that exploit domestic potential (e.g. wind farms, solar PV parks, biomass, small hydro), which have attracted high investor interest. It is worth noting that gas and RES units have started replacing a large segment of lignite production, leading to a considerable increase in total installed capacity for power generation in the last decade thanks to the RES.

(a) Electricity Supply and Demand

Historically, lignite has played a significant role in Greece's power generation and covered almost 20% of total electricity demand in the interconnected – except of the islands - system

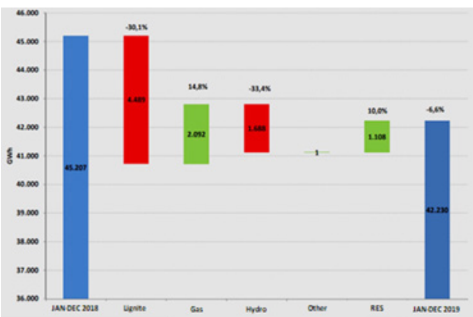
[18] Liaggou, Ch. (2019), "Οξύνεται ο ανταγωνισμός εγχώριων ομίλων στην αγορά φυσικού αερίου", https://www.kathimerini.gr/1052415/article/oikonomia/epixeirhseis/o3ynetai-o-antagwnismos-egxwriwn-omilwn-sthn-agora-fysikoy-aerioy

in 2019 and much higher share (more than 60%) in previous years. However, its dominance has been reduced in the last decade due to the fall in electricity consumption and the increased penetration of RES for power generation - mainly wind and solar - and natural gas. RES covered almost one third of the total domestic electricity demand over the three-year period 2017-2019.

Power Generation

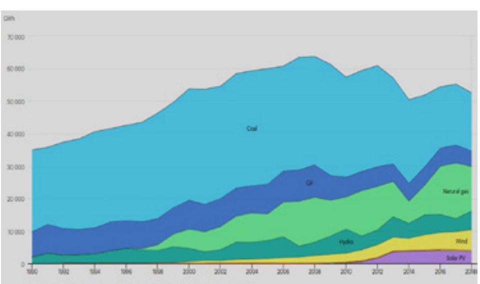
In 2019, Greece produced 42.2 TWh of electricity in the interconnected system, down 6.6% from levels in 2018. Natural gas was the largest source of energy in domestic power generation, accounting for 16.2 TWh in 2019, followed by RES, which increased their share from 11.1 TWh in 2018 to 12.2 TWh in 2019. The contribution of lignite in power generation has declined considerably over the last two years, from 14.9 TWh in 2018 to 10.4 TWh in 2019.

Figure 5.112 **Change in Power Generation (GWh) in the Greek Interconnected System, 2018-2019**



Source: IPTO[19]

Figure 5.113 **Power Generation by Type of Fuel, 1990-2018**

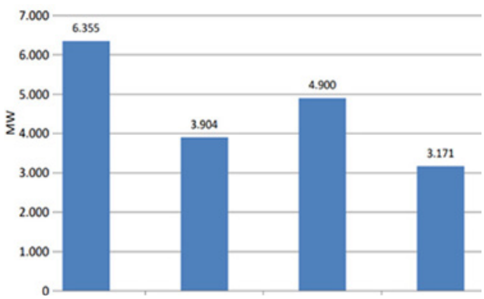


Source: IEA (2020)

Installed Capacity

In 2019, the total installed capacity of power generation units in the Greek interconnected system amounted to 18.3 GW, up 5.2% from levels in 2018 (17.4 GW). RES were the only power generation source that increased its share in domestic installed capacity in the interconnected system in 2019 as compared to 2018, with new installed capacity of 886 MW and total installed capacity at 6.3 GW. In 2019, the total installed capacity of lignite, hydro and gas units remained at the same levels as in 2018, as shown in Figure 5.114.

Figure 5.114 **Total Installed Capacity of Units by Type of Fuel in the Greek Interconnected System, 2019**



Source: Hellenic Energy Exchange

Electricity Imports and Exports

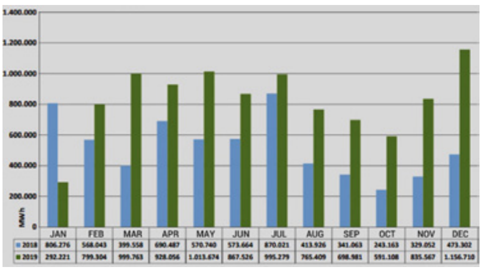
Greece is well connected to neighbouring countries and apart from the domestic electricity production is increasingly becoming active in power tading activities. However, the interconnection index[20] of the country's power grid is at 9%, i.e. at levels lower than in other power systems in SE Europe as the interconnection indices in Bulgaria and Rumania are at 12% and 11% respectively. Electricity imports increased due to new interconnections, though they vary considerably from year to year.

More specifically, electricity imports into Greece amounted to 9.6 TWh in 2019, mainly from Bulgaria, Italy and North Macedonia. Electricity exports amounted to 2.9 TWh in the same year, mainly routed to Italy, Albania and North Macedonia. Greece has been a net importer of electricity for many years, with total net imports in 2019 at approx. 6.7 TWh,

[19] http://www.admie.gr/fileadmin/groups/EDRETH/Monthly_Energy_Reports/Energy_Report_201912_v1.pdf
[20] Defined as the ratio of the import capacity of existing interconnections to the installed power generation capacity of the system each time.

covering approx. 13% of the country's needs, based on IPTO's data. It is worth noting that a second electricity interconnection between Bulgaria and Greece is under development and is expected to become operational by 2023. This project is of great importance for the market coupling of both countries, and is expected to increase considerably the interconnectivity of Greece and bring the country closer to the minimum European target of 15% by 2030.

Figure 5.115 **Electricity Balance (MWh) at the Interconnections of Greece, 2018-2019**



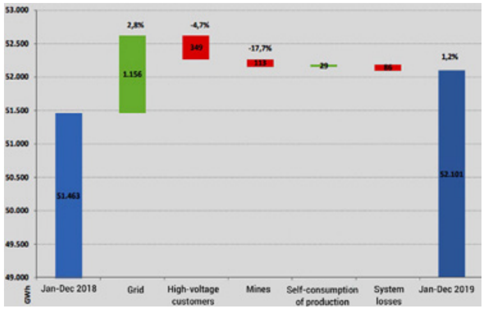
Note: The electricity balance at the interconnections is calculated as the difference ("Actual Import Flows" - "Actual Export Flows") for all interconnections.
Source: IPTO

Electricity Consumption

Electricity consumption in Greece increased steadily up to the peak of 58.8 TWh in 2008; followed by a 5-year period of decline, from 2009 to 2013, as a result of the prolonged financial crisis. The electricity consumption has recovered slightly in recent years, and in 2019 Greece consumed 52.1 TWh (see Figure 5.116) in the interconnected system (except of the islands, with 5.6 TWh).

Based on IEA data, the residential sector consumed the majority of electricity, accounting for 36% of total final electricity consumption in 2017, followed by the commercial (35.6%) and the industrial (22.7%) sectors. Other sectors (i.e. agriculture and transport) accounted for a smaller share of total final electricity consumption.

Figure 5.116 **Change in the Electricity Demand (GWh) in the Interconnected System of Greece, 2018-2019**



Source: IPTO

Non-Interconnected Islands

In Greece (mainly in the Aegean Sea), most islands currently obtain electricity from autonomous power generation plants, operating with diesel and fuel oil, and RES units (wind and photovoltaic). These islands have not yet been interconnected with the mainland grid, mainly due to technical and financial difficulties, since interconnections are capital-intensive projects. The electricity market of the Non-Interconnected Islands (NII) now consists of 29 autonomous systems, since Paros and Syros were interconnected in May 2018 and Mykonos in May 2019. Some of these systems comprise several islands (island clusters), and the operation and management of the NII market is undertaken by the Hellenic Electricity Distribution Network Operator (HEDNO) and more specifically by its Island Management Division. According to RAE data[21], peak demand varies among the 29 autonomous island clusters:

- peak demand in 19 "small" autonomous systems is up to 10 MW;
- peak demand in 8 "medium-sized" autonomous systems fluctuates from 10 MW to 100 MW; and
- peak demand in 2 "large" autonomous systems, namely Crete and Rhodes, is over 100 MW.

Electricity consumption in the NII varies correspondingly, from a few hundred MWh in the smaller islands (e.g. Antikythira, Agathonisi, etc.) to some TWh in the largest NII (Crete).

[21] http://www.rae.gr/site/categories_new/electricity/market/mdn.csp

As mentioned above, the NII are usually equipped with units that use diesel as fuel and are expensive, environment-unfriendly, and cannot benefit from the advantage of economies of scale. However, the NII feature excellent conditions for wind and solar energy utilisation.The operation of these types of energy in the islands is complicated by their variability and the need for back-up systems. Based on data provided by the HEDNO's Island Management Division, the total installed capacity of power generation units in the NII was approx. 2.2 GW in 2019, of which 79% concerned thermal stations (see Table 5.115), increased by 7.4% compared to 2018 levels (2,070.10 MW).

Table 5.115 **Installed Capacity (MW) of Power Generation Units on NII, 2019**

Categories	Installed Capacity (MW)	Percentage (%)
Thermal Stations*	1,756.97	79.0%
Wind Parks	306.15	13.8%
Photovoltaic**	129.75	5.8%
Special Program PV and net metering	27.15	1.2%
Biogas	0.99	0.0%
Hybrid	2.95	0.1%
Hydro	0.3	0.0%
Total	**2,224.26**	**100.0%**

*Last available data is for 2018; **Installed capacity of Special Program P/V and net metering is not taken into account. Source: HEDNO

Similarly, power generation in the NII was at approx. 5.6 TWh in 2019, of which 83% concerned thermal stations (see Table 5.116), recording a very slight drop in the range of 0.3% as compared to levels in 2018 (5,572 GWh).

Table 5.116 **Power Generation (MWh) in NII, 2019**

Categories	Power Generation (MW)	Percentage (%)
Thermal Stations	4,594,664.4	82.7%
Wind Parks	700,386.2	12.6%
Photovoltaic*	218,647.9	3.9%
Special Program PV and net metering	34,786.4	0.6%
Biogas	4,382.1	0.1%
Hybrid	1,696.6	0.0%
Hydro	859.3	0.0%
Total	**5,555,423.0**	**100.0%**

*Power generation by Special Program P/V and net metering is not taken into account. Source: HEDNO

(b) Planned New Projects

Of great significance are the developments regarding the electricity interconnections of the islands with the power grid in mainland Greece, and improved cross-border interconnections that will enable the national electricity transmission system to cover the requirements of the new targets for RES penetration and the incorporation of energy storage systems by 2030.

Indicatively, Greece's power grid operator IPTO has already announced the inclusion in its ten-year plan for the years 2021-2030 of the electricity interconnection of the North Aegean islands, to be realised at the same time as the interconnection of the Dodecanese. With regard to the country's international interconnections, IPTO's ten-year plan includes the construction of the second interconnector between the Greek and Bulgarian power systems, an upgrade of existing lines, and the development of new interconnections with the neighbouring systems of North Macedonia and Turkey. As already analysed, Greece has electricity interconnections to Albania, North Macedonia, Bulgaria, Turkey and Italy through a 400KV connection. IPTO is now taking initiatives to upgrade Greece's interconnections with neighboring countries, acknowledging transboundary grid link insufficiencies are having a negative impact whose consequences include market functional disorders and higher electricity prices.

The operator has formed working groups with all of Greece's neighboring countries to examine the prospect of constructing or reinforcing existing interconnections. These associations include cooperation with Italian operator Terna. The two sides, prepared to consider both an upgrade of the existing system or the development of a new one, estimate that the Greek-Italian grid interconnection requires a capacity increase of between 500 and 1,000 MW. IPTO and Terna have agreed to proceed with related studies for an optimal solution as soon as possible. The operators intend to reach a decision within the next few months. Any selection will need to be approved by the Greek and Italian regulatory authorities of energy.

The existing Greek-Italian electricity grid interconnection, a 163 km subsea cable with a 500 MW capacity in operation since 2002, was used to facilitate the Target Model's next stage, market coupling, beginning on December 15, 2020, with the aim of harmonizing the energy markets of the two countries. Regarding Crete's electricity interconnections, IPTO has left unchanged its completion target for the Crete-Attica grid interconnection, keeping it at June, 2023, in its new 10-year development plan covering 2022 to 2031[22], an update on the 2021-2030 plan delivered last March. The Crete-Attica interconnection is a landmark project in Greece. It is the largest energy project under construction and the second largest overall and it will contribute significantly in the process for economic recovery with a special positive sign for the economy of Crete, one of the most important economic regions in Greece.

Preliminary work on the aforementioned project began last summer, while significant steps have been made for the project's environmental licensing requirements, a procedure expected to be completed by the end of 2021. Expropriation procedures, including property purchases, needed for the installation of converter stations and overhead cables, are also anticipated to have been completed by the end of this year. Sound progress has been reported along this front.

In July 2020, the subsidiary of IPTO "Ariadne Interconnection" and Eurobank announced the signing of a loan agreement up to €400 million to finance the project of "Crete-Attica electrical interconnection" with a total budget of €1 billion. The common bond loan has a repayment period of ten (10) years with a possibility of partial withdrawals according to the implementation course of the interconnection. In addition to bank lending, the project will be implemented using equity of €200 million, while the co-finance of Greece and the European Union under the operational program "Competitiveness, Entrepreneurship, Innovation 2014-2020" or/ and its following program, will be used for the remaining €400 million.

A small-scale grid interconnection to link Crete with the Peloponnese is scheduled for completion at the end of March 2021, according to IPTO's updated ten-year development plan. According to IPTO, Crete's grid interconnection with the mainland will require the development of a new, upgraded regional energy control center on the island. The new center will be needed to ensure effective management of new energy market data, not achievable through the existing center's means and infrastructure, as these would not be able to incorporate new technologies. Also, the existing energy control center's maintenance has become extremely difficult and costly due to the unavailability of spare parts and experienced technicians for its type of technologies.

SOLID FUELS

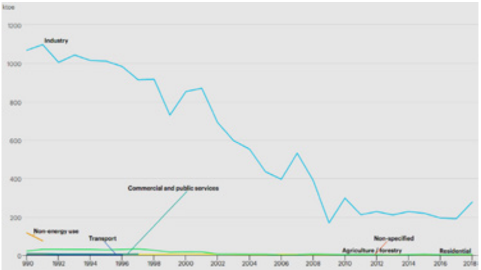
(a) Supply and Consumption

Historically, lignite has played a significant role in Greece's power generation and covered almost 20% of total electricity demand in the interconnected – except of the islands - system in 2019 and much higher share (more than 60%) in previous years. However, its dominance has been reduced in the last decade due to the fall in electricity consumption and the increased penetration of RES for power generation - mainly wind and solar - and natural gas. The contribution of lignite in power generation has declined considerably over the last two years, from 14.9 TWh in 2018 to 10.4 TWh in 2019.

In Greece, lignite accounted for 28.57% of total primary energy supply in 2009 and 14.85% in 2019, the third largest share after oil and natural gas. Lignite is Greece's only significant fossil fuel resource. Based on IEA's data, final lignite consumption in Greece stood at 6 ktoe in 2018.

[22] https://www.admie.gr/sites/default/files/nea-anakoinoseis/30-12-2020/%CE%A0%CF%81%CE%BF%CE%BA%CE%B1%CF%84%CE%B1%CF%81%CE%BA%CF%84%CE%B9%CE%BA%CF%8C%20%CE%A3%CF%87%CE%AD%CE%B4%CE%B9%CE%BF%20%CE%94%CE%A0%CE%91%202022-2031%20-%20%CE%9A%CF%8D%CF%81%CE%B9%CE%BF%20%CE%A4%CE%B5%CF%8D%CF%87%CE%BF%CF%82.pdf (in Greek)

Figure 5.117 **Final Lignite Consumption by Sector in Greece, 1990-2018**



Source: IEA (2020)

(b) Local Exploration and Production

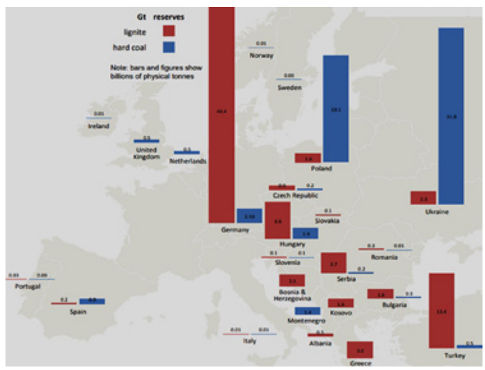
Based on data from the European Association for Coal and Lignite (EURACOAL)[23], lignite production in Greece amounted to 27.3 million tonnes in 2019. Based on IPTO's data, electricity produced from lignite declined considerably from 14.9 TWh in 2018 to 10.4 TWh in 2019, due to the increase in RES, lower total demand for electricity, and the high cost of emission rights, which makes power generation from lignite uneconomic.

Imported hard coal (approx. 0.4 million tonnes), almost all from Russia, is used in the cement industry.Total confirmed geological reserves of lignite in Greece amount to approx. 5 billion tonnes. These deposits are geographically dispersed across Greek territory[24]. Based on current technical-economic conditions, the deposits that are suitable for energy exploitation amount to approx. 3.2 billion tonnes and are equivalent to 450 million tonnes of oil. The main exploitable deposits are in the regions of Ptolemais, Amyntaio and Florina, with reserves estimated at 1.8 billion tonnes, in the area of Drama, with reserves of 900 million tonnes, and in the area of Elassona with 169 million tonnes.

There is also a lignite field with reserves of approx. 223 million tonnes in the area of Megalopolis, in the Peloponnese. Based on total exploitable lignite reserves in the country and the expected rate of consumption in future, it is estimated that these reserves are sufficient for more than 45 years. Up to now, mined quantities of lignite amount to 29% of total reserves. In addition to lignite, Greece has a large deposit of peat in the area of Philippi (eastern Macedonia). Exploitable reserves at this deposit are estimated at 4 billion cubic metres and are equivalent to approx. 125 million tonnes of oil.

In general, the quality of the Greek lignite is low. Thermogenic power is in the range of 975-1,380 kcal/kg in the areas of Megalopolis, Amyntaio and Drama, 1,261-1,615 kcal/kg in the Ptolemais area, and 1,927-2,257 kcal/kg in the areas of Philippi and Elassona. An important comparative advantage of lignite in Greece is the low sulphur content.

Map 5.37 **Exploitable Lignite Reserves in Europe**



Source: EURACOAL

Greece to Phase Out Lignite

According to the updated NECP of December 2019, all PPC's lignite-fired power plants are expected to be phased out by late 2023 (apart from the new one, Ptolemais 5, currently under construction, which is expected to be phased out in 2028), with a total capacity of approx. 4 GW, and all lignite mines in the regions of western Macedonia and Megalopolis are set to be closed.

The fuel that drove the country's electrification is gradually being phased out, in line with EU policy and the country's commitments. The first PPC's lignite units (i.e. Amyntaio and Kardia) were closed in 2020 and a Master Plan for the way ahead is now ready. The Master Plan includes strong tax and development

[23] EURACOAL (2020), "Market Report 2020 no. 1"
[24] https://www.dei.gr/el/oruxeia/apothemata-kai-poiotita

incentives and emphasis on manufacturing, tourism and green energy, to ensure a smooth transition to the post-lignite era for the regions of western Macedonia and Megalopolis.

In February 2020, the Inter-Ministerial Committee responsible for the lignite phase-out appointed Mr. Kostis Mousouroulis, a senior official of the European Commission, as Coordinator of the Just Transition Development Plan (SDAM) for the regions of western Macedonia and Megalopolis. More specifically, the Ministerial Council Act states that Mr. Mousouroulis will be the Chairman of the Coordination Committee, i.e. the Working Group, which, under the supervision of Inter-Ministerial Committee, will draw up and implement the Just Transition Plan and will coordinate the activities related thereto, starting in 2020. It is worth noting that IENE recently completed a special Report[25] on behalf of the SDAM Coordination Committee about the current situation and the prospects of regions in energy transition in Greece.

The proper transition of lignite regions into an era of clean energy, development and business growth requires financing in several sectors. What is sought is financial assistance for infrastructure projects and support for fast-track investments in RES, energy efficiency and electromobility, projects to support and strengthen the primary sector, and other projects that promote innovation and competitiveness.

Attaining these aims will require full and productive utilisation of all available financing means and sources for the transition into the post-lignite era. In particular, the investments under consideration will enable full utilisation of the resources of the three pillars of the Just Transition Mechanism (Just Transition Fund, Special InvestEU status, Public Sector Credit Facilities), while also advancing the financing of investments via the other sources, by mobilising considerable private capital (leverage).

Table 5.117 **Timeframe for Shutting Down Lignite-fired Plants in Greece**

Lignite-fired plant	Rated capacity	Year of shutdown
Kardia 1	275	2019
Kardia 2	275	2019
Kardia 3	280	2021
Kardia 4	280	2021
Agios Dimitrios 1	274	2022
Agios Dimitrios 2	274	2022
Agios Dimitrios 3	283	2022
Agios Dimitrios 4	283	2022
Agios Dimitrios 5	342	2023
Amyntaio 1	273	2020
Amyntaio 2	273	2020
Florina/Meliti	289	2023
Megalopolis 3	255	2022
Megalopolis 4	256	2023

Source: IEA (2020)

In this context, initiatives are being planned and developed to utilise all financing means and tools. At this point, it is worth noting that the aim is fast-track implementation of the investments, with a considerable part thereof being realised in 2022 and 2023. The total time allocation of the investment cost will depend on several parameters, such as approval of the incentives by the European Commission, land restoration, public investments and other supportive programs and projects, simplification of licencing procedures, etc. Prompt finalisation of the incentives will be significant for the unimpeded and timely implementation of the investment plans. At the same time, land restoration works impact directly the timing of the investments, due to both the financing costs they involve and the fact that they constitute a precondition for implementing some of the investments.

In addition, the realisation of public investments, especially on the level of infrastructure, will increase considerably the attractiveness of the areas and the capability to accommodate new investment plans, while the maturity of the project's studies in conjunction with the completion of Special Urban Planning and the acceleration of the licencing procedures will contribute decisively to fast-track implementation of the financing plan.

[25] IENE (2020), "Current Situation and Prospects for Areas in Energy Transition in Greece", IENE Study (M58)

It is worth noting that taking into consideration the investment plan as envisaged at this stage, which will obviously be enriched with new investments over time, the total capital cost of foreseen investments (which are initially estimated at more than €5 billion), the parameters of each financing source and the need to adopt the best possible financing scheme, the initial plan for the financing has as follows:

- 10% subsidies, by turning to account the first pillar of the Mechanism (Just Transition Fund)
- 30% loans on favourable terms, by using the other two pillars (Special InvestEU status, Public Sector Credit Facilities) and other financing tools
- 40% commercial loans, by drawing financing from domestic and international credit institutions
- 20% equity capital, by mobilising and attracting the private capital of candidate investors.

This financing scheme indicates that a considerable part of the investments will be realised through leverage of commercial (bank) loans and equity capital, since important investments that are already mature do not require further support.

In parallel, utilising the Just Transition Mechanism, not with the aim of exhausting immediately the subsidies (Just Transition Fund) but rather by making the fullest possible use of all three pillars, will allow the incorporation and implementation of an increasing number of investments. Indicatively, in July 2020, the state's Green Fund approved the first two calls for submitting proposals for financing "green" actions, with beneficiaries being the lignite-dependent municipalities of Amyntaio, Florina, Eordaia, Kozani and Megalopolis. The first call concerns the submission of Action Plans for Energy and the Climate and the second call concerns the financing of interventions for promoting the cyclical economy, with positive social and environmental impact, in the context of the National Strategy for the Cyclical Economy.

In August 2020, the Green Fund approved the third successive call for submitting proposals for financing "green" actions, in the context of its first-ever program for phasing out lignite. The call aims at the preparation of the related studies and planning and licencing procedures for the comprehensive management system for the pilot program of cyclical liquid waste management in these areas. The beneficiaries of the Program include the Region of western Macedonia and all First-Degree Local Authorities in the Kozani and Florina Regional Units. The total budget made available with this Call amounts to €1 million, with a minimum budget of €100,000 for each proposal. The ultimate goal is to promote a comprehensive model for the cyclical management of urban waste from towns and villages in the Kozani and Florina Regional Units of the western Macedonia Region. More specifically, there will be support for developing comprehensive systems for urban waste management, so that the waste sludge produced is processed towards converting it into an environment-friendly renewable fuel and/or a secondary material that is useful and safe for humans and the environment.

(c) Planned New Projects

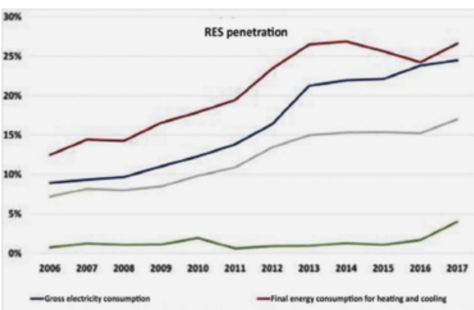
There is no planned new coal/lignite project in Greece. Ptolemaida V is the only lignite-fired power plant, operated by PPC, which is currently under construction. The plant, expected to be completed in 2022, is initially planned to operate as a lignite-fired power station for a six-year period before switching to another fuel or fuels. All options are being left open, meaning that, beyond 2028, Ptolemaida V could run on gas, biomass, waste-to-energy or a combination of these energy sources. Japan's Mitsubishi, providing the new facility's electromechanical equipment, was commissioned, some time ago, to conduct a study determining the optimal choice of fuel for Ptolemaida V beyond 2028. Continued use of lignite, after 2028, at Ptolemaida V has also been tabled as a possibility if carbon capture, utilization and storage (CCUS) technology is applied for a zero net carbon footprint.

RENEWABLES

(a) Overview of Sector's Development

The contribution of RES in energy consumption in Greece has shown a significant increase over the period 2006-2017, as their overall contribution in 2017 as a share of gross final energy consumption amounted to 17%, more than doubling the corresponding share in 2006 (see Figure 5.118), based on NECP's data. Apart from the transport sector, in which the share of RES recorded marginal variations and a stable increase only in 2016 and 2017, the contribution of RES in both gross electricity consumption and final energy consumption for heating in the period 2006-2016 increased considerably, at an average annual rate near 10%. It is worth noting that the variations observed in different periods in the share of RES in final energy consumption for heating are exclusively due to the use of solid biomass, which has fluctuated over recent years, following its sharp increase in the early 2010s and its peak in 2012.

Figure 5.118 **Total and Specific Shares of RES in the Greek Energy System on the Basis of EU Methodology, 2006-2017**



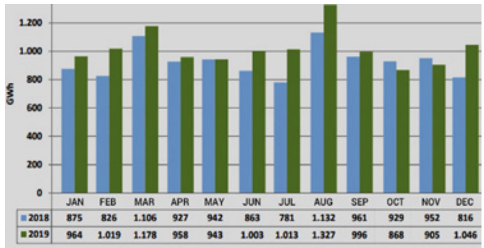
Source: NECP

Based on NECP's data, the share of RES in domestic gross electricity consumption in 2017 was 24.5%, a marked increase as compared to 2006, when the respective share was in the range of 9%. More specifically, regarding power generation from RES with non-controllable production features, i.e. power generation from photovoltaic and wind units, the percentage already amounts to over 15% in gross final electricity consumption.

Power Generation from RES

In Greece, power generation from RES in the interconnected system amounted to 12.2 TWh in 2019, up from 11.1 TWh in 2018, as a result of the fast growth of the installed capacity of wind and solar and the reduction in total electricity supply over the last decade.

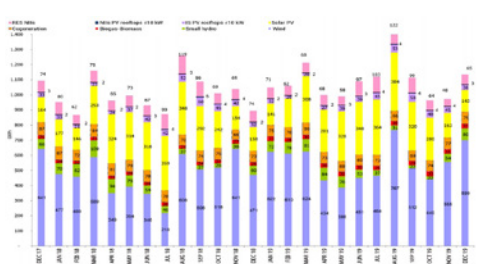
Figure 5.119 **Power Generation from RES in Greece, 2018-2019**



Source: IPTO

Total power generation in Greece from wind forms interconnected to the system amounted to approx. 6.6 TWh in 2019, and from small hydro units and biogas-biomass stood at 690 GWh and 362 GWh respectively. In addition, the total power generation from cogeneration units and assigned cogeneration interconnected system units stood at 186 GWh and 876 GWh respectively. The electricity generation from solar PV units in the interconnected system was almost 3.2 GWh in 2019 (see Figure 5.120).

Figure 5.120 **Power Generation of RES and Cogeneration (GWh) Units and Rooftop Photovoltaic Power Stations ≤10 kW, 2017-2019**



Source: LAGIE (Hellenic Electricity Market Operator)

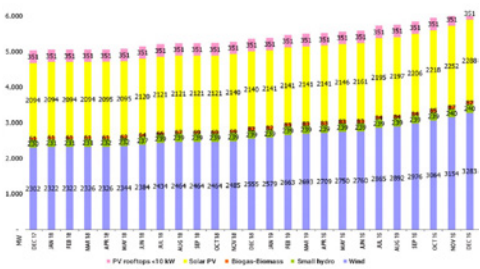
Greece has significant RES potential, which can contribute substantially to an environment-compatible restructuring of its energy system.

This potential mainly comprises solar, wind, hydro and geothermal energy as well as biomass. The ample wind potential is mainly found in the country's island regions (e.g. Crete, Aegean Sea, Evia, etc.), where most wind farms are currently located. The exploitation of Greece's wind potential, in conjunction with improvements in the technologies used in state-of-the-art wind turbines, is expected to contribute significantly towards sustainability.

Installed Capacity from RES

Based on data from the bulletin of the Renewable Energy Sources Operator & Guarantees of Origin (DAPEEP) of December 2019[26], the total installed capacity of RES units operating in the Greek interconnected system and of rooftop photovoltaic units smaller than 10 kW amounted to 6,249 MW in 2019 (see Figure 5.121), of which the majority is based on wind (52.5%) and photovoltaic (36.6%) units.

Figure 5.121 **Installed Capacity (MW) of RES Units Operating in the Greek Interconnected System and Rooftop Photovoltaic Units ≤10 kW, 2017-2019**



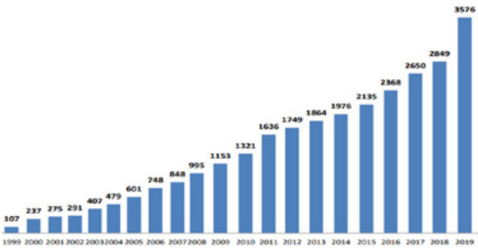
Source: LAGIE

During 2005-2019, the installed capacity of onshore wind farms increased almost six-fold, and more than 2.9 GW of new power capacity were added to existing plants in Greece (see Figure 5.122).

2019 - A Record Year for Wind Energy in Greece

2019 was a record year for wind energy in Greece, since 727 MW of new wind farms were connected to the network, almost four times the annual average during the previous decade (185 MW). In addition, the largest wind farm complex, with a capacity of 154.1 MW, was connected in South Evia (Kafireas) by Enel Green Power.

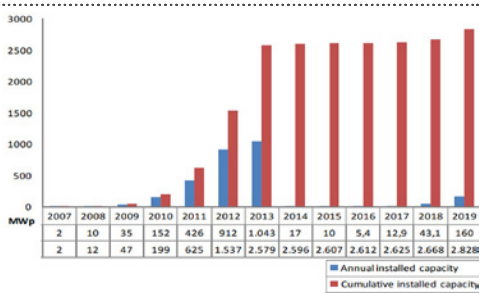
Figure 5.122 **Installed Capacity (MW) of Onshore Wind in Greece, 1999-2019**



Source: Hellenic Wind Energy Association

It is worth noting that the sharp increase of solar PV projects in Greece during the period 2011-2013 was due to the greater financial incentives for these type of investments. However, this short-lived increase resulted in a long-term and substantial rise in consumers' electricity bills, due to higher special taxes for RES levied on consumers. The entities shaping energy policy in Greece were concerned about this development and reacted by blocking new solar PV projects, even if they required only a small percentage of compensation compared to past projects. In 2019, the domestic solar PV market showed the first substantial indications of recovery, and the trend is towards an imminent return to figures in the range of hundreds of MW annually. In the past year, autoproduction systems increased by 3.1% compared to 2018, still at levels considerably lower than the country's potential. For another year, the solar PV market covered approx. 7% of Greece's electricity needs, placing the country in the fourth position globally (after Honduras, Italy and Germany) regarding the contribution of solar PV in total electricity demand.

Figure 5.123 **Installed Capacity (MW) of Photovoltaics in Greece, 2007-2019**



Source: HELAPCO

[26] http://www.lagie.gr/fileadmin/groups/EDRETH/RES/20200326_DELTIO_APE_DECEMBER.pdf

Table 5.118 **New Installed Capacity (MW) of Photovoltaics in Greece, 2019**

New installations that interconnected within 2019	Number of systems	Power (MWp)
Solar PV parks	246	150,29
Net Metering	362	9,57
Special Solar PV programme (expired 31.12.2019)	17	0,16
Total	625	160,02

Source: HELAPCO

Net-metering is one of the tools for promoting autogeneration and autoconsumption using RES. Net-metering allows the consumer to cover a substantial part of his autoconsumption, while also providing him with the capability to use the network for indirect storage of the green energy. However, the number of autoproduction projects remains small compared to the country's potential: the number of net-metering units was 362 in 2019, with a total installed capacity of 9.57 MW, while only approx. 10% of autoproduction systems has been installed in the residential sector, by the criterion of installed MW.

RES in Non-Interconnected Islands (NII)

As discussed earlier, there are currently in operation 29 autonomous island systems in Greece. In these NII, there must be a special focus on using RES for power generation, since there is high potential for their use and they are economically advantageous, since in most NNI both the final average power generation costs and the corresponding variable costs of oil use are very high. In addition, the European Directive 2015/2193/EU has come into force for limiting emissions of pollutants from medium-sized combustion plants for power generation, which will ultimately lead to their elimination from the NII.

However, the penetration of RES generation is subject to specific limitations, which are mainly determined by the technical minima of installed thermal units and the maximum permissible hourly penetration of non-controllable RES on the basis of load.

Total RES penetration in the NII is currently close to 21% of power generation, though without capability for further substantial penetration if the above limitations are not addressed, mainly through the application of innovative management technologies, utilising the technology of modern-day RES units with power electronics and/or with the installation and operation of storage systems. However, as a first step, HEDNO is in the process of readjusting its planning for developing state-of-the-art NII electricity systems, with higher RES penetration, modernisation and digitalisation of its infrastructure in the 29 non-interconnected island systems[27].

A special case are the many uninhabited islands and islets in Greek territory, which have very high wind potential and where wind and solar PV parks could be installed.

The promotion of the use of hybrid stations with RES, i.e. RES and storage, is another solution in cases where the electricity interconnection of the islands is not economically viable, but such stations will have to be assessed as to technical-economic factors and compared to the existing situation, and their installation and operation can be promoted only if it is ensured that power generation costs are reduced in total in the autonomous system involved each time and as compared to other mature solutions. Research concerning the operation of such stations at pilot application is necessary, and already several such projects are at an advanced stage of development. However, the framework for their support must be planned so that no stranded assets are created, demanding further support and subsidies from outside the electricity market, while the possibility of future interconnection of each island with the mainland grid and the impact on the operation and operational reinforcement of hybrid stations must also be taken into consideration. One parameter that will have to be taken into account in the country's energy planning is the ad-hoc studies for the final solution in each island system and the update of spatial planning for the RES in NII, so that any further

[27] http://dda.gr/pfiles/a58762e2c76300cedc96984520d1bb7512b13507.pdf

penetration of RES can be promoted without obstacles and additional regulatory and licencing-related delays.

(b) Latest RES Legislation

On May 5, 2020, the Greek Parliament passed a law modernising environmental legislation and harmonising Greek law with EU Directives 2018/844/EU (amending the directives on the energy performance of buildings and energy efficiency) and 2019/692/EU (amending EU Directive 2009/73/EC concerning common rules for the internal market in natural gas). This new Law 4685/2020 (OJ A' 92/2020) contains legislative measures which will significantly amend, standardise and simplify the current licensing procedure for renewable energy power plants – particularly the procedure for obtaining a renewable energy source (RES) production licence and an environmental approval.

New RES Production Certificate

One of the most important changes introduced is the replacement of the production licence with a certificate. The Regulatory Authority for Energy (RAE) is authorised to issue these certificates, but the law provides for the possibility of a future ministerial decision delegating this authorisation to another person or authority.

Applications for issuing a certificate must be submitted via the electronic register, which will be established according to the provisions of the new law. Each year there will be three application rounds, which will take place during the first 10 days of February, June or October. The new law envisages two different application procedures and subsequently two different types of certificate: one for special projects and one for all other RES projects.

Simplified Environmental Licensing Procedure

Furthermore, the new law introduces various provisions that aim to simplify and expedite the environmental licensing procedure (including the renewal and amendment of the environmental approvals), as experience has shown that the respective deadlines envisaged in the pre-existing legal framework are seldom met. Thus, the environmental approvals will be valid for 15 years, instead of 10, on the condition that the circumstances under which they were issued remain unchanged. The deadlines for completing the environmental licensing process, with the exception of the public consultation deadlines, are significantly reduced, and certain stages of the procedure have been merged. It is also noteworthy that a request on behalf of the authorities for the submission of supplementary data by the applying project operator does not constitute a reason for the authorities to delay the evaluation of the file submitted.

(c) Planned New Projects

The aforementioned simplification of the licensing procedure for RES projects will play an important role in their deployment over the next years. Energy infrastructure also plays a key role in the high penetration of RES plants for power generation, and therefore the design and development of new projects by the operators will incorporate the projections for the penetration of new RES plants and will lay down the necessary adjustments and actions to ensure that its implementation is as seamless and efficient as possible for the functioning of the energy system.

A large increase in installed capacity will be required to make possible a higher RES share in the energy mix. Distribution networks will have to be constructed also in a generation-oriented, not just consumer-oriented, manner from now on. The operators of both the transmission systems and of the distribution network should design the networks with due account taken of future RES development, increasing geographical coverage and strengthening and modernising technologically the high and ultra-high voltage transmission systems and distribution networks, provided that there is a clear-cut regulatory framework in place which can be used to determine the growth rate of RES, the operator's obligations, the cost recovery method, etc. The networks should, therefore, be developed in a way that ensures maximum RES penetration and minimizes potential cuts in energy generation.

In this context, the best technical and cost-effective enhancement and expansion of energy infrastructure in both the transmission system and the distribution network for tackling congestion that prevents further growth of RES plants in specific areas will also be, for the following period, a core measure for the optimal integration of RES in energy networks.

Moreover, the development of new financing models to speed up the development of this infrastructure will be launched, whereas management complexity and time lags due to external factors will be limited through more effective planning and transparent consultation procedures. In the above context, energy network operators will examine the interventions planned and identify the costs required for both the required infrastructure and the balancing needs for the operation of these plants.

According to Greece's NECP, RES investments are expected to reach a total of €9 billion by 2030, not including new grid interconnection projects. The share of RES in Greece's energy mix is anticipated to reach 65.7% in 2030 from 32.6% in 2019, in terms of overall electricity production, primarily through new investments in wind and solar energy.

Installed wind energy capacity is projected to reach 7 GW in 2030 from 3.6 GW at present. This category's total is seen increasing to 4.2 GW by 2022, 5.2 GW by 2025, and 6 GW by 2027 before hitting the projected level of 7 GW in 2030. Similarly, installed solar energy capacity is seen rising to 7.7 GW from 3 GW at present. The total solar capacity is expected to reach 3.9 GW by 2022, 5.3 GW by 2025, 6.3 GW by 2027 and 7.7 GW by 2030.

ENERGY EFFICIENCY AND COGENERATION

(a) Energy Efficiency

Greece has applied a wide range of energy efficiency policies in recent years, most of which are based on adapting the requirements of the European Commission Directive on Energy Efficiency to the Greek legislation. The policy measures applied in the past did not result in substantial energy savings as envisaged initially, due to the economic and financial crisis, low public awareness, inadequate data and lack of financing.

In recent years, Greece has made substantial progress in promoting energy efficiency in buildings, which can be summarised as follows:

- The Greek Regulation for the Energy Efficiency of Buildings (KENAK), which determines the minimum energy efficiency requirements for buildings
- Designating buildings as being of almost zero energy consumption
- Introducing a system of Energy Inspections and the issue of Energy Certificates
- Planning a long-term strategy for renewing building stock
- The "Saving at Home" publicly financed program
- The energy upgrade of public buildings through specific actions, such as the first Energy Saving program for Local Authorities, etc.

Improving energy efficiency in all fields of consumption is the biggest challenge for the public policies to be implemented in the following decade. Therefore, it is an absolute and horizontal priority that should cover the entire scope and mix of policies and measures to be adopted. Energy savings achieved through improved energy efficiency have a direct impact on how energy is consumed, on the technologies used and on meeting consumer energy needs, also making a substantial contribution towards improving the competitiveness of all industrial activities.

According to the NECP, the objective is to improve energy efficiency in final energy consumption by at least 38% in relation to the foreseen evolution of final energy consumption by 2030, as estimated in 2007 in the context of the EU energy policies; thus, resulting in final energy consumption levels of not more than 16.5 Mtoe in 2030. There is also satisfactory performance in terms of the relevant evaluation indicators concerning the rate of reduction both with regard to final energy consumption for 2017 (16.8 Mtoe) and the energy savings target for 2020 (18.4 Mtoe), taking into account the increase in final energy consumption in order to reverse the impact of the economic recession of the previous years.

This rate of reduction is even higher if adjusted to primary energy consumption, in which case it stands at more than 43%. This demonstrates that the overall objective is to achieve an improvement in energy efficiency across the entire energy system, attaining a particularly high level of improvement in terms of how energy is made available for consumption, always in the most cost-effective way. An additional objective is set in respect of the cumulative amount of energy savings to be attained over the period 2021-2030 in accordance with Article 7 of Directive 2012/27/EU on energy savings obligations. According to the available final energy consumption figures, cumulative energy savings of at least 7.3 Mtoe should be achieved over the period 2021-2030. However, the objective will be re-calculated on the basis of the final energy consumption figures for the years 2016-2018. In addition, an objective is set for the annual energy renovation of a total floor area of the thermal zone of central public administration buildings equal to 5,400 square meters, representing just 3% of the total floor area.

The need to renovate the existing building stock is indisputable, as this will result in significant energy savings and in cost savings for citizens, and will also improve the comfort, safety and health conditions in the use of these buildings. To that end, it is necessary to establish a central quantitative objective for the renovation and replacement of residential buildings with new nearly zero-energy buildings, which could in aggregate amount to 12%-15% of all residential buildings by 2030. The objective is to have an average of 60,000 buildings or building units upgraded each year in terms of energy and/or replaced with new more energy-efficient ones. This particular objective will contribute significantly to the major upgrading of the ageing building stock, while at the same time providing a substantial boost to the construction industry through high added value technologies and essentially ensuring increased financial and operating benefits for households in Greece, also enabling them to cover their energy needs. Moreover, in respect of this dimension as well as other dimensions of the NECP, the aim is also to increase the use of natural gas in final consumption. More specifically, natural gas is expected to be the intermediate fuel for switching to a low GHG emissions model in all final consumption sectors, and may also lead to both improved energy efficiency and lower energy costs compared to other conventional technologies. A key aim is to achieve a higher gas share in all final consumption sectors and, essentially, to ensure that its increased use replaces part of the current consumption of petroleum products in these sectors.The development of the necessary transmission and distribution infrastructure to allow access to natural gas for higher percentages of end users in the building sector and the further increase in its use in industry and transport are priorities for the forthcoming period. The quantitative objective for this priority is to increase the direct use of natural gas in the final consumption sectors by at least 50% compared to 2017.

Finally, the implementation of all the necessary investments in final energy consumption sectors with a view to improving energy efficiency requires that more effective financing mechanisms are planned in order to increase and maximise the current levels of private capital leverage. The active involvement of the financial sector and the promotion of innovative financing mechanisms and market mechanisms, including energy performance contracts, are critical parameters for attaining this objective.

Energy Efficiency in Buildings

Since buildings are currently responsible for approximately 40% of energy consumption, there is a need to promote the improvement of the energy efficiency of buildings through renovation and modernisation, as well as to adopt corresponding measures for renewing the stock of end-of-lifecycle buildings, while at the same time using construction and demolition waste in conformity to the principles of circular economy. Reducing the energy consumption of buildings requires the increased use of energy-efficient and low-emission heating systems and the renovation or construction of smarter buildings, with improved insulation materials, inter alia, in full conformity to the principles of circular economy. The Energy Performance of Buildings Directive contributes to improved quality of life and makes a significant contribution towards the reduction in GHG emissions by 2050.

Another highly important policy is the optimal use of RES technologies to cover heating and cooling needs and of RES autoproduction systems to cover the needs of buildings for electricity, also by strengthening the role of consumers. These actions will also ensure a lower cost of living. However, the necessary methods and means must be provided, to help people make this transition. Improving energy efficiency in buildings has much potential for speeding up energy savings and contributing to the recovery of the economy after the Covid-19 pandemic.

Building on the momentum of the Renovation Wave initiative[28], there is scope for Greece to intensify efforts to improve the energy performance of the building stock with specific measures, targets and actions, while giving due attention to energy poverty. Further support for the renovation of public and private buildings could be provided through increased public funding and by leveraging EU and national budgets with private money, combining grants, lending, guarantees and loan subsidies. Greece is expected to provide a robust and comprehensive long-term renovation strategy, in accordance with Article 2a of the Energy Performance of Buildings Directive, which can contribute to the energy efficiency target and the recovery of the Greek economy following the Covid-19 pandemic.

The long-term renovation strategy is due to define a roadmap for decarbonisation by 2050 with ambitious milestones for 2030, 2040 and 2050, measurable progress indicators, expected energy and wider benefits, measures and actions to renovate the building stock, and a solid finance component with mechanisms to mobilise public and private investment.

Energy Efficiency in Transport

In the transport sector, the use of vehicles powered by alternative fuels and electricity, the sharp drop in unit energy consumption per type of vehicle, the use of second-generation biofuels, the complete electrification of railway infrastructure and the increase in the share of track-based modes of transport in the overall transport work will, by the end of the next decade, totally transform the technological structure and fuel mix used in the transport sector, thus impacting the national economy as a whole. Finally, given that Greece is a leader in shipping, it is important to promote emission reduction technologies in shipping in compliance with the decision of the International Maritime Organisation (IMO) of April 2018 for a 50% reduction in emissions by 2050, compared to 2008, and totally eliminating emissions by 2100.

(b) Cogeneration

Cogeneration is defined as the simultaneous production of power and heat (and/or cooling) from the same initial energy source. In general, cogeneration systems can cover all final energy uses (electricity, heating, steam production, cooling) and thus, they are used across a broad range of applications (e.g. greenhouses, residential complexes, manufacturing facilities, etc.). In addition, these systems allow for the dispersal of power generation units so that they reflect the needs of local consumption, offering high performance, avoiding losses in transport and increasing the flexibility of an area's power system.

The fuel most commonly used in cogeneration systems is natural gas, which, compared to other fossil fuels, has lower greenhouse gas emissions. In specific applications, as in agriculture companies, biomass may also be used. Greece has one of the lowest rates of cogeneration among the EU-28 member

[28] European Commission (2020), "A Renovation Wave for Europe – greening our buildings, creating jobs, improving lives", COM(2020)662 and SWD(2020)550, https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1603122220757&uri=CELEX:52020DC0662

states, even though it has a 40-year related tradition, initially in the industrial sector. In 2019, the total installed cogeneration capacity and distributed cogeneration units throughout the country was 233.4 MW, based on DAPEEP's data, which covers mostly the industrial sector, the primary and tertiary sectors as well as the district heating of towns. An appropriate legal framework can promote cogeneration, in conjunction with support of mechanisms for autoproduction, but Greece is lagging in long-term stability.

Also, the related legislation is characterised by complexity (e.g. frequent changes in energy laws, amendments, etc.), while the bureaucracy in licencing procedures is an obstacle for any investor wishing to become active in the sector.

Table 5.119 **Annual Electricity Generation from Cogeneration and RES in Greece, 2010-2019**

Year	Annual Electricity Generation from Cogeneration Units	Annual Electricity Generation from Distributed Cogeneration Units	Total Electricity Generation from RES and Cogeneration	CHP % of the Total
	GWh	GWh	GWh	%
2010	115	0	3,256.5	3.53
2011	142	0	3,959.5	3.59
2012	149	0	5,406.5	2.76
2013	119	943	9,156.0	1.30
2014	159	1,116	9,091.0	1.75
2015	188	1,121	10,051.0	1.87
2016	185	1,112	10,469.0	1.77
2017	195	984	11,552.0	1.69
2018	183.5	918	12,211.5	1.50
2019	186.5	876	13,357.5	1.40

Source: Hellenic Association for the Cogeneration of Heat and Power (HACHP)

According to studies undertaken before the financial crisis, there are significant prospects for cogeneration in several sectors of the Greek economy, e.g. in industry, in district heating from cogeneration units, in the primary and tertiary sector (hospitals, hotels, etc.) that can be financed by EU funds (e.g. via the Structural Funds and Cohesion Fund), but also for very small cogeneration for buildings. According to the Cogeneration Observatory and Dissemination Europe, the potential of Greece is estimated at 11.1 TWh/year of primary energy saving, as per the methodology of the Directive on Energy Saving (27/2012/EC). Considering the implementation of the aforementioned actions possible, the Observatory estimates the potential at 24 TWh/year of primary energy saving and the reduction of CO_2 emissions at 14 million tons.

Table 5.120 **Electricity Cost from Cogeneration and RES in Greece, 2010-2019**

Year	Cost for Cogenerated Electricity from Cogeneration Units and Distributed Cogeneration Unit, million €	Total Cost of Electricity from RES and Cogeneration, million €	CHP % of Total Cost
2013	67.1	1,747.5	3.84
2014	56.6	1,638.4	3.45
2015	56.2	1,476.4	3.81
2016	41.1	1,329.0	3.09
2017	38.5	1,691.4	2.28
2018	37.3	1,719.5	2.17
2019	42.6	1,848.8	2.30

Source: Hellenic Association for the Cogeneration of Heat and Power (HACHP)

(c) Planned New Projects

Launched in November 2020, the "saving-autonomous" programme (old "Saving at Home" programme) is currently seeing strong interest from homeowners. The programme has an €850 million budget and is intended at enabling around 600,000 homeowners to make their houses more energy efficient by 2030. The scheme enables homeowners to include the installation of a rooftop PV system, a residential battery, a smart power management system, and a charger for electric vehicles.

These and other interventions, such as thermal insulation, windows replacement, and the use of thermal solar collectors, are intended at reducing the energy consumption of all interested houses by around 9%. The funds for the programme are being provided by the EU's National Strategic Reference Framework (NSRF) for 2021-2027. Another important energy efficiency programme is the "Elektra programme", which strengthens the energy upgrading of public buildings by financing part of the required investments through investment loans, which will be repaid by the programme. It also provides for the participation of energy service companies, whereas payments to them, in the context of energy performance contracts, are guaranteed through securities.

Energy Investment Outlook

Taking into account large- and medium-sized energy projects already under development, but also assessing the dynamics of implementing planned projects, Greece appears to have a substantial energy related investment potential. This is currently estimated at above €45 billion over the next decade or about €4.5 billion on an annual basis.

As analysed in IENE's 2020 Annual Report on Greece's Energy Sector[29]. Table 5.121 summarises the anticipated energy investments in Greece over the next decade (2020-2030). These estimates are based on several assumptions, including that from 2021 and onwards the country will record growth, not recession, with an annual growth rate of 1.5%. More details about Table 5.121 are available at iene.eu.

Table 5.121 **Anticipated Energy Investments in Greece, 2020-2030**

	Expected Investments in million €
Oil	7,700
Natural Gas	2,800
Electricity	21,200
Energy Efficiency	11,000
Residential and Commercial Solar Power Applications	1,500
Research & Innovation	1,000
Total	**45,200**

Source: IENE

[29] IENE (2020), "The Greek Energy Sector – Annual Report 2020", https://www.iene.eu/articlefiles/greek%20energy%20sector%20study%202020_eng%201.pdf

HUNGARY

Hungary

Economic and Political Background

A second GDP release confirmed that the pace of economic contraction in Hungary moderated considerably in the fourth quarter of 2020, with GDP falling 3.6% year-on-year (previously reported: -3.7% y-o-y), following the 4.6% drop recorded in the previous quarter. Meanwhile, GDP expanded 1.4% on a seasonally-adjusted quarter-on-quarter basis in Q4 (previously reported: +1.1% q-o-q), following Q3's 11.0% rebound, which had marked the strongest expansion on record. Looking at the year as a whole, the economy shrank a heavy 5.0%, strongly contrasting 2019's 4.6% expansion.

Looking at the details of the release, while the external sector benefited from an improved international trade environment, the performance of the domestic economy was more mixed. Household consumption dropped 4.2% in annual terms following Q3's softer 2.1% decrease, amid downbeat consumer sentiment and tighter Covid-19 containment measures. However, fixed investment rebounded and grew 1.2% in the fourth quarter (Q3: -13.7% y-o-y), reflecting increasing investment in construction and in machinery and equipment. Meanwhile, public spending soared 6.2% (Q3: -2.6% y-o-y) amid the government's efforts to boost the economy.

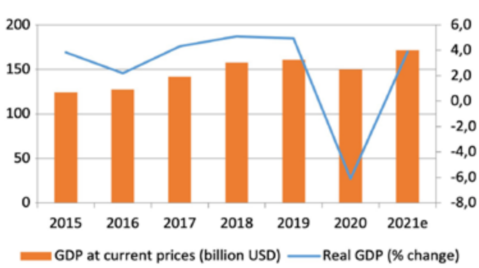
On the external front, exports of goods and services expanded 1.7% in Q4 (Q3: -4.8% y-o-y), as easing lockdowns abroad supported foreign demand. Similarly, imports of goods and services increased 0.9% in Q4, following Q3's 4.5% plunge. Looking ahead, the economy is set to rebound markedly in 2021 following last year's pandemic-induced downturn. Domestic and foreign demand should strengthen amid loose fiscal and monetary policy stances, incoming EU funding and the gradual reopening of the global economy. Uncertainty regarding the availability of vaccines poses a downside risk, however.

IMF estimates that Hungary's GDP will expand by 3.9% in 2021, significantly higher than -6.1% in 2020.

In recent weeks, a new challenge has emerged in the continuing fight against Covid-19. A significant portion of Hungarians are not convinced of the importance of vaccination or are afraid of the alleged side effects of the vaccines. The first part of the task has been completed by the government, as it had been able to secure the supply of vaccines from various sources. However, if the vaccination rate cannot be accelerated due to public reluctance, the government would risk a second year of lockdowns. This would further deteriorate the business environment and affect the overall assessment of the government's performance, which of course could be reflected in the 2022 general elections.

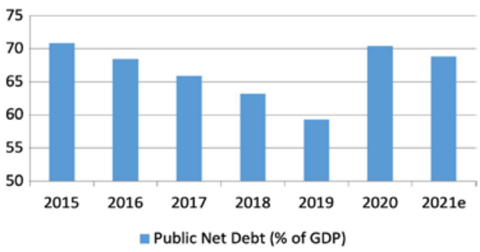
In other words, the opposition camp has a political stake in the mismanagement of the Covid 19 crisis now. This is why political debates in Hungary still revolve around the details of the vaccination, including the origin of the vaccines, their reliability and safety. This briefing first focuses on to the details of these debates (vaccination readiness, the origin of vaccines) and the details of a new round of lockdown, then moves on the analysis of the latest polling data.

Figure 5.124 **Hungary's GDP and its annual GDP growth**



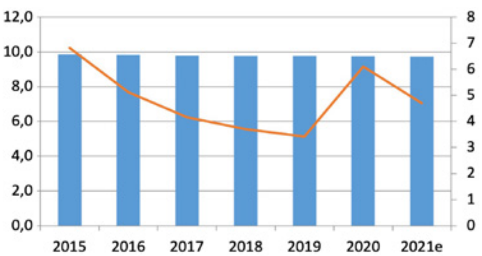
Source: IMF World Energy Outlook (October 2020)

Figure 5.125 **Hungary's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.126 **Hungary's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

(a) National Energy Policy

A series of documents, such as the National Energy and Climate Plan in line with the requirements of the EU or the Report on the Impact of Climate Change on the Carpathian Basin, along with the National Climate Change Strategy and the derived National Action Plan Addressing Climate Change in line with the requirements of the UNFCC, provide the strategic basis for Hungary's climate mitigation actions. The National Energy Strategy 2030 with an Outlook to 2040 document, approved in 2020, replacing the previous document of 2011, provides the strategic basis and defines the energy- and climate policy priorities of the country.

The strategy is laid with the binding EU 2030 goals in mind, and among others is designed to attain a number of policy goals while ensuring energy sovereignty, decarbonization of energy production through the utilization of nuclear and renewable technologies and maintaining sustainable energy prices. These policy goals can be described as follows:

- The final energy consumption of Hungary -in parallel with strong economic growth- should not exceed the 18,7 Mtoe of 2005, further increase beyond 2030 should only be supplied by carbon neutral energy sources;
- The GHG emissions of the country should be at least 40% below that of 1990 in 2030.
- Decrease the need for energy imports in general and decrease the share of electricity imports in the final electricity consumption from 32% (2013-2017 average) to below 20% by 2040;
- Increase the use of renewable energy sources to reach 21% in the gross final energy consumption by 2030 from 13,3% in 2017;
- 90% CO_2 emission free electricity generation by 2030 based on nuclear and solar technologies;
- Increase the share of the local RES production in the electricity consumption to 20% by 2030 and to close to 30% by 2040;
- The installed total solar capacity should exceed 6,0 GW by 2030 and approach 12,0 GW by 2040;
- Incentivize the use of smart meters in order to increase the flexibility of the grid - install ca. 1 million smart meters;
- Enhance the utilization of the country's geothermal potential;
- The local lignite assets should be considered strategic reserves and current lignite capacity at Mátrai Erőmű should be converted to low-carbon technologies;
- The energy and climate goals shall be met by keeping the energy costs low.

The strategy estimates that the costs of reaching the 2030 climate and energy goals are in the range of 14.700 billion HUF (44.5 bn EUR current prices).

(b) Governmental Institutions

The key institutions and their role in policy making include the following entities.

The Ministry for Innovation and Technology is, among others, responsible for formulating and implementing the economic, energy, climate, and transport policies of Hungary. Within these capacities the ministry also prepares and implements the strategic and policy documents to comply with Hungary's climate policy obligations originating from the European Union membership.

Ministry of Finance is, among others, responsible for setting and implementing the fiscal policies of Hungary, along with the preparation and monitoring of the budgetary processes. The ministry is also responsible for the administration of the European Union funds. In those capacities the Ministry of Finance has strong influence over the establishment and realization of economic, energy, climate, and transport policies.

Hungarian Energy and Public Utility Regulatory Authority (HEA), is the regulatory body of the energy and public utility market, supervising the national economy sectors of strategic importance.

HEA, as an independent regulatory authority entrusted with provision making power was established under Act XXII of 2013 as the successor of the Hungarian Energy Office (HEO) that was set up under Act XLI of 1994 on Gas Supply. The Authority's responsibility covers licensing, supervision, price regulation, tariff-and fee preparatory tasks in the fields of electricity, natural gas, district heating as well as in water utility supply, besides pricing of public waste management services.

As the official statistical body, HEA also performs standard national energy-statistics related tasks and complies with the data reporting obligations to various national and international bodies and organizations. As part of the National Statistical Data Collection Program, HEA liaises with roughly 5700 data suppliers. In cooperation with partners, maintaining security of supply and protecting retail, public and industrial consumers are also among HEA's key activities.

Keeping consumer interests in mind, HEA continuously supervises the license holders' billing, contract management and customer service activities.

The Act LVII of 2015 on Energy Efficiency has entrusted HEA with numerous regulatory, supervisory, energy-statistics and related communication tasks. HEA - among others - defines the methodology for the assessment of expenditures and revenues related to the power plants' use of waste heat and that of cogeneration as well as the requirements for the preparation of cost-benefit analysis. In view of the above, HEA enhances the reduction of energy consumption costs and the conservation of environmental resources for future generations.

HEA maintains close international relations at European, regional, and bilateral levels, its experts participate in the activities of the highest forums and organizations. Legal basis includes: Act 22 of 2013 on the Hungarian Energy and Public Utility Regulatory Authority, Act 86 of 2007 on Electricity, Act 40 of 2008 on Natural Gas Supply, Act 18 of 2005 on District Heating, Act 209 of 2011 on Water Public Utility Service and Act 185 of 2012 on Waste management.

Hungarian Atomic Energy Authority (HAEA) as a government office, is responsible for the regulatory tasks in connection with the use of atomic energy exclusively for peaceful purposes, the safety of nuclear facilities and transport containers, as well as for the security of nuclear and other radioactive material and associated facilities.

One of the most important international expectations on the safe and secure use of atomic energy is that the supervisory authority shall be independent of the interests of producers, owners, service providers, as well as of the state organizations having role in the promotion of the use of atomic energy. In Hungary, several stipulations of the Atomic Act and its implementation decrees guarantee the enforcement of the international expectations on independence.

The Hungarian Atomic Energy Authority, during its regulatory oversight activity, conducts comprehensive, targeted, regular and occasional inspections, during which it verifies the compliance with the requirements set forth in relevant laws and in the nuclear safety code, the accomplishment of the measures ordered by the Authority, as well as the safety and security of the various use of atomic energy.

FGSZ Földgázszállító Ltd. On the basis of the certification included in the Resolution of the HEA, as of 7 February 2012 is the natural gas Transmission System Operator (TSO), operates in accordance with the Independent Transmission Operator (ITO) model and as such is the owner and operator of the Hungarian high-pressure natural gas pipeline system servicing gas distribution companies, power plants and large industrial consumers. FGSZ focuses on contributing to the regional-level connection of the high-pressure long-distance pipeline systems of the surrounding countries, thereby facilitating the improvement of the security of supply, the availability and diversification of sources and the market conditions of the region. FGSZ prepares and upon approval by HEA carries out the natural gas transmission network development strategy. FGSZ is a member of the European Network of Transmission System Operators for Gas - ENTSOG.

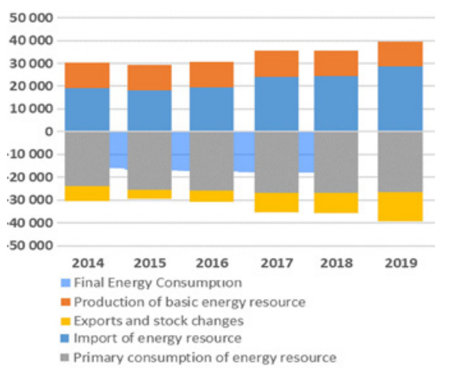
MAVIR Hungarian Independent Transmission Operator Company Ltd. On the basis of the certification included in the Resolution of the HEA as of 13 March 2012, MAVIR is operating in accordance with the ITO model, thereby MAVIR is the owner and operator of the transmission network within a vertically integrated electricity corporation. MAVIR, among others, is responsible for maintaining the capacity balance of the national electricity system and for balancing deviations of the balancing groups from planned targets, it provides for the reliable, efficient and secure operation of the Hungarian electricity system including required reserve capacities of generation and transmission, controls and augments the assets of the transmission system, performs all renewal, maintenance and development required for a proper and reliable supply, ensures an undisturbed operation and further extension of the electricity market and of the balancing group system supporting the market, and ensures access for system users on equal terms, synchronizes the operation of the Hungarian electricity system with the neighboring systems, coordinates professional international cooperation activities (among others as a member of the European Network of Transmission System Operators for Electricity - ENTSO-E), prepares the network development strategy and puts forward proposals for the development of the generation pool.

Energy Demand and Supply

Primary consumption of energy resources remained stable in Hungary in the last couple of years, with 26,9 Mtoe in 2017 and 26,4 Mtoe in 2019. Production of basic energy resource was slightly decreasing, with 11,3 Mtoe in 2017 and 10,7 Mtoe in 2019. In parallel, however, the import of energy resource has increase significantly from 24,1 Mtoe to 28,8 Mtoe.

The growth of the combined production and import compared to the stagnating demand resulted in increased energy export (mostly transit) (ca. 7,5 Mtoe in 2017 and 10,4 Mtoe in 2019[1]).

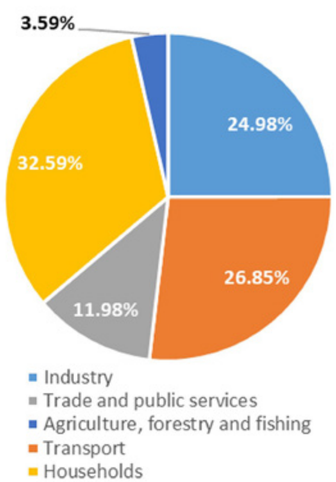
Figure 5.127 **Consolidated primary energy balance of Hungary (ktoe)**



Source: KSH/HCSO 3.8.1. Primary energy balance (1990-) [petajoule] and 5.7.1. Final energy consumption (1995-)* (ktoe); own elaboration

In 2017 the final energy consumption was 17.337 ktoe, which grew to 17.833 ktoe in 2018. The largest consumer sector was one for the households with 32,6%, followed by transport and industry sectors representing ca. one-fourth of the final energy consumption.

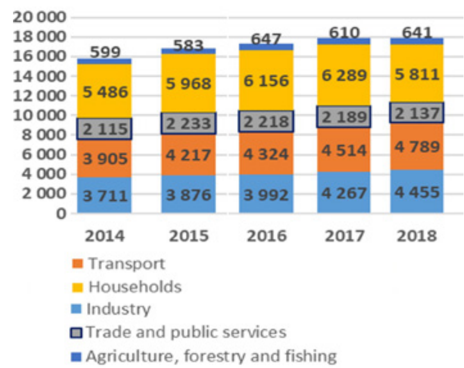
Figure 5.128 **Final Energy Consumption by sector 2018 (%)**



Source: KSH/HCSO 5.7.1. Final energy consumption (1995)* (ktoe); own elaboration

This sectoral breakdown stayed roughly the same in the previous years as well.

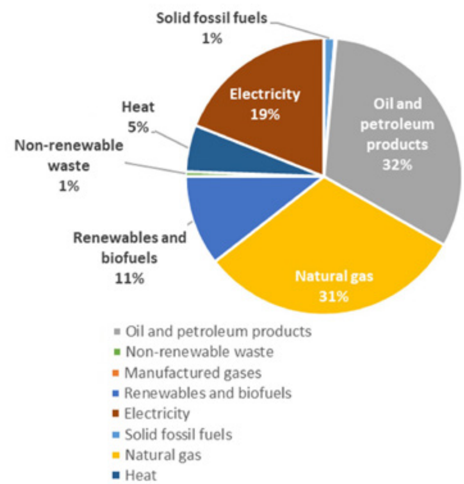
Figure 5.129 **Final Energy Consumption by Sector (ktoe)**



Source: KSH/HCSO 5.7.1. Final energy consumption (1995)* (ktoe); own elaboration

Natural gas and oil and petroleum products represent ca. one-third of the final energy consumption, with electricity representing ca 20%. The remaining ca. 20% is shared among renewables and biofuels, non-renewable waste, heat, and solid fossil fuels.

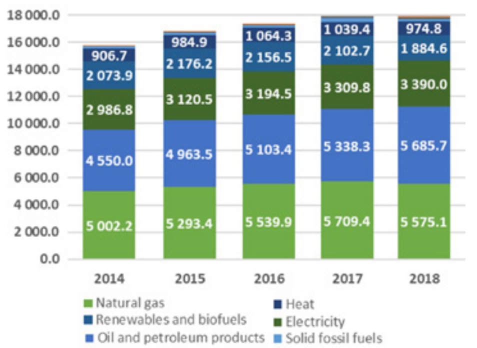
Figure 5.130 **Final Energy Consumption by Fuel 2018 (%)**



Source: HEA - National detailed Energy Balance - Eurostat format, 2018; own elaboration

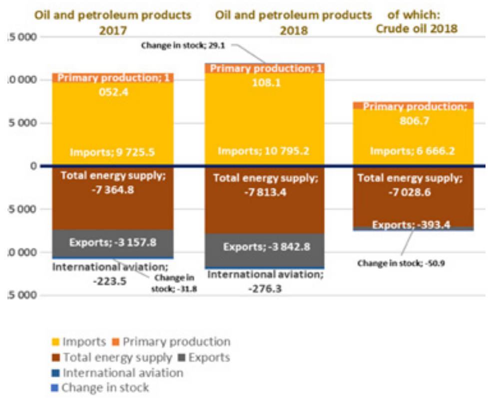
In the years following up to 2018 the share of oil and petroleum products has slightly increased, whereas the share of renewables and biofuels has decreased. The share of natural gas and electricity stayed practically the same.

Figure 5.131 **Final Energy Consumption Breakdown 2014-2018 (ktoe)**



Source: HEA - National detailed Energy Balance - Eurostat format, 2018; own elaboration

Figure 5.132 **Total Oil and Petroleum Products Balance 2017-2018 of which Crude Oil 2018 (ktoe)**



Source: HEA 7.4 National detailed Energy Balance - Eurostat format, 2018; own elaboration

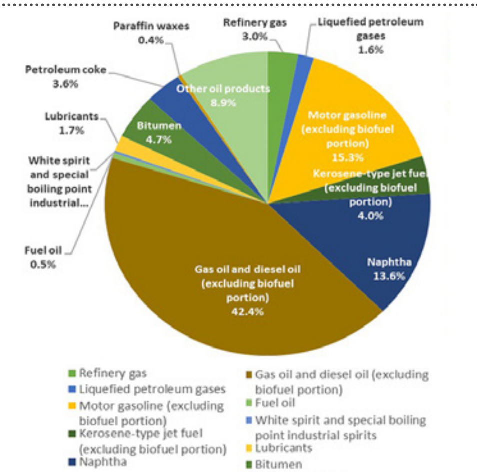
The Energy Market

(a) Oil and Petroleum Products

In 2018, the gross inland consumption of oil and petroleum products[2] was 8089,6 ktoe (7588,3 ktoe in 2017, a 6.6 % increase) or 162,457 barrels/day, out of which 7028,6 ktoe was crude oil. The import share of the gross inland consumption of oil and petroleum products was 133.44%[3] in 2018 (5.3 % higher than in 2017). The reason for the above 100% value is that most exported products are produced from import feedstock. The primary production of oil and oil products' share in the gross inland consumption was 13,7% in 2018 (13,9% in 2017). The share of the primary production of crude oil in the gross inland consumption of crude was 11,5% in 2018. According to HEA, the annual production of crude oil in Hungary in 2018 was 0.000808 thousand million tons (808 kt/y) or 16.226 barrels/day. This means that indigenous production covers approximately 13.6% of total oil consumption, whereas the production of other primary oil in 2018 was 0,000295 thousand million tons per year (295 kt/y), meaning that the total supply of crude and other primary oil was 0,001103 thousand million tons per year (1.103 kt/y) or 22.150 barrels/per day.

Refineries and petrochemical industry's transformation input was 8.426,7 ktoe in 2018 (6,9% increase on 2017), whereas transformation output thereof was 8.364,7 ktoe (6,9% increase on 2017). The product with the highest share in refinery output was gas oil and diesel oil with 42,4%, followed by motor gasoline 15,3%; naphtha had the third largest share with 13,6%.

Figure 5.133 **Refinery output 2018 (%)**



Source: HEA 7.4 National detailed Energy Balance - Eurostat format, 2018; own elaboration

2 Total Energy Supply + International Aviation

3 It is above 100%, as most product export is transformed from import feedstock. Gross Inland Consumption = Primary Production + Imports -Exports +/- Stock Change (Eurostat format Energy Balance)

According to the Mining and Geological Survey of Hungary (MBFSZ/MGSH), Registry on Mineral Raw Materials and Geothermal Resources, the contingent reserves of crude oil (1) oil on 1 January 2019, were 5.103 thousand million bbl (811,83 Mm3), thereof 1.725 thousand million bbl conventional and 3.378 thousand million bbl unconventional; whereas the proven reserves (2) were 0,517 thousand million bbl (82,12 Mm3), thereof 0,148 thousand million bbl conventional and 0.368 thousand million bbl unconventional. According to their records, there were 325 crude oil and natural gas mining plots in the country on 1 January 2019.

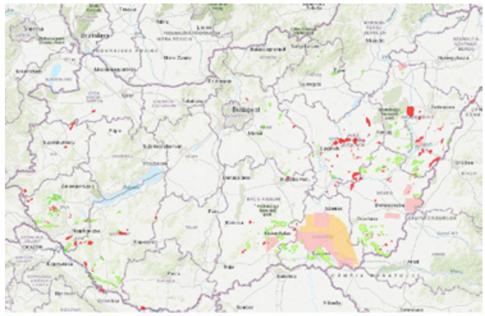
Within the framework of the mining concession system launched by the Government in 2013, the Ministry of Innovation and Technology issues public invitations to tender the prospecting, exploration, and production of hydrocarbons in the designated concession areas (blocks). Participation in the tendering process is open to any Hungarian or foreign natural person or entities with the capacity to act, and any transparent organization as defined by Act CXCVI of 2011 on National Assets. Additional legislation concerning prospection, exploration and production of hydrocarbons are the following: Act XVI of 1991 on concessions ('the Concessions Act') and Act XLVIII of 1993 on mining ('the Mining Act'). The following maps provide an overview of oil and oil-associated gas fields.

Map 5.38 **Hydrocarbon mining and exploration plots in Hungary**

Operative hydrocarbon mining plots
Operative hydrocarbon exploration plots

Source:Mining and Geological Survey of Hungary - Cadaster of Mineral Raw Materials - Online Map

Map 5.39 **Known conventional and unconventional hydrocarbon fields in Hungary**



Conventional crude oil and associated gases
Conventional crude oil
Conventional natural gas
Unconventional natural gas and condensate
Unconventional natural gas

Source: Mining and Geological Survey of Hungary - Cadaster of Mineral Raw Materials - Online Map

MOL Hungary Plc, member of the MOL Group is the owner and operator of the Danube Refinery in Százhalombatta, with a capacity of 165.000 bpd of crude oil and a Nelson Complexity Index (NCI) of 10,6. It is one of the largest refineries in CEE. "The Danube Refinery is operated as a hub in co-ordination with the MOL-owned 124 kb/d refinery (NCI 11,5) in Bratislava (Slovak Republic) and a significant amount of intermediate products are exchanged between the two." (IEA)

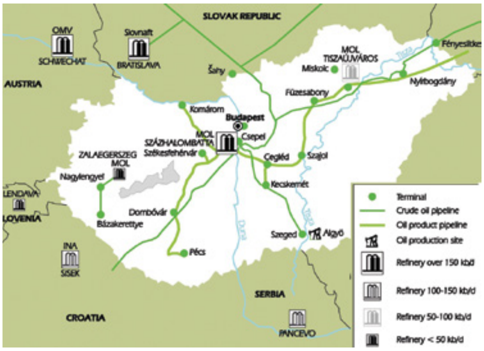
There are also two smaller MOL Plc. refineries in Tiszaújvaros (60 kb/d) and Zalaegerszeg (10 kb/d) which do not process crude oil at present. "There is no oil port in Hungary, but there is the option to export and import refined products by barge from Komárom and Százhalombatta. A large proportion of product exports from the MOL refineries are transported by barge on the Danube River." (IEA)

Crude oil is supplied to Hungary through pipelines. The Southern Friendship (Druzhba) pipeline system, originating in Russia and transiting Belarus and Ukraine, is Hungary's main crude oil supply channel. The section of the older Druzhba I pipeline (built in 1961) between Százhalombatta and Sahy has recently been fully renovated and increased its capacity from 70 kb/d (3,5 Mt/year) to 120 kb/day (6.0 Mt/ear). It enables supplies to Hungary from its northern border with the Slovak

Republic. The Druzhba II (built in 1971) has a capacity of 160 kb/d (7,9 Mt/year) and supplies Hungary from its eastern border with Ukraine. The pipeline terminates at the Duna refinery at Százhalombatta (via the Tisza refinery). Domestic oil production is transported via an internal pipeline between Algyő, where oil is produced, and the Százhalombatta refinery." (IEA)

The Adria oil pipeline section between Sisek and Százhalombatta has also undergone recent renovation and increased its capacity from 200 kb/d (10 Mt/yr) to 280 kb/d (14 Mt/yr), roughly equal to the total processing capacity of the Bratislava and Duna refineries combined. This pipeline links the Duna refinery to the Croatian port of Omišalj. This pipeline was originally intended for the delivery of crude oil imports from the Middle East or Africa to Hungary but was mainly used for transporting Russian crude oil in the opposite direction, transiting to the Sisek refinery in Croatia. In recent years, its use for transporting cargoes from Omišalj (the pipeline's original purpose) has increased. Hungary is also linked to the Eastern oil product pipeline that transports product from Russia's refining centers via Ukraine. This enables MOL to purchase gasoil feedstock from Russia for further processing. (IEA) According to the IEA total storage capacity in Hungary in 2015 was 3,1 mcm (19,5 mb): 1,1 mcm of this capacity is for crude oil storage and 1,9 mcm for product storage. There has been no substantial change since then.

Map 5.40 **Hungary's Oil Facilities**



Source: IEA - Energy Policies of IEA Countries - Hungary 2017 Review

The Hungarian wholesale and retail oil markets are fully liberalized. The largest market player in Hungary is MOL, which is an integrated international oil and gas group. The group has also extensive upstream and downstream interests in other countries. It is active in all downstream activities, including refining, pipelines, and retail. The wholesale market is dominated by MOL and OMV, the main regional refiners.

At the end of 2017 there were 2.077 filling stations in Hungary. Based on the website of the companies, there are currently 472 MOL, 194 OMV, ca 170 Shell, ca 75 Normbenz (under Lukoil brand) (2020 May) and ca. 850 are independently owned. "There have been a number of mergers and acquisitions in the retail market over [the recent years]. For example, in 2014, Normbenz acquired the Lukoil stations in Hungary (and in Slovak Republic) but kept the Lukoil brand. In 2016, MOL acquired all ENI stations in Hungary, which officially became MOL property from 1 August 2016." (IEA)

(b) Natural Gas

Infrastructure

TSO FGSZ operates 5.874 km of gas transmission network with a diameter of 80-1400 mm. Eight compressor stations (Beregdaróc, Nemesbikk, Hajdúszoboszló, Városföld, Csanádpalota, Szada, Báta, Mosonmagyaróvár) provide the pressure for the operation of the system at 40-75 bar. The Natural Gas is delivered at ca 400 delivery stations to the Distribution System Operators (DSO) and to industrial consumers. There are also 17 main junctions (hubs) of the long-distance pipelines. FGSZ also operates the gas interconnectors to all neighboring countries, except Slovenia, which is in planning phase. The system is operated via six territorial control centers and a national headquarter: the dispatching center in Siófok. The task is carried out by the National Telemechanical System (NTS), whereas the data transmission belongs to the Supervisory Control and Data Acquisition (SCADA) function.

Map 5.41 **Hungary's Gas Transmission Network** [4]

Source: HEA-FGSZ - Data of the Hungarian Natural Gas System 2018

Currently there is a network of ca. 84.100 km of distribution pipeline Network operated by ten licensed DSOs, with ca. 3,26 million distribution pipeline gas meters. There are ca. 3,47 million consumers connected to the natural gas system, out of which 3,26 million are household consumers.

Table 5.122 **Technical Data of Natural Gas Transmission and Distribution Pipelines as well as Storage Facilities**

	SZÁLLÍTÓVEZETÉKI MŰSZAKI ADATOK TECHNICAL DATA OF TRANSMISSION PIPELINES		ELOSZTÓVEZETÉKI MŰSZAKI ADATOK TECHNICAL DATA OF DISTRIBUTION PIPELINES		TÁROLÓI MŰSZAKI ADATOK TECHNICAL DATA OF STORAGE FACILITIES		
	SZÁLLÍTÓVEZETÉK HOSSZA [KM] LENGTH OF NATURAL GAS TRANSMISSION PIPELINE [KM]	ÁTADÓÁLLOMÁSOK SZÁMA [DB][1] NUMBER OF DELIVERY STATIONS [PCS][1]	ELOSZTÓVEZETÉK HOSSZA DECEMBER 31-ÉN [KM] LENGTH OF DISTRIBUTION PIPELINE AS OF 31 DECEMBER [KM]	ELOSZTÓVEZETÉKI GÁZMÉRŐK SZÁMA DECEMBER 31-ÉN [DB] NUMBER OF DISTRIBUTION PIPELINE GAS METERS AS OF 31 DECEMBER [PCS]	TÁROLÓI MOBIL KAPACITÁS [Mm³] CAPACITY OF STORAGE FACILITY [Mm³]	KITÁROLÁSI KAPACITÁS [Mm³/NAP] WITHDRAWAL CAPACITY [Mm³/DAY]	BETÁROLÁSI KAPACITÁS [Mm³/NAP] INJECTION CAPACITY [Mm³/DAY]
2015	5 873,4	399	83 618,9	3 233 470	6 330,00	78,60	44,65
2016	5 873,4	400	83 732,1	3 236 014	6 330,00	78,60	44,65
2017	5 873,0	400	83 872,7	3 238 675	6 330,00	78,60	44,65
2018	5 873,4	400	84 079,3	3 256 042	6 330,00	78,00	45,30

Source: HEA-FGSZ - Data of the Hungarian Natural Gas System 2018)

[4] On October 4, 2019 at 6 a.m., FGSZ took over the operation of the 92 km long natural gas transmission pipeline from MGT Ltd. connecting Hungary to Slovakia thus, the entire, nearly 6000 km long high-pressure natural gas transmission pipeline system of Hungary is now operated by FGSZ. - FGSZ Press Release - 04 October 2019.

There are 5 underground gas storage facilities in Hungary, with a combined working gas volume of 6,33 bcm; withdrawal capacity of 78 mcm/d; injection capacity of 45,3 mcm/d.

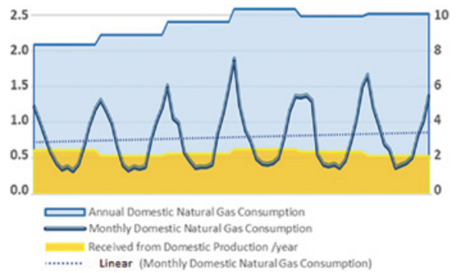
Map 5.42 **Gas storage facilities in Hungary**

Source: GIE Storage Map 2018

Gas Consumption

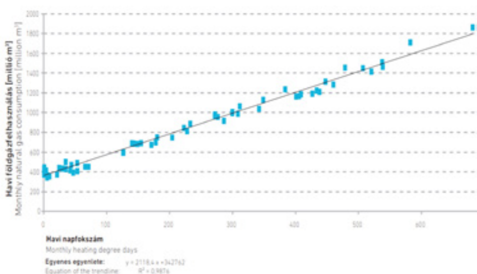
Domestic gas consumption[5] in 2019 was 10,08 bcm. The average domestic gas consumption in the 2017-2019 period amounted to 10,12 bcm/y, with a slightly increasing trend. The average y-o-y increase in annual domestic gas consumption was 3,94% in the 2014-2019 period. However, it must be noted that gas consumption is strongly influenced by the number of heating days occurring each year. The domestic production[6] in 2019 amounted to 2,13 bcm vs 2,46 in 2014. The trend of production was slightly decreasing -2,4% in the period of 2014-2019. The difference between domestic consumption and production corresponds to imports. The share of imports in the domestic consumption reached 78,8% in 2019 vs 70,5% in 2014. The share of natural gas imports in primary energy import reached 44,29% in 2018 vs. 32,4% in 2015. The natural gas intensity of the economy however has decreased significantly to ca. 60% of the value in year 2000.

Figure 5.134 **Domestic Natural Gas Consumption (bcm/month & year, 15C)**



Source: HEA-FGSZ - Data of the Hungarian Natural Gas System 2018; own elaboration

Figure 5.135 **Correlation between monthly natural gas consumption and monthly heating degree days**



Source: HEA-FGSZ - Data of the Hungarian Natural Gas System 2018

The Gas Market

"The imported and domestically produced natural gas is sold to domestic users by traders and universal service providers. Natural gas distribution systems are operated by 10 regional distributor companies. Most of the regional distribution activity is carried out by five large companies which are geographically divided. Since market opening in 2004 the retail market has been characterized by a dual structure. In the free market segment, the prices are formed by the market. Consumers eligible for universal service can get natural gas on a regulated (maximized) price.

[5] Does not include the production directly delivered to consumers, associated gas from thermal water production, domestic CH4 production and the auto consumption of producers.

[6] Certified quantity delivered to the natural gas grid from the producers. Does not include production delivered to island networks, directly to consumers or auto consumption of the producers.

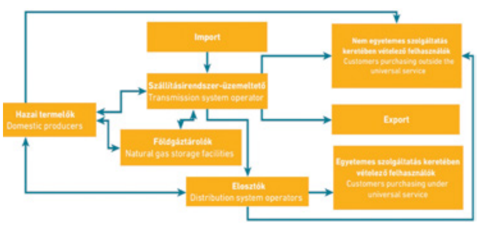
The customers eligible for universal service are the household consumers, other customers with purchased capacity below 20 m3/hour, and the local governments up to the capacity to supply consumers living in rented apartments provided by local governments.

Non-eligible customers either purchase natural gas from the competitive market as earlier, or entered the free market upon termination of their eligibility to universal service (customers with medium and low consumption and district heating generators)." (HEA)

In 2018, 3,7 bcm of natural gas has was sold within the universal service for eligible customers (3,35 bcm household customers and 0,36 bcm other) and 4,8 bcm was sold to non-eligible customers in the wholesale market (99,9% non-household customers).

The universal supplier is the NKM Energia Zrt, a subsidiary of the NKM Nemzeti Közművek Zrt, a subsidiary of the state owned, MVM Group. The HHI competition index of the sales to household end users was 9984 in 2018. In 2018, there were 43 companies active in the wholesale market and the HHI competition index of the sales in the wholesale market was 1987 in 2018. The model of the domestic natural gas sector is presented in Figure 5.136.

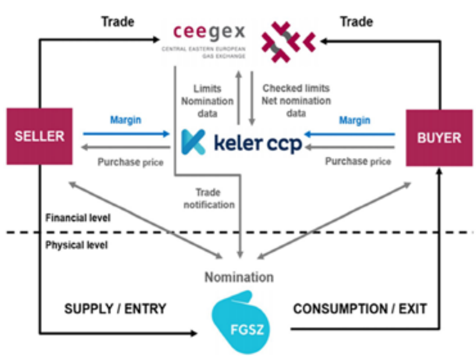
Figure 5.136 **Current operational model of Hungary's domestic Natural Gas sector**



Source: Source: HEA-FGSZ - Data of the Hungarian Natural Gas System 2018

The Central Eastern European Gas Exchange CEEGEX Ltd[7] is the organized gas market providing physical within-day and day-ahead market trading on the Hungarian Virtual Point (MGP) and on locational points. Total spot volume reached 34.338 GWh in 2019, a four-fold increase compared to 8405 GWh volume of 2018. There are 37 exchange members and two market makers. In 2019, the premium over the CEGH price was between 0,2 – 2,5 EUR/MWh and 0,2 - 4 EUR/MWh over TTF.

Figure 5.137 **Nomination/position netting Limit check**



Source: HUPX Group Brochure 2020 - Energy Business Motion

Gas future contracts[8] are available on the Hungarian Derivative Energy Exchange - HUDEX Energy Exchange Ltd., member of the HUPX Group., through Currently, there are two market makers, RWE and MFGK on this market.

(c) Solid Fuels

Balance

In 2018, the gross inland consumption of solid fossil fuels was 2.120,3 ktoe (2.234,7 ktoe in 2017, a 5,1% decrease), out of which 1.235,7 ktoe was lignite. In 2018, the import share of the gross inland consumption of solid fossil fuels was 58,63% (2,3% higher than in 2017).

[7] Part of the HUPX Group, a subsidiary of the electricity TSO MAVIR, a subsidiary of the state owned MVM Group
[8] Balance of Month, Seasonal, Yearly contracts

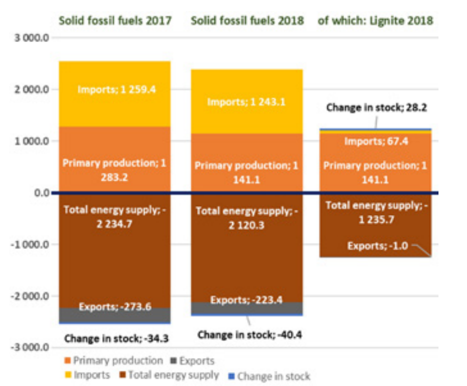
The primary production of solid fossil fuels compared to the gross inland consumption was 53,8% in 2018 (3,6% lower than in 2017). 100% of primary production was lignite.

Lignite represented 58,3% (1.235,7 ktoe) of the gross inland consumption in 2018, 92,.3% of which was from primary production. 92,1% of the lignite was used in electricity and heat generation, the remaining was used by households and industry.

In 2018, coking coal represented 80,8% of the solid fossil fuel imports. After correction with stock changes and statistical differences, 100% of the imported coking coal was used in coke ovens (977,2 ktoe) to produce coke (668,7 ktoe) for steel production.

As far as electricity production is concerned, Hungary is self-sufficient in terms of indigenous solid fuel resources (lignite) whereas the import supplies are exclusively destined for coking coal which is used in steel production (ISD Dunaferr Zrt.). In 2018, 80,9% of the solid fossil fuel exports was for coke oven coke (re-export) and 18,7% was coal tar. There were also marginal lignite exports as well.

Figure 5.138 **Solid Fossil Fuels Balance 2017-2018 and of Lignite 2018 (ktoe)**

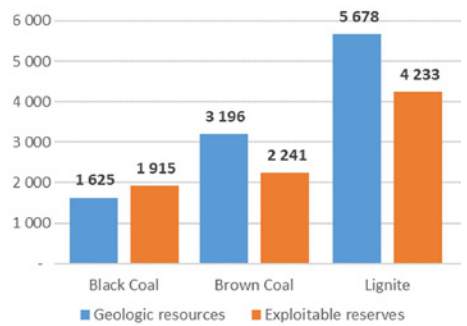


Source: HEA - 7.4 National detailed Energy Balance - Eurostat format, 2018; own elaboration

Resources

According to the Mining and Geological Survey of Hungary (MBFSZ/MGSH) and the Registry on Mineral Raw Materials and Geothermal Resources, the geological resources of lignite on 1 January 2019, were 5,678 million tons (mt), whereas the exploitable reserves were 4,233 mt. The geological resources and exploitable reserves of black[10] - and brown coal are highlighted in Figure 5.139.

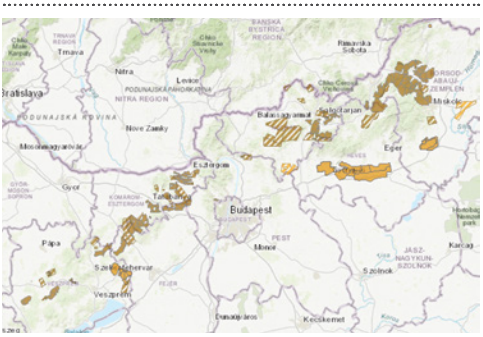
Figure 5.139 **Geological Resources Inventory of Solid Fuels in Hungary in 2019 (mt)**



Source: Mining and Geological Survey of Hungary - Inventory of Mineral Resources as of 1 January 2019; own elaboration

The following map (Map 5.43) provides an overview of the current and prospective black coal, brown coal, and lignite deposits.

Map 5.43 **Current and prospective black coal, brown coal, and lignite deposits in Hungary**



Source: Mining and Geological Survey of Hungary - Cadaster of Mineral Raw Materials - Online Map

9 Import share of gross inland consumption + primary production of solid fossil fuels combined are higher than 100% due to export.

10 Attenuation is higher than loss (Geologic reserve + attenuation - loss - pillar = Exploitable reserve) /quantity of exploitable coal + interim waste rock may exceed the registered geologic reserve!

The following map (Map 5.44) provides an overview of operative, suspended, and closed coal and lignite mining plots and ongoing prospecting activities.

Map 5.44 **Operative, suspended, and closed coal and lignite mining plots and ongoing prospecting activities in Hungary**

Source: Mining and Geological Survey of Hungary - Cadaster of Mineral Raw Materials - Online Map

Lignite is mined in Visonta and Bükkábrány through strip mining. The mines supply the Mátra power plant, the local population and also cover domestic demand in industry.

Strategy and Investments

With regard to future divestments, the operating permit of the last lignite block at the Mátra PPT expires in 2029, while other permits expire by 2025. The power plant is the second largest PPT in Hungary (896,3 MW installed capacity and ca. 17% of produced electricity), thus plays an important supply security role, therefore the National Energy Strategy 2030 document foresees the replacement of its lignite power generation capacities with low(er) GHG intensity technologies. According to NES a new CCGT plant (potentially 500 MW) is foreseen, along with additional solar capacities and the potential utilization of municipal-waste for power generation on this site. NES foresees keeping the more modern lignite plants as strategic reserve, due to the existing, significant lignite deposits, while completely shutting down the others. The Mátra PPT currently emits ca 50% of the CO_2 emissions in the power sector which constitutes 14% of total emissions.

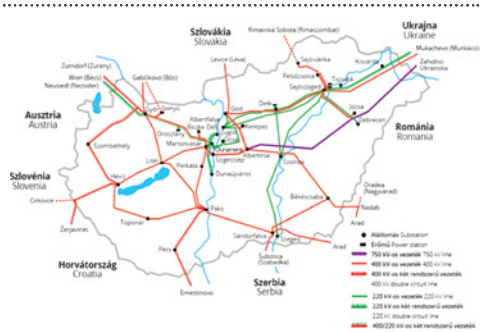
Apart from the Visonta strip mine site, there are no more operative prospecting permits, so no investments are foreseen in this sector. Additionally, although public discussion is taking place for years, the current energy strategy document does not foresee the application of clean coal technologies.

(d) Electricity

Infrastructure

In 2018, the TSO MAVIR operated 4861 km of high-voltage overhead lines and cables (with a route length of 3813 km) in the voltage range of 132 kV to 750kV. The TSO also operated 33 substations throughout the country, along with the interconnectors with all neighboring countries, except for Slovenia where the project is in permitting phase in Slovenia according to ELES, the Slovenian TSO; according to MAVIR the project does not require significant CAPEX in Hungary. MAVIR also operates the market of ancillary services and the balance group system as well as allocates the cross-border capacities.

Map 5.45 **Hungarian Electricity Transmission Network on 31 December 2018**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

The route length of the distribution network operated by the six licensed DSOs was 161.578 km in 2018, out of which 6.377 km was high-voltage, 67.202 medium-voltage and 87.999 km low-voltage overhead lines and cables.

[11] Dr. László Palkovics, Minister of Innovation and Technology - https://www.kormany.hu/hu/innovacios-es-technologiai-miniszterium/hirek/korszerusitve-mukodhet-tovabb-a-matrai-eromu

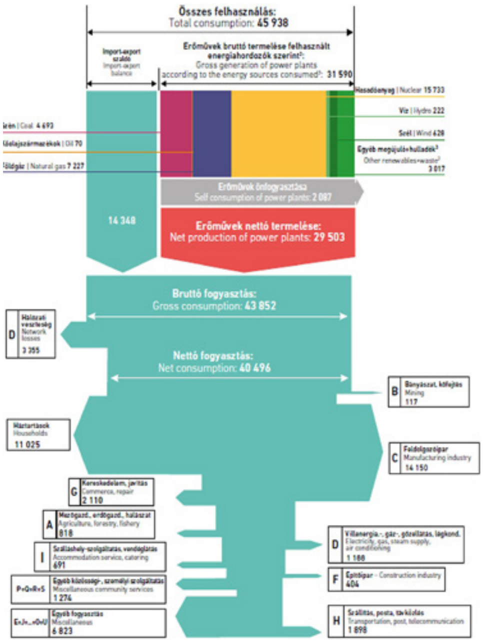
Balance

The domestic electricity consumption increased from 40,12 TWh in 2017 to 41,2 TWh in 2019. The average annual growth of domestic consumption from 2014 until 2019 was 2,2%. The exports showed high fluctuations in the previous 3 years and ranged between 4,27 TWh per year in 2018 and 7,27 TWh in 2019, whereas the import share of the total consumption[12] remained high at around 37%. The import share in the electricity consumption has historically been high, although fluctuated between almost 40% and 8,1% since 1990. With the better access to cheaper electricity prices in neighboring markets and also thanks to the day-ahead market coupling of the CZ-SK-HU markets since September 2012 and the RO market in November 2014, the import share increased and remained high.

Also, the different installed the capacity mixes and the lower Marginal Cost of these countries compared to Hungary can explain the high import share.

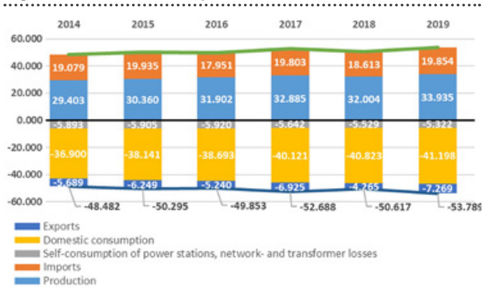
An additional reason for the increased import share is the fact that domestic production has decreased by ca. 10% since 2010 -37,371 TWh in 2010 vs 33,936 TWh in 2019- whereas the total consumption has increased by 13,8% (export by almost 55% and domestic consumption by 14%).

Figure 5.140 **Hungary's Electricity Generation and Consumption, 2018 (GWh)**



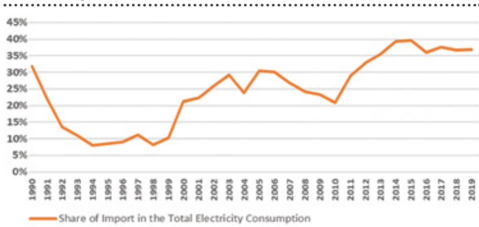
Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018 Note: Certain data items are different based on HCSO and HEA-MAVIR data supply

Figure 5.141 **Electricity Balance (TWh)**



Source: KSH/HCSO 3.8.2. Electricity balance (1990-); own elaboration

Figure 5.142 **Share of Import in the Total Electricity Consumption (%)**

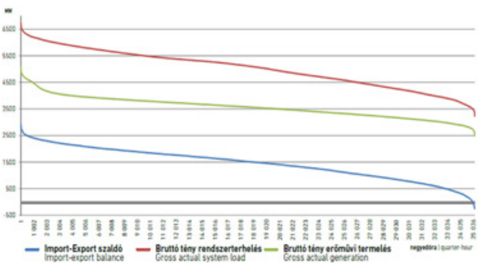


Source: KSH/HCSO 3.8.2. Electricity balance (1990-); own elaboration

[12] Domestic Consumption + Export

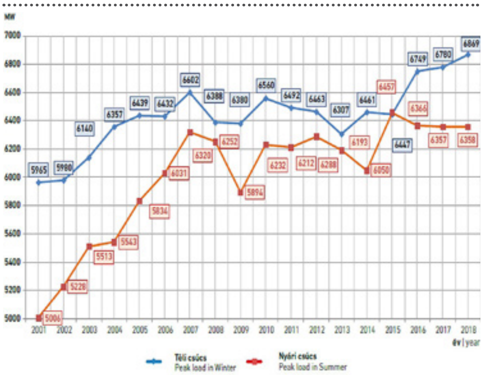
Maximum gross peak system load in 2018 was 6.869 MW on 19 December (1,29% increase from previous year and 6,3% increase since 2014). Minimum gross peak load was 4.502 MW on 20 May. Maximum gross domestic generation was 5.196 MW on 20 December. Daily summer peak load occurred on 21 June with 6.358 MW (6.357 MW in previous year on 28 June 2017).

Figure 5.143 **Annual Duration curve of the Hungarian Electricity System**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

Figure 5.144 **Winter and Summer peak loads, 2001-2018**

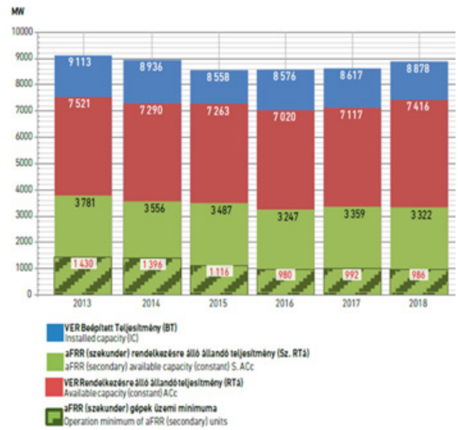


Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

Power Plants and Generation

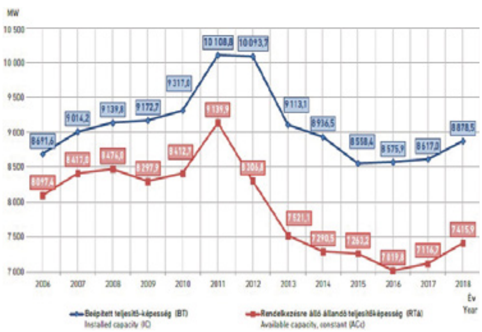
Hungary's total installed capacity at the end of 2018 was 8.878 MW which represents a 3% increase compared to the end of 2017. Out of this installed capacity, 6.923 MW were large power plants, whereas 1.955,5 MW were small power plants.

Figure 5.145 **Installed and available capacities in the Hungarian Electricity System**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

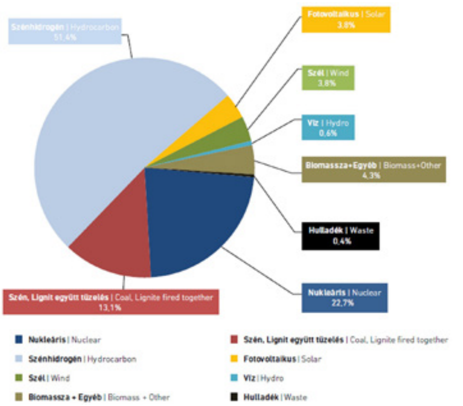
Figure 5.146 **Development of the capacity of the Electricity System on 31 December**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

The highest share of the installed capacity, based on the primary energy sources was hydrocarbon-based power plants representing 51,4% of the installed capacity, followed by nuclear 22,7% and coal-lignite with 13,1%. Renewables (solar, wind, hydro, biomass + other) represented ca. 12,4% of the installed capacities. Although the data was not available at the close of editing, thanks to significant increase in solar installed capacities, the share of renewables is set to increase by 2020 and beyond.

Figure 5.147 **Primary Energy Sources of Domestic Power Plants on 31 December 2018**

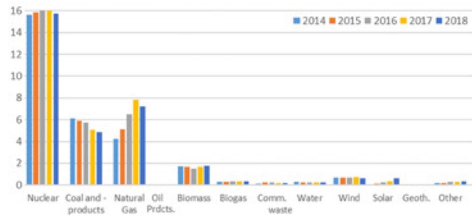


Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

Figure 5.147 shows the power plants which are subject to license. There was also 333,7 MW of installed capacity corresponding to small-scale household power plants at the end of 2018, a significant, 38,5% jump compared to 2017 and more than 100 times than in 2011 (3,17 MW). According to HEA, the installed capacity of small-scale household power plants reached 462,36 MW by the end of 2019, 99,6% of which is solar.

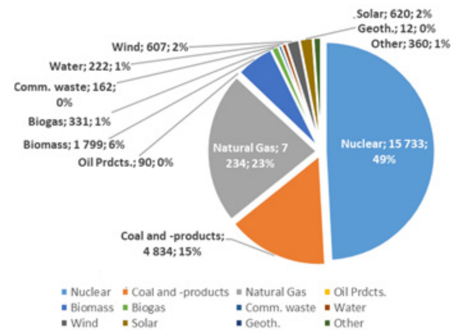
Nuclear power dominates the power generation with ca. 50%. Natural gas represents 23%, whereas coal and coal products (lignite) based power plants produce 15% of the electricity generated in Hungary. If biogas and biomass-based generation are considered carbon neutral, then 60,38% of the power generation was carbon free in 2018[13]. A slight decrease from the 63,5% of 2014.

Figure 5.148 **Gross Electricity Production by Source 2014-2018 (TWh)**



Source: HEA - 4.2 Gross Annual Power Generation 2014-2018; own elaboration

Figure 5.149 **Gross Electricity Production by Source 2018 (GWh,%)**



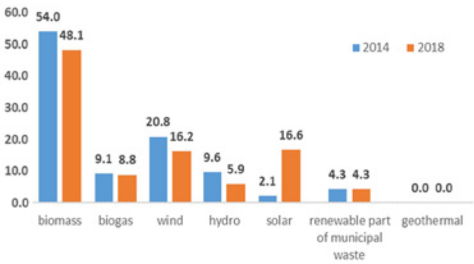
Source: HEA - 4.2 Gross Annual Power Generation 2014-2018; own elaboration

The share of renewable resources and waste in electricity consumption increased slightly between 2014 - 7,4% and 2018 - 8,1%.

Biomass dominates the renewable power generation in Hungary corresponding to almost half of the RES generation in 2018. However, the share of solar generation was already increased significantly, reaching 16,6% of RES generation in 2018. This increase is expected to continue due to the newly installed solar capacities (ca. 330MW end of 2017 vs. ca. 1.400 MW end of 2019 including household and commercial plants) which is expected to increase the share of RES generation as well.

[13] Carbon-free at the moment of generation, but not on a life-cycle basis.

Figure 5.150 **Share of renewable resources and waste in electricity consumption (2014 vs 2018) [%]**



Source: HEA - 4.2 Gross Annual Power Generation 2014-2018; own elaboration

With regard to investments, the National Energy and Climate Plan foresees a large increase of installed solar capacities to 6.500 MW by 2030 and potentially to 10.000 MW by 2040. By the end of 2016, HEA had issued permits for ca. 2.000 MW of small solar (not household) PPTs in the so call Compulsory Feed In regime (Kötelező Átvétel - KÁT). Estimates vary between 60-90% on how many of these permits will result in actual installations. Hence, the validity of the permits was prolonged until the end of 2021.

During the first, auction-based support scheme tender, known as the Renewable Energy Support System (Megújuló Támogatási Rendszer - METÁR), HEA awarded a total of 157,54 MW capacities. The winners obtained a weighted average price of 24,81 HUF/kWh in the small solar PPT category and 21,69 HUF/kWh in the large solar PPT category.

The other pillar of the policy for a 90% target of CO_2 emission free electricity generation by 2030 is the retention of the existing nuclear generation capacities, currently 2012,8 MW (4 reactor blocks) which were planned to be shut down between 2032 and 2037 despite their extended lifetime. On 14 January 2014, the Hungarian Government signed an inter-governmental agreement with the Russian Federation[14] for the construction of two new VVER nuclear blocks with at least 1000MW capacity each.

Additionally, on 28 March 2014 the Hungarian Government and the Russian Federation signed an inter-governmental loan agreement to finance the construction of the power plant with a maximum EUR 10 bn credit. The EPC Contract has been signed between MVM Paks 2 Ltd[15] and JSC NIAEP [16]. Currently there is no official commissioning date for the project but expert opinions name the early 2030s as the possible startup date of operation.

Market

"The power plants sell the generated electricity to traders and universal service providers, who resell it on the wholesale market or supply the customers directly. Electricity flows from the generators to customers through transmission and distribution networks. The transmission and distribution activities are to be performed by unbundled companies in line with the provisions of EU 3rd Energy Package.. The current structure of the Hungarian electricity market essentially took shape around 1995, when most, large power plants, the public utility suppliers and the distribution networks were privatized. Presently, domestic power plants sell most of their power generation through agreements concluded with the Hungarian Electricity Ltd. (MVM): through framework contracts to the universal service providers and through either bilateral contracts or public capacity auctions to the traders. A significant part of primary purchases of traders goes through a secondary trade within the trading sector before reaching final customers or export markets." (HEA)

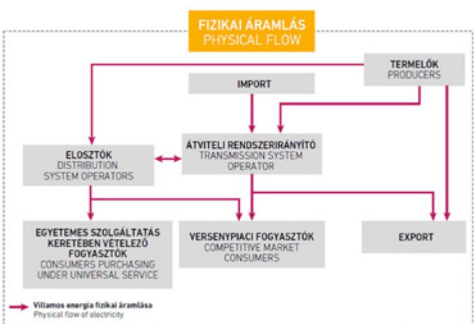
In 2018, 11.597 TWh electricity has been sold within the universal service for eligible customers (10,97 TWh household customers and 0,627 TWh other) and 26.925 TWh was sold on the free market (99,8% non-household customers). There have been in total 5.324.618 customers in the universal service (thereof 5.108.411 household customers) and 259.533 customers on the free market (thereof 15.401 household customers).

[14] Agreement between the Government of Hungary and the Government of the Russian Federation for cooperation in the peaceful uses of nuclear energy, signed at Moscow, 14th January 2014.
[15] MVM Paks II. Nuclear Power Plant Development Private Company Limited by Shares
[16] Joint-Stock Company Nizhny Novgorod Engineering Company Atomenergoproekt

The universal suppliers of the Hungarian electricity market are E.ON Energiakereskedelmi Kft., (a subsidiary of E.On Group) ELMŰ-ÉMÁSZ Energiaszolgáltató Zrt. (a subsidiary of Innogy) and NKM Áramszolgáltató Zrt. (a subsidiary of the NKM Nemzeti Közművek Zrt, a subsidiary of the state owned MVM Group). These universal suppliers (and DSOs) operate at different, non-overlapping geographic areas of the country. In 2018, there were 150 licensed traders in Hungary, out of which 99 were active. The HHI competition index of the sales on the free market was 1357 in 2018.

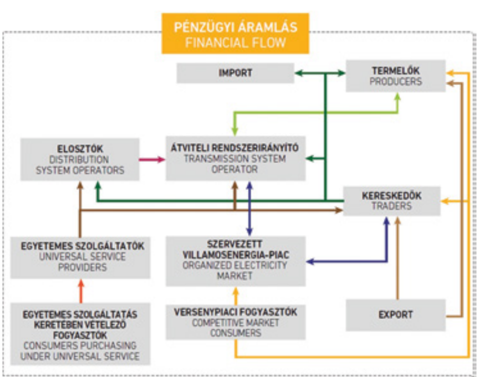
The model of the Hungarian electricity market is presented in Figures 5.151, 5.152, 5.153.

Figure 5.151 **Operating Model of the Hungarian Electricity Market**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018)

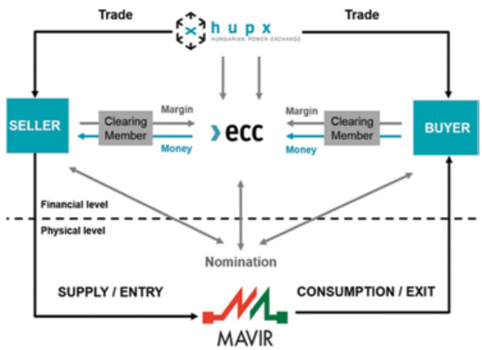
Figure 5.152 **Financial Flow of the Hungarian Electricity Market**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018)

The Hungarian Power Exchange HUPX Ltd is the organized electricity market providing trading with day-ahead and intraday contracts. Total traded volume on the day-ahead market reached 22.243 TWh in 2019, an 11,7% increase compared to the 19,98 TWh traded in 2018. The total traded volume on the intraday market reached 0,156 TWh, which is nearly three times higher compared to the 0,055TWh traded in 2018. Currently, there are 59 day-ahead market members and 36 intraday market members.

Figure 5.153 **Model of the Hungarian Electricity Market**



Source: HUPX Group Brochure 2020 - Energy Business Motion

The Hungarian Derivative Energy Exchange - HUDEX Energy Exchange Ltd., is a member of the HUPX Group and electricity futures contracts are available, with a market maker.

MAVIR prepares each year the National Ten-Year Network Development Plan (NDP), where it summarizes the necessary grid developments under different future load scenarios until 2034 (2019 edition) in the following categories: development of the transmission system; connection of power plants; development of the distribution system.

There are also three Projects of Common Interest (PCI) selected in line with the TEN-E Regulation in Hungary, which are the 3.17 Interconnection Hungary - Slovakia between Sajóivánka (HU) and Rimavská Sobota (SK); the 3.16.1 Interconnection Hungary - Slovakia between Gabcikovo (SK) and Gönyű (HU) and Velký Dur (SK) and the 10.7 Danube InGrid project (Hungary, Slovakia) -enhancing cross-border coordination of electricity network management, with focus on smart data collection and exchange.

(e) Renewables

"The trade of electricity generated from renewable resources and waste falls in a special trading category. This kind of electricity has to be purchased from generators by the transmission system operator (MAVIR Zrt.) under the feed-in tariff (FiT) scheme (at a price specified in the respective legislation and in volumes and during a period defined by HEA). MAVIR Zrt. sells the electricity purchased in the framework of FiT and the corresponding balancing energy to the traders, and another part in the organized electricity market." (HEA) Most of the currently installed renewable generation capacity is supported under a Feed-in Tariff (FiT) regime (Kötelező Átvétel - KÁT).

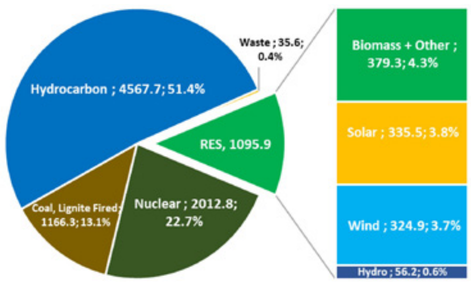
This system supports power plants with an installed capacity of 50-500 kW. "The FiT system was replaced by the so-called METÁR [Megujuló Támogatási Rendszer - Renewable Support System] system as of 1 January 2017 (i.e. applications can no longer be submitted, but the already granted FiT entitlements remain in force), which includes a new feed-in tariff system (METAR-FiT) up to 0.5 MW installed capacity, a "green premium without tendering" system for installed capacity between 0.5-1 MW and a "green premium granted through tendering" system for installed capacity over 1 MW." (Wolff Theiss)

"Under the FiT system, the generated electricity is sold to the TSO at a fixed price, whereas under the new METAR system the electricity is sold directly to traders or on the stock market with price correction. The HEA is the central agency for the FiT and METAR systems.

The FiT price, the supported quantity, and the support period, as well as the margin of METAR price correction are all defined by the HEA. The results of the solar boom in 2016, generated by the highly favorable and easily accessible FiT system, became visible in 2018, as the electricity generated by solar power plants increased by seventy-five percent (75%) compared to the previous year. Until the end of 2018 [2019], approximately 726 MW [958 MW] of solar power plants were put into operation." (Wolff Theiss)

In 2018, renewable-based generation capacities represented 12,34% of the total domestic installed electricity capacity. Due to the differences in the load factors of -especially weather-dependent- renewables, renewable technologies represented a slightly lower, 11,7% of gross annual power generation in 2018 (10,9% in 2017).

Figure 5.154 **Hungary's Power Generation Mix in terms of installed capacity (MW;%)**



Source: HEA - MAVIR - Data of the Hungarian Electricity System 2018

Solar Energy

The National Energy and Climate Plan (NECP) foresees increasing the installed solar capacities to 6.500 MW by 2030[17] and potentially to 10.000 MW by 2040.

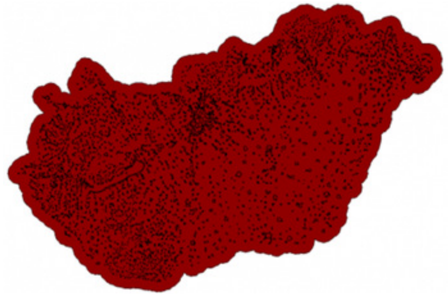
Wind Energy

Installing non-residential wind power plants is not outright forbidden, but such PPTs cannot be built inside or within 12 km from land for construction purposes[18].

17 The National Energy Strategy 2030 document foresees 6,000 MW
18 253/1997. (XII. 20.) - Government Decree

The following map illustrates (white area), where wind power plants can be constructed.

Map 5.46 **Designated areas for wind farm installations**



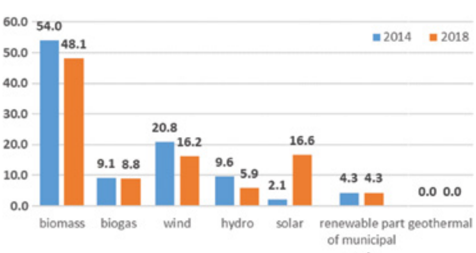
Source: Energiaklub - Szabad, csak nem lehet article [19]

Biomass and Waste

The share of renewable energy sources and waste in electricity consumption increased slightly (+ 0,7%) between 2014 and 2018.

Biomass dominates the renewable power generation in Hungary with almost half of the RES generation in 2018, however the share of solar generation already increased significantly, reaching 16,6% of RES generation in 2018; this increase is expected to continue due to the newly installed solar capacities (ca. 330MW end of 2017 vs. ca. 1.400 MW end of 2019 including household and commercial plants) which is expected to increase the share of RES generation as well.

Figure 5.155 **Share of renewable resources and waste in electricity consumption (2014 vs 2018) [%]**



Source: KSH/CSOH 5.7.3. Share of renewable resources and waste in electricity consumption (2000-) [%]; own elaboration

Geothermal Energy

Hungary has above average geothermal energy potential. The average geothermal gradient in Europe is 30-33°C/km, in Hungary it is 42-45°C/km, but can also reach 100°C/km at specific locations. The Hungarian geology is better suited for heat generation instead of electricity generation. In Iceland, the value can reach above 300°C/km in certain locations[20]. which is better suited for electricity generation. In 2018, primary production of geothermal heat was 140,1 ktoe: 54,69% of this heat (76,6 ktoe) is used for electricity (10,1 ktoe) and heat generation (66,5 ktoe) as transformation input. 28,3% (39,6 ktoe) was directly used by the agricultural and forestry sectors, whereas 15,58% (21,8 ktoe) was used by the commercial and public services sectors.

In 2018 15,57% of Hungary's housing stock was connected to district heating. The total number of consumers (households and others) were 679.187. In 2018, geothermal energy represented ca. 6,7% (54,7 ktoe) of total district heat production (811,5 ktoe)

The first geothermal power plant to produce electricity is a CHPP that produces 3 MWs of clean electricity and 7 MWth of geothermal heat for house heating and is located in Tura. The Energy Strategy foresees a higher utilization of the geothermal potential.

Hydroelectricity

There are two run-off river hydro power plants in Hungary on the river Tisza with a combined capacity of 41,7 MW. Additionally, there are some micro hydro power plants, which add up in total to 56,2 MW. There is additional hydro potential in Hungary, especially on the Danube and Drava rivers. However, since the stoppage of construction works of the Gabčíkovo-Nagymaros barrage system on the Hungarian side in 1989 due to environmental concerns and following termination of the contract with Czechoslovakia about the joint construction project in 1992, the unilateral commissioning

[19] https://energiabox.blog.hu/2016/09/16/szabad_csak_nem_lehet_733
[20] HO-01 well Stykkishólmur, W-Icelan - Kania, Jaroslaw & Ólafsson, Magnús. (2020). Chemical Characteristics of Thermal Fluids from Stykkishólmur, Iceland - https://www.researchgate.net/publication/265977036_Chemical_Characteristics_of_Thermal_Fluids_from_Stykkisholmur_Iceland

of the existing version on the Czechoslovak (today Slovakia) side, and the ensuing years of litigation, the topic has been politically charged and has not been widely discussed.

(f) Energy Efficiency and Cogeneration

Energy Efficiency

The goals for energy efficiency improvements in the National Energy 2030 document include decarbonization and decrease of import needs - along with keeping competitive end-user prices. One of the most important practical actions of the energy policy making is the application of "energy-efficiency first" principle[21] in infrastructure planning, policy making and investment decision making.

According to the Eurostat's energy balance, the primary energy consumption in 2018 was 24.489 ktoe. After transformation, transfer, and distribution losses, disregarding non-energy use, 18.543 ktoe got to the final consumers - final energy consumption, representing 75,72% of primary energy consumption. Primary energy consumption was 23.298 ktoe in 2015, (implicating a 5,1% increase in three years), whereas the final energy consumption was 17.400 ktoe (implicating a 6,5% increase in three years), represented 74,7% of the primary energy consumption. The above numbers imply increasing energy consumption, but also faster energy-efficiency improvements.

The goal of the Energy Strategy is that final energy consumption in 2030 shall not exceed the 2005 value of 18,7 Mtoe and any increase beyond 2030 shall be supplied from carbon neutral energy sources. The cumulated final energy consumption saving goal for the 2021-2030 period[22] is 7,9 Mtoe which would be a linear 0,8% saving, meaning an additional 167 ktoe per year.

The energy efficiency programs introduced between 2014-2020 would result in 72-96 ktoe baseline savings each year, thus, to achieve the target, it is necessary to increase the annual savings by approximately 300%. The strategy aims to achieve this goal via the energy efficiency obligation scheme[23], where energy distributors and retail energy sales companies are obliged to achieve cumulative end-use energy savings. In comparison with the neighboring countries, the household energy use, especially energy used for heating and cooling is relatively high. Presumably, the obligated parties can achieve energy savings the easiest in this area. The European Union goal[24] of having a highly energy efficient and CO_2 neutral building stock by 2050 shall also be observed.

The Széchenyi 2020 Program coordinates the allocation of funds[25] available from the Europe 2020 Program for Hungary between the 2014-2020 period. Each country prepares the so-called Operative Programs[26], which define the thematic areas where the funds can be utilized, in line with the pre-defined policy goals[27].

[21] In line with REGULATION (EU) 2018/1999 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December [21] 2018 on the Governance of the Energy Union and Climate Action
[22] in line with the Eurostat 2020-2030 SDG indicators methodology.
[23] Art.7. of the DIRECTIVE 2012/27/EU OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC
[24] Energy Performance of Buildings Directive 2010/31/EU (EPBD) and the Energy Efficiency Directive 2012/27/EU
[25] European Regional Development Fund, The European Social Fund, the Cohesion Fund and the European Maritime and Fisheries Fund
[26] https://ec.europa.eu/regional_policy/en/atlas/programmes/
[27] https://ec.europa.eu/eu2020/pdf/COMPLET%20EN%20BARROSO%20%20%20007%20-%20Europe%202020%20-%20EN%20version.pdf

Programs for energy efficiency are available among different operative programs, but most of the dedicated funds are assigned via the Environmental and Energy Efficiency OP[28](KEHOP), the Economic Development and Innovation Operational Program (GINOP)[29] Territorial and settlement development OP (TOP) and the Competitive Central-Hungary OP (VEKOP).

Each Operative Program defines priorities, within which tenders are published for actions to be supported.Such actions within the KEHOP include: *Building energetics development of public buildings*[30] or the Energy efficiency investments of budgetary institutions[31]; while through the GINOP another program concerns: *Credit aiming at increasing of energy efficiency and renewable energy use of residential buildings*[32] or *Support for building energetics developments aiming at increasing renewable energy use and energy efficiency*[33] [for SMEs].

The government's "Warmth of Home" program, aiming at supporting physical persons has, in recent years, featured programs for improving the energy performance of buildings and related renovation of condominiums and household appliance swap campaigns or heating modernization. Additionally, based on the corporate tax law[34], there is tax reduction available for companies' investments aiming at increasing the energy efficiency of their operations.

Apart from the above described support schemes the government aims at introducing more stringent building regulations. As of 1 January 2021[35], all new buildings (with specific exceptions and certain new public buildings even earlier) and various large renovations shall comply with the BB - Nearly zero-energy buildings (NZEB) standard[36].

Cogeneration

The work environment for cogeneration operators fundamentally changed in 2011, when the FiT scheme to support energy-efficient CHP introduced in 2002- was abolished, to re-focus on the support system for renewable technologies. After this energy policy shift, CHP producers had to re-evaluate their business models in order to compensate for the lost cashflow; some have closed or paused operations, others have formed regulatory centers, where they offer their flexibility to the TSO as a virtual power plant. On the output side, the heat has a regulated price, set each year before the heating season by HEA.

In 2018, according to the Eurostat energy balance, 16,6% of the gross electricity production was generated by main activity producer CHPs and autoproducer CHPs (ca[37]. 19,8% in 2010). If corrected by the autoproducers and the heat produced by the nuclear power plant, the share is 13,9% (18.8% in 2010).

[28] https://ec.europa.eu/regional_policy/en/atlas/programmes/2014-2020/hungary/2014hu16m1op001
[29] https://ec.europa.eu/regional_policy/en/atlas/programmes/2014-2020/hungary/2014hu16m0op001
[30] KEHOP5.2.2. - Középületek kiemelt épületenergetikai fejlesztései - ca 450m EUR
[31] KEHOP5.2.4 - Központi költségvetési szervek energiahatékonysági beruházásai - ca. 45m EUR
[32] GINOP8.4.1/A-17 - Lakóépületek energiahatékonyságának és megújuló energia felhasználásának növelését célzó hitel - ca. 315 mEUR
[33] GINOP4.1.4-19 - Megújuló energia használatát, energiahatékonyság növelését célzó épületenergetikai fejlesztések támogatása - ca. 60m EUR
[34] Para. 22/E 1996. évi LXXXI. törvény a társasági adóról és az osztalékadóról
[35] 7/2006. (V. 24.) TNM rendelet az épületek energetikai jellemzőinek meghatározásáról
[36] Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings
[37] NPP was considered as Main activity produced CHP in the statistics until 2016. Since 2017, a minor share of the generated electricity is registered as Main activity produced CHP, whereas most of the electricity production is registered as Main activity producer electricity only.

The National Energy Strategy 2030 foresees potential investment support for CHP generators which are integrated into the district heating system, especially since the increased winter production optimally supplements the higher photovoltaic production during the summer. Providing heat storage subvention, or eventually FiT-type support during the heating season to very efficiently operating CHP generators is also being considered.

Energy Investment Outlook

The ongoing energy investments have been partially described in the sectoral overviews. In this section, the expected and probable investments are summarized, where reference data and estimated costs are available.

Energy Infrastructure

In the power generation sector three major areas are expected where investments are already happening or are expected until 2030.
The Paks II Nuclear Power Plant is currently under permitting, nevertheless the construction of some service facilities has been tendered, awarded and started to. The cost of the project is estimated by the National Energy Strategy 2030 document to be around 12 bn EUR (4,000 bn HUF). The project will possibly be commissioned by the early 2030s, although no official target date has been published. The CAPEX estimates for the different proposed investments in the power grid under various scenarios of the National Ten-Year Network Development Plan are not published.

Nevertheless, a summary of necessary transmission system developments has been prepared by Energiaklub[38] in 2017, based on the scenarios of the previous energy strategy document.

The paper examines the grid development needs until 2030 in four categories:

• developments necessary to ensure security of supply to consumers	200-220 mEUR
• developments necessary to connect new power plants	45-130[39] mEUR
• cross-border developments[40]	61[41] mEUR
• developments necessary on the distribution system	2,250[42] mEUR

According to the energy strategy, the installed solar photometric capacities should reach 6 GW by 2030. Knowing that the installed capacity of commercial and household PVs reached 1,400 MW by the end of 2019, and assuming that 500MW more will have been built by the end of 2020, some 4,100 MW of new solar capacity can be expected to be installed until 2030. Assuming that the household to commercial share will be 20 to 80, and 0,5 MW[43]PPT's turnkey CAPEX[44] is 450,000 EUR (153 mHUF), and a household system's turnkey CAPEX is 1 EUR/Wp, the anticipated total investment until 2030 is ca. 3,8 bn EUR (840 mEUR household + 2,952 mEUR commercial PPT). Proposed projects on the gas transmission grid are available in the TSO's national TYNDP 2019 consultation document[45] without estimated CAPEX.

[38] Grid Development Needs in Hungary - Hálózatfejlesztési igények Magyarországon https://www.energiaklub.hu/files/study/Energiaklub_Bixpert_H%C3%A1l%C3%B3zatfejleszt%C3%A9si%20tanulm%C3%A1ny.pdf
[39] Included power plant projects have partially changed but other project ideas have emerged
[40] 750/400KV transformation and expansion of SK interconnection capacity
[41] ENTSO-E TYNDP references 81.63 mEUR for the HU-SK project CAPEX. Assuming 50% for Hungary and keeping the cost of the 750/400KV transformation at 20m EUR.
[42] Corrected compared to the figure in the text. Based on the analysis of annual DSO CAPEX/yr being 250 mill EUR/yr referenced in the text, extrapolated for the 2021-2030 period
[43] 600kWp nominal DC capacity with 500kW AC connection capacity, without the cost of the land including project development costs and assuming "close" connection possibility to DSO network
[44] Nominal, constant price with 340 HUF/EUR exchange rate
[45] https://fgsz.hu/file/documents/1/1528/2019_12_03_10_eves_fj_nyilvanos_konzultacio.pdf

Some of the cross-border projects are also available in the ENTSOG TYNDP 2020[46] document, with alternative CAPEX estimates. Capacity Auction and Open Season rulebook documents of FGSZ do provide CAPEX estimates or Present Value conditions to be met.

The projects which can potentially be realized by 2030 include:

- Enhancement and Development of the HU-SK interconnector (58,6 mEUR)[47]
- Hungary-Slovenia Interconnection (205 mEUR) [48]
- Compressor Station at Városföld town (20 mEUR) [49]
- Hungary-Ukraine development from interruptible to firm capacity [50] (N/A; max 10 mEUR)
- New Serbia-Hungary Interconnector [51] two versions (48/164 mEUR)
- Romanian-Hungarian reverse flow Hungarian section 2nd stage[52] (235 mEUR)
- Hungary-Austria Reverse Flow [53] (233,6 mEUR)

FGSZ has recently spent annually some 10-20 mEUR CAPEX per year, do without major project implementation[54]. The uncertainty at this stage is very high as to which projects will actually materialize, consequently, the final investment in the gas transmission system could potentially be anywhere between 158 mEUR[55] and 1154 mEUR[56] in the 2021-2030 time horizon.

The National Energy Strategy 2030 document foresees the entrance of new gas-based power generation capacities until 2030, partially to replace the lignite-based generation of the Mátra PPT. Additionally, existing CCGT capacities should be refurbished to increase their operational efficiency and prolong their life-span. For simplicity, two scenarios are considered; one where 500 MW new CCGT capacity enters the market, and another one where 1,000 MW new CCGT capacity enters the market. CAPEX of 1 MW of CCGT capacity is assumed to be 1,076 EUR/kW[57] . With these assumptions, the potential CAPEX is between 538 mEUR and 1,076 mEUR.

Energy Efficiency

With regards to energy efficiency investments, the new Green Bond Framework of Hungary referenced 23 bnHUF (ca 68 mEUR) state expenditure for Energy Efficiency in the 2018-2021 timeframe[58].Assuming doubling the annual expenditure for the 2022-2030 period, in total ca. 320 mEUR (109.25 bn HUF) state expenditure is expected in the 2021-2030 horizon for energy efficiency improvements and green buildings[59].

[46] https://www.entsog.eu/tyndp#entsog-ten-year-network-development-plan-2020
[47] ENTSOG estimate alternative CAPEX
[48] ENTSOG estimate alternative CAPEX
[49] ENTSOG estimate alternative CAPEX
[50] no CAPEX available but the necessary investments represent relatively low CAPEX of maximum 10 mEUR
[51] Prolongation of TurkStream and Gastrans (Serbia) pipeline projects to Hungary
[52] O/S failed, a successful O/S for the project would be needed, in case the Romanian Black See gas potential is developed
[53] Successful O/S for the HU>AT project and
[54] Based on Annual Reports of FGSZ - https://fgsz.hu/en/transparency-information/reports-and-announcement
[55] Assuming that the Városföld CS, SR-HU stage I and HU-UA firm projects will at least be realized until 2030, along with the 10 mEUR CAPEX/yr.
[56] All projects are realized along with 20 mEUR CAPEX from 2021 to 2030 which is highly improbable.
[57] Projected Cost of Generating Electricity - 2015, IEA Table 3.2 Hungary - adjusted for 2025 prices. Exchange rate is assumed at 1,1 USD/EUR
[58] https://www.akk.hu/en/page/green-bond
[59] Subsidies to purchase energy-efficient electrical appliances (Home Warming Program) - Public building renovation - Support to farm owners and local institutions to implement energy efficiency measures - Subsidies to SMEs focusing on energy efficiency solutions

Simply assuming a 100% multiplicator (50% support intensity), the total, nation/wide energy efficiency investment generated by this state expenditure would be ca. 640 mEUR until 2030. This figure does not include private investments independent from the above state program. An Electric Vehicle support scheme was introduced in 2016.

Currently 5 bnHUF (14.1 mEUR) is available for fully electric vehicles, electric taxis, and electric mopeds within the ongoing scheme. Maximum support intensity is 2.5 mHUF (ca. 7350 EUR per vehicle)[60].

Assuming that the annual 14.1 mEUR remains available each year through 2021-2030, a total of 141 mEUR can be handed out between 2021 and 2030, realising ca. 560 mEUR investment in electric vehicles (ca. 19,000 cars).

The Climate and Nature Protection Action Plan 2020[61] document foresees the installation of one million electric smart meters by 2030. Assuming 100 EUR wholesale cost per meter, this plan results in a country/wide investment of 100 mEUR.

The Green Bus Program in the Action Plan foresees that only electric buses can be procured in cities with a population over 25.000 from 2022 onwards. The proposed budget for this program is ca 105 mEUR until 2030.

The National Energy Strategy 2030 Document estimates that, in order to reach the 2030 energy and climate goals, additional investments should reach 44.5 bn EUR until 2030, without the Paks II NPP.

[60] For vehicles costing max 11 mHUF ca 32,350 EUR.

[61] https://www.kormany.hu/download/9/d4/c1000/ITM_Klima_es_Termeszetvedelmi_Akcioterv.pdf#!DocumentBrowse
https://tyndp.entsoe.eu/tyndp2018/projects/
https://fgsz.hu/file/documents/1/1528/2019_12_03_10_eves_fj_nyilvanos_konzultacio.pdf
https://fgsz.hu/en/transparency-information/reports-and-announcement
https://www.akk.hu/en/page/green-bond
https://www.kormany.hu/download/9/d4/c1000/ITM_Klima_es_Termeszetvedelmi_Akcioterv.pdf#!DocumentBrowse

References

(1) *https://www.kormany.hu/hu/nemzetgazdasagi-miniszterium https://www.kormany.hu/hu/innovacios-es-technologiai-miniszterium*

(2) *http://www.mekh.hu/introduction*

(3) *https://erranet.org/member/hea-hungary/*

(4) *http://www.oah.hu/web/v3/HAEAportal.nsf/web?openagent&menu=01&submenu=1_0*

(5) *https://fgsz.hu/en/about-fgsz/activities-business-policy/mission-vision*

(6) *http://mavir.hu/web/mavir-en/mavir-ltd*

(7) *http://www.mekh.hu/annual-data*

(8) *http://www.ksh.hu/engstadat?lang=en*

(9) *http://mekh.hu/download/2/c2/c0000/2_2_annual_supply_of_petroleum_and_petroleum_products_annual_2018.xlsx*

(10. *https://webstore.iea.org/energy-policies-of-iea-countries-hungary-2017-review*

(11) *https://molgroup.info/en/our-business/downstream/mol-group-downstream*

(12) *https://www.omv.hu/hu-hu/toltoallomasaink*

(13) *https://www.shell.hu/autosok/shell-station-locator.html#iframe=Lz9sb2NhbGU9aHVfSFUjL0A0Ny4xNTUyNSwxNi44NDkwOCw3eg*

(14) *https://lukoil.hu/toltoallomasaink/*

(15) *https://map.mbfsz.gov.hu/asvanyvagyon_kataszter/*

(16) *http://www.ksh.hu/apps/shop.kiadvany?p_kiadvany_id=1050680&p_temakor_kod=KSH&p_lang=HU*

(17) *https://fgsz.hu/file/documents/1/1402/a_magyar_foldgazrendszer_2018_evi_adatai.pdf*

(18) *https://www.gie.eu/index.php/gie-publications/maps-data/gse-storage-map*

(19) *http://mekh.hu/foldgazipari-tarsasagok-2020-evi-adatai*

(20) *https://hudex.hu/uploads/Term%C3%A9kek/G%C3%A1z/HUDEX%20Natural%20Gas%201.Segment%20Product%20List%20and%20Specification%2020191001.pdf*

(21) *https://fgsz.hu/file/documents/1/1528/2019_12_03_10_eves_fj_nyilvanos_konzultacio.pdf*

(22) *http://mekh.hu/annual-data*

(23) *http://mekh.hu/download/4/c2/c0000/4_2_gross_electricity_production_2014_2018.xlsx*

(24) *http://mekh.hu/a-magyar-villamosenergia-rendszer-ver-2018-evi-adatai*

(25) *https://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/main.html*

(26) *https://hupx.hu/uploads/Rolunk/C%C3%A9ginform%C3%A1ci%C3%B3/HUPX%20Company%20Brochure_web_2020jan.pdf*

(27) *http://www.ksh.hu/docs/eng/xstadat/xstadat_annual/i_qe002.html?lang=en*

(28) *http://www.ksh.hu/docs/eng/xstadat/xstadat_annual/i_ui011a.html?lang=en*

(29) *https://www.wolftheiss.com/knowledge/wolf-theiss-guides/detail/the-wolf-theiss-guide-to-generating-electricity-from-renewable-sources-in-central-eastern-southe/*

(30) *http://mekh.hu/a-magyar-villamosenergia-rendszer-ver-2018-evi-adatai*

(31) *http://www.ksh.hu/docs/eng/xstadat/xstadat_annual/i_ui011b.html*

(32) *http://www.mekh.hu/download/e/b2/c0000/7_4_orszagos_eves_%20Eurostat_%20tipusu_%20reszletes_%20energiamerleg_2014_2018.xlsx*

(33) *http://www.mekh.hu/download/f/0f/30000/magyarorszag_geotermikus_felmerese_2016.pdf*

(34) *http://www.mekh.hu/download/0/62/c0000/a_magyar_tavhoszektor_2018_evi_adatai.pdf*

(35) *https://ksorka.com/first-geothermal-power-plant-hungary/*

(36) *https://web.archive.org/web/20130821160750/http://www.bosnagymaros.hu/*

ISRAEL

Israel

Economic and Political Background

Activity softened in the fourth quarter of 2020, with GDP expanding 6.3% in seasonally-adjusted annualized rate (SAAR) terms (Q3: +41.5% SAAR). However, the economy performed fairly well relative to other developed economies in the period and shrank a mere 2.3% over 2020 as a whole (2019: +3.4% y-o-y). Resilience in Q4 was likely due to firms being better adapted to restrictions and more able to shift their activity online, as well as citizens' reduced compliance with measures.

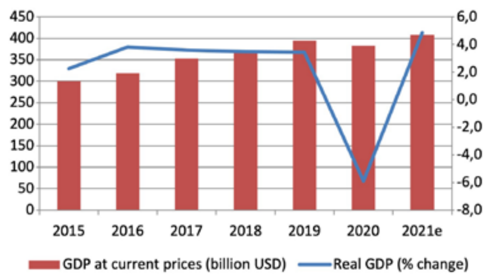
Private consumption increased 18.2% in the fourth quarter, which was below the third quarter's 42.2% expansion, likely weighed on by the second lockdown early in the quarter. Government spending grew at the fastest rate on record, expanding 26.0% (Q3: +8.5% SAAR). Meanwhile, fixed investment growth improved to 66.1% in Q4, up from the 17.4% expansion in the prior quarter and driven by surging industrial investment.

Exports of goods and services fell 4.9% on a SAAR basis in the fourth quarter, which contrasted the third quarter's 67.6% expansion. Conversely, imports of goods and services bounced back, growing 88.5% in Q4 (Q3: -1.3% SAAR). The reading was driven by surging car imports amid frontloading ahead of tax hikes at the start of 2021.

On an annual basis, GDP declined 1.3% in Q4, down from the previous quarter's 1.2% decrease.

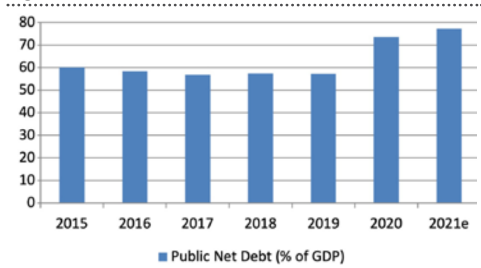
Looking ahead, activity in the early part of Q1 will likely be held back by the third lockdown. However, the country's record-beating vaccination pace has allowed a relaxation of restrictions from early February, which, coupled with recoveries abroad, should spur momentum through the rest of the year. IMF estimates that Israel's GDP will expand by 4.9% in 2021, significantly higher than -5.9% in 2020. On April 20, 2021, Prime Minister Benjamin Netanyahu called for direct polls to choose Israel's next leader, as he struggles to form a coalition following four general elections in less than two years. Netanyahu's rightwing Likud won 30 seats in elections held in March, making his party the largest in Israel's 120-seat parliament. He has support from ultra-Orthodox parties and an alliance of hardline nationalist factions, but has not been able to cobble together a 61-seat majority. Challengers to Netanyahu, including Yair Lapid of the centrist Yesh Atid party, are waiting in the wings to form a government to replace Israel's longest-serving leader, who has been in office for 12 consecutive years.

Figure 5.156 **Israel's GDP and its annual GDP growth**



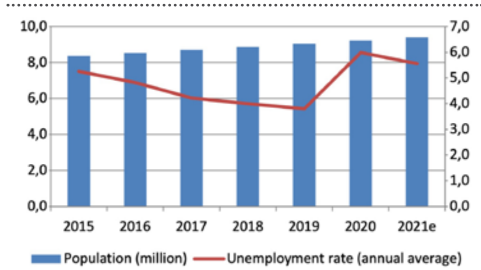
Source: IMF World Energy Outlook (October 2020)

Figure 5.157 **Israel's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.158 **Israel's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy - Country's energy policy, its objectives and strategy

Over the last two years, Israel's energy policy has been focused mainly on reducing the emissions of pollution and GHG in the power sector, because this is the sector which is the easiest to have the greatest impact. A second goal has been to increase competition, in both the power and natural gas markets through the introduction of the private sector, as well as to reduce prices in both these markets.

Since Israel has large volumes of natural gas (1,000 bcm discovered to date in a market which consumes 11.5 bcm a year in 2019), the government's goal is to reach more than 80% natural gas and 17% renewable energy in the power sector by 2030 and minimum coal usage. In November 2019, the Ministry of Energy, under pressure, stated that the renewable target will be revised and may increase to 25%-30% by 2030 and zero coal generation already by 2025. These targets however are ambitious and not yet backed by a government decision.
Thus, a strong trend in Israel with special emphasis at the end of 2019 is to increase renewable energy, with special focus on solar PV (with two existing thermal power station, at the Ashalim station).

The transition to natural gas in the Israeli economy between 2013-2018 has led to a 62% reduction in SOX and 50% reduction in NOX emissions. Between 2013 and 2018, the emission of these pollutants declined by 62% and 50% respectively. The decline in emission of sulphur oxide and nitrogen dioxide has saved the Israeli economy $4 billion during this period (Gas Forum).

On the transportation front, statements have been made by which as of 2030 only new electric or gas operated vehicles (CNG) will be able to be imported into Israel. Yet again, although the country is making the first initial steps to establish CNG refueling stations and electricity recharging points, this infrastructure is still in the initial stages of development. The barriers to electric vehicles stem from the fact that the state does not have a detailed master plan for the energy market, only sporadic decisions whose validity is unclear. As a result, Israel lacks comprehensive regulation for automakers, charging station owners and consumers, as well as specific assignments for IEC so it can expand its systems to deal with the sharp spikes in electricity demands. Another issue will be the need for the treasury to find alternative source of revenue for the 18 billion NIS in annual revenues from the gasoline excise tax (over $5 billion).

Competition in the natural gas market will break-through as of January 2020, as the 610 bcm Leviathan gas field starts commercial production (1st gas flowed on 31.12.2019) and will increase to three independent gas suppliers by by mid-2022 as the Greek-British company's Energean's Karish field comes online. In this respect, Israel will have 3 independent and separate gas pipelines coming onshore into Israel with a capacity to supply c-30 bcm a year, by mid-2021, plus an FSRU to import LNG in case of emergency or for spot needs. Aw a result of the competition, the Israel;i IPP's and industrial consumers enjoy longterm contracts with stable prices around $4/mmbtu even during the peak of the energy crisis while European countries pay even 10 times higher.
In the power sector, competition is increasing also, with private power producers generating over 30% of the electricity generation by the end of 2018, with this figure growing fast as the state-owned utility (IEC) is to sell 5 power stations containing 19 power generation units over the next 5 years to the private sector. The main sector, however, is indeed the country's natural gas market and between 2013 (when the Tamar field came on line) and until the end of 2018, natural gas has saved over $17 billion in energy costs.

Governmental institutions

Key institutions and their role in policy making.

The main governmental institutions that relate to energy are the Ministry of Energy which now includes also the two main regulators – The

Natural Gas Authority as the gas regulator – and the Public Utility Authority (Electricity) which is the electricity regulator; the Ministry of Finance and the Ministry of Environmental Protection. Two other important government owned companies are Israel Electric Corporation (IEC) which is the main electricity utility company and Israel Natural Gas Lines (INGL) which is the monopoly natural gas transmission system operator.

Ministry of Energy – The Ministry of Energy is responsible for all of Israel's energy sectors and its natural resources, including electricity, fuel, LPG, natural gas, conservation of energy, water, sewage, petroleum explorations, minerals, earth science, marine research and more. The Ministry supervises the public and private bodies operating in these fields, while regulating the market, protecting the consumer, and protecting the environment.

Ministry of Finance – The Ministry of Finance is, inter alia, responsible for determining and implementing economic policy in Israel. In this respect it is the entity that greatly determines and provides budgets for energy related issues that range from reform in the electricity sector, to grants for the deployment of natural gas distribution pipelines, as well as for R&D in energy novelty.

Public Utility Authority (PUA) – In 1996, the Israeli Electricity Market Regulatory Authority was established, with the objective to, inter alia, balance between maintenance of a fair rate framework to be imposed upon electricity consumers, and support of private power plants, as well as determining electricity tariffs in a competitive and equitable manner.

Natural Gas Authority (NGA) – Was established in 2004 by virtue of the Natural Gas Sector Law 2002, and is the regulator that promotes long-term strategic planning, grants licenses and supervises the licensees in the natural gas mid- downstream segments, sets tariffs and standards for the provision of services, clarifies disagreements and determines arrangements between the players in the market, and handles consumers' complaints.

Ministry of Environmental Protection – Insofar as energy is concerned, its focus is on the reduction of greenhouse gas emissions, financial incentives that encourage greenhouse gas reduction and promoting the decreasing consumption of electricity and the use of renewable energies.

Israel Electricity Corporation (IEC) – IEC is owned by the State of Israel (99.8%). Its activities include the generation, transmission and transformation, distribution, supply and sale of electricity. IEC owns and operates 17 power stations with 61 generating units.

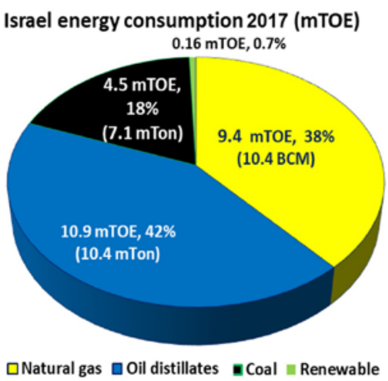
Israel Natural Gas Transmission (INGL) – The national transmission network of Israel Natural Gas Lines is the main artery for natural gas transmission in Israel. The network includes the western, central, northern and southern trunk lines, totaling 750 km and there are plans underway to further develop and expand the network.

Energy Demand and Supply

Israel's energy (2018) is based 42% on oil, 38% on natural gas, 18% on coal and only 1% renewable generation (2.9% actual renewable generation in power sector). These figures, however, are due to change as coal becomes phased out and is replaced gradually by natural gas and renewables. In terms of renewables, the main real source of supply is solar with minimum wind facility, although one hurdles has been removed recently in the form of opposition from the Ministry of Defence. Israel has no hydro or geothermal power. Israel also has no nuclear power and no plans to construct any nuclear power stations in the near future.

In terms of natural gas consumption, demand for gas has hitherto been restricted by the lack of availability of supplies to grow in line with demand, so that consumption will reach 11.2 bcm a year in 2019 (full year), comprised mainly of gas from the local Tamar field and c-0.7 bcm of LNG imports. As of 2020, however, with the start of commercial production from the Leviathan field, consumption will be able to grow organically based on demand (see graphs below). In addition to the electricity sector, natural gas is the primary energy source for Israeli industry connected to gas transmission infrastructure. For now, the use of natural gas in small- and medium-sized industrial plants is still in its early stages, whilst residential, commercial and gas in transportation has not yet really taken off, partially due to the still limited scope of development of the low-pressure, privately owned, distribution networks, albeit CNG is starting to be used in transportation in Israel. The first inroads of natural gas and electricity in the transportation sector, was facilitated thanks to supportive governmental regulations and policies, directed towards ceasing to use oil and to transition to natural gas and electricity for transportation. The government's goal is that in the industrial sector, 95% of the energy and steam required will be generated from natural gas as of 2030. Although Israel has a lot of energy in the form of natural gas, Israel has hitherto only achieved just over 40% energy independence. The objective in the next few years is that more than 50% of the energy will be locally produced (increase use of natural gas and renewables and reduced coal imports and use in power generation and liquid fuels in transportation).

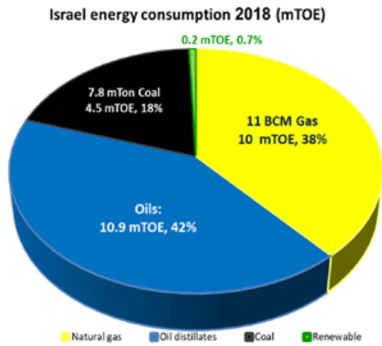
Figure 5.159 **Israel's total Energy Consumption and Electricity Generation in 2017**



Electricity Generation - 2017	
Total:	68,309 million KW/h
Gas:	43,837 million KW/h
Of that IPP (mostly gas):	17,735 million KW/h
Coal:	22,052 million KW/h
Renewables:	1,786 million KW/h

Source: Israel's Ministry of Energy

Figure 5.160 **Israel's total Energy Consumption and Electricity Generation in 2018**



Electricity Generation - 2018	
Total:	69,644 million KW/h
Gas:	46,767 million KW/h
Of that IPP (mostly gas):	19,701 million KW/h
Coal:	22,599 million KW/h
Renewables:	2,038 million KW/h

Source: Israel's Ministry of Energy

Oil and Petroleum Productions

In 2018, Israel imported about 100 million barrels of oil, out of which it consumed 79 million barrels. The remainder was re-exported mostly as heavy fuel oil. Most of the oil is imported from Azerbaijan via the BTC pipeline, plus some spot supplies from other countries. Most of the exports are to the Mediterreanan region and Africa.

Israel is 98% dependent on imports for its crude oil, with the remaining 2% stemming from condensates produced from the natural gas fields and a small onshore oil field. Insofar as distilliates are concerned, Israel is mostly independent, with some imports of LPG.

Israel is mostly dependent on imports of oil since it has minimal reserves and exploration in this respect. The country however preserves emergency reserves of crude oil and distillates

Table 5.123 **Distillates consumption 2015-2018**

consumptions of distillates in thousands of tons

	2018	2017	2016	2015
LPG	907	917	790	774
Benzene components	3,239	3,234	3,169	3,027
Benzene	460	312	470	397
naphtha	453	527	428	510
kerosene	1,358	1,299	1,186	1,124
diesel	3,293	3,445	3,292	3,227
HFO	782	741	741	767
betumen	311	312	286	244
HVGO	13	42	44	49
Total	**10,815**	**10,830**	**10,407**	**10,118**

Source: Israel's Ministry of Energy

Israel has two oil refineries, the biggest one being the Bazan refinery in Haifa with a 9.8mn t/y capacity (197,000 b/d) and the Paz Baza refinery in Ashdod with a 5mn t/y capacity (100,000 b/d). The main new projects planned in this respect relate to the closure of the main Haifa refinery and the establishment of a more modern facility in a more remote area of the country. This is a long-term plan which if realized will take at least a decade to accomplish.

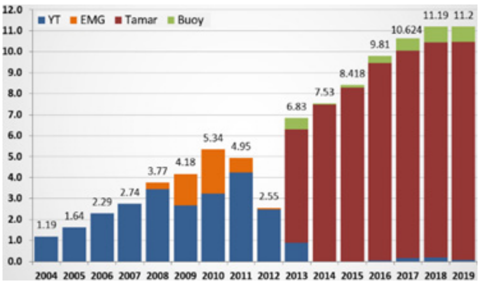
Natural Gas

- Gas consumption in 2018 (including exports) totalled 11.11 BCM – a 7% increase from 2017; the volume is anticipated to be the same in 2019.
- 95% of the gas (10.44 BCM) was supplied by Tamar and the remaining 0.67 BCM was imported as LNG via an FSRU.
- Gas consumption by the industry rose by 12% compared with 2017 to 2.02 BCM, following the connection of new consumers to the distribution network.
- Since April 2013, with the start of supply from Tamar and construction of the LNG buoy, gas consumption in Israel has grown by 63%.
- As of the end of 2018, five large conventional IPPs and five factories (cogeneration facilities) are connected to the gas transmission system in addition to IEC's stations.
- 15 large industrial consumers have been connected to the transmission system, 69 consumers have been connected to the distribution network (11 in 2018) and 7 consumers consume CNG supplied by trucks.
- Distribution network and LPG consumers consumed a total of 0.24 BCM in 2018, a 21% increase from 0.2 BCM in 2017. In 2019, distribution network and LPG consumers are due to consume more than 0.3 BCM. 90% of these consumers are located in the south.
- As of end 2018, INGL (high pressure transmission system) has constructed about 750 km of transmission lines whilst the low pressure distribution pipelines total 350 km.
- The total saving for the market from the transition to gas between 2004 and the end of 2018 is estimated at 63.7 billion NIS, 49 billion of which is in the electricity sector; Gas consumption has saved the Israeli industry 14.7 billion NIS.
- Between 2004 and the end of 2018, 83 BCM of gas were supplied in place of coal and distillates.
- The highest daily consumption rate in 2018 was recorded on 15.7.2018 and totalled 37,202 CM; An hourly record of 1,762 CM (63,395 MMBTU) was on 28.1.2018. The maximum hourly supply from Tamar in 2018 was on 9.7.2018 at 9:00 and reached 1,353 MCM (48,684 MMBTU). The maximum hourly supply capacity from Tamar is 49,500 MMBTU.
- The average hourly and daily flow rates were 9 MCM and 28.6 MCM, respectively.
- 0.67 BCM were supplied from the LNG buoy in 2018 compared with 0.52 BCM in 2017, mainly during the summer.
- The Ministry of Energy collected 860 million NIS in royalties on gas during 2018.
- Leviathan's development has been completed and is in full commercial operation since 1.1.2020.
- Energean remains on track to deliver first gas from the 1.4 TCF Karish development project in mid-2022. At 30 September 2021, the project was approximately 91.8% complete. The "Energean Power" FPSO will be the first gas FPSO ever to have operated in the Mediterranean, and is expected to leave the yard in Singapore for Israel in 1Q 2022. This journey will take around 35 days. Hook-up and pre-first gas commissioning will then take approximately three months.
- In May 2018, the Ministry of Energy published a tender to accelerate the deployment of the distribution network which includes three parts: long-term loans for building lines;

long-term loans for increasing throughput; and long-term loans for building pressure reduction stations. The budget for the first round is 200 million NIS.

- The Ministry published a tender for CNG fuelling stations in the amount of 100 million NIS; and a tender for connecting distant gas consumers in the amount of 50 million NIS.

Figure 5.161 **Gas Supply 2004-2019**



Source: Delek Drilling

Solid Fuels

The only use of solid fuels in Israel is of coal for electricity generation. Israel, however, does not have any coal production or deposits and all coal consumed is thus importer by Israel Electric Company (IEC). The main suppliers of coal are from south Africa, Colombia and Russia.

The use of coal has been sharply decreasing in Israel over the last few years, with the latest government goal to stop using coal on a regular basis by 2025-2026 and just preserve the coal stations' ability to generate with coal in case of emergency (preserve the use of dual fuel generation stations).

In 2018 (same figures anticipated for 2019), the consumption of coal was 7.8 million tons, producing 20.5 TW/h, 29.6% of total electricity generation. Coal consumption in 2017 was 8.2 million tons, in 2016: 9.1 million tons and in 2015: 10.7 million tons. All this compares to 14 million tons consumed in 2012 (63.4% of total electricity generation) prior to the commercial production of the Tamar field. Coal facilities today consist of 10 coal units (at 2 power station sites in Hadera and Ashkelon) with a total generation capacity of 4,840 MW, operating at an average load of 49%. The first phase target is to shut down 1,440 MW (4 out of the units) by June 2022, whilst the remaining 3,400 MW will be converted to dual-fuel with natural gas as the main fuel by 2025-26.

Electricity

In 2018, State owned Israel Electric Corporation (IEC) generated 68.7% of the electricity in the market (71% in 2017, 72% in 2016), IPPs thus generated 31.3%.

The total electricity consumption in Israel (including the Palestinian Territories) was 69,644 MW.

In 2018, IPPs were 26% of the installed capacity but generated 31% of the electricity (in 2017, IPPs were 24% of installed capacity and generated 29% of the electricity). Out of the IPPs, natural gas amounted to an installed capacity of 19%, whilst generating 28% of the market's electricity amounting to 19,700 MW. IEC has a total installed capacity of 13,335 MW. All of the electricity consumed in Israel is generated locally with no imports from oversees. In addition, Israel does not export any electricity to neighbouring countries. Thus, there are no cross-border interconnections and nothing in this respect is planned.

Israel has no nuclear or hydro power generation plants and nothing is planned in the near future in this respect. In terms of future plans, about 800 MWs of new CCGT and cogeneration (natural gas operated) power stations are due to come online within the next 18 months. In addition, 300 MW of pumped storage facilities are due to start operating in the next year.

The annual growth in electricity consumption in Israel has historically been over the last 20 years about 3%/p.a. However, since 2012 growth was reduced to 2.23%/p.a. and it is expected to remain at this level over the next few years. This is on a par with population growth of 2% per annum, but lower than the growth in GDP per capita which is about 3.5% per annum.

Table 5.124 **Electricity installed capacity and production 2017-2018**

	31.12.18		31.12.17	
	Generated energy (thousands of MW)	% of total generated energy in sector	Generated energy (thousands of MW)	% of total generated energy in sector
Israel Electric Company	47,905	69%	48,788	71%
Private electricity producers (without renewable energies)	19,701	28%	17,735	26%
Renewable energies	2,038	3%	1,786	3%
Private electricity producers (with renewable energies)	21,739	31%	19,521	29%
Total in the sector	69,644	100%	68,309	100%

	31.12.18		31.12.17	
	Installed capacity (MW)	% of total installed capacity in sector	Installed capacity (MW)	% of total installed capacity in sector
Israel Electric Company	13,335	74%	13,617	77%
Private electricity producers (without renewable energies)	3,334	19%	3,199	18%
Renewable energies	1,303	7%	946	5%
Private electricity producers (with renewable energies)	4,637	26%	4,145	23%
Total in the sector	17,972	100%	17,762	100%

Source: IEC 2018 Financial Reports

Table 5.125 **Electricity consumption forecast**

Bil. kWh	2015	2020	2025	2030	2035	2040	CAGR 2015-2040
Residential	17.6	20.6	24.9	30.7	36.8	42.7	**3.6%**
Commercial & Public	17.6	20.7	25.0	30.4	36.4	42.9	**3.6%**
Industry	14.3	16.4	18.6	21.3	24.0	26.7	**2.5%**
Agriculture	1.7	1.9	2.1	2.3	2.7	3.0	**2.3%**
Desalination & Water Pumping	4.0	5.1	6.4	7.8	9.0	10.2	**3.8%**
Rail Electrification		0.4	0.8	1.2	1.5	1.8	**-**
Electric Vehicles		0.4	1.0	2.5	3.2	3.8	**-**
Total Israel	**55.2**	**65.4**	**79.0**	**96.1**	**113.5**	**131.1**	**3.5%**
Palestinians	*5.2*	*6.7*	*8.9*	*13.4*	*20.1*	*30.2*	*7.3%*

Source: BDO

Figure 5.162 **Electricity installed capacity & peak demand**

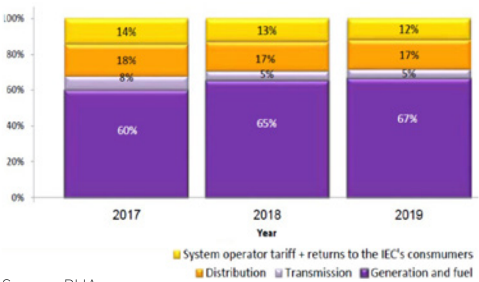
Source: PUA

Electricity tariffs

All the various elements of the electricity tariffs (generation, connections, T&D, supply) are determined by the electricity regulator (PUA). Israeli electricity is priced in two ways: residential consumers ordinarily pay a "uniform tariff," which is currently 47 agorot/kWh (Dec 2019). Businesses and factories often pay a tariff that varies according to the season and hour, known as "time of use".

In January 2020, the domestic electricity tariff fell by 4.1% to 45.05 agorot/KWH (about $0.13). The main reasons for the fall is due to lower fuel prices (international coal prices, natural gas in the form of spot purchases from the Leviathan field), as well as revenues from the sale of the first IEC power station sold to the private sector as part of the reform in the electricity market.

Figure 5.163 **Tariff structure**



Source: PUA

Renewables

During 1926-1932 a renewable/hydro station (18 MW) was built on the Jordan river in the land of Israel (under the British mandate) and was the main power source for the country. The station was destroyed during the War of Independence (1948) and never renewed its operations.

In the 1950's, Israel was among the pioneer's countries to use thermo-solar panels to heat water, mainly for domestic use. To this day, most residential premises in the country are obliged to install thermo-solar panels.

Starting in 2009, the government initiated several programs to promote renewable energy: solar, wind and biomass, mainly by issuing tenders and setting attractive feed-in-tariffs.

Renewable capacity at the end of 2018 was 1,303 MW or 7.2%; in 2017 the renewable capacity was 946 MW, 5.3%. The Ministry of Environmental Protection and the Electricity Authority within the Ministry of Energy stated that by the end of 2019, renewable capacity would reach more than 2,000 MW and was expected to double again by the end of 2020.

In 2018, renewable energy generation amounted to 2,038 MW/h or only 2.9% of de facto total electricity generation. In 2017 the figure was 1,786 MW/h or 2.6% of total generation. The Ministry of Environmental Protection and the Electricity Authority stated that by the end of 2020 renewable energy generation would reach 10% of total generation.

The government targets in this respect were set in 2015, following the "Paris Climate Summit".

The government stated that "Renewable energy will supply 10% of electricity generation by 2020 and 17% of electricity generation by 2030". In November 2019, the Minister of Energy stated that the government is considering revising these national targets for 2030 to be 25-30% of electricity generation.
Renewable energy sources:

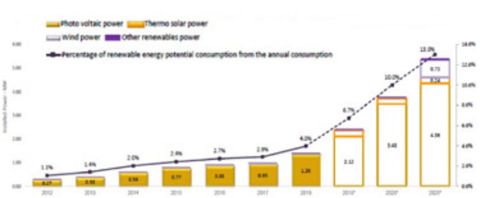
- Photovoltaic - Most of the existing (1,500 MW) and future renewable energy is solar PV.
- Thermo-solar - 2 existing power plants, 110 MW and 121 MW, operate at the Ashalim station.
- Wind – a 120 MW station is under construction in the Golan Heights and a number of other projects are being discussed. These encounter opposition from local citizens (NIMBY), environmentalist (destructive to birds) and the Ministry of Defence (impedes the air force's ability to manoeuvre).

- Hydro - Presently, Israel does not have classical hydro plants; however it is in advanced stages of constructing two pumped storage facilities for 300 MW and 340 MW respectively. A third such project is being discussed.
- Geothermal - Israel does not have geothermal energy.

The focus for the future expansion is on PV. Until 2-3 years ago, the high cost of such technology was the main obstacle for further expansion of PV. As the price of PV systems dropped sharply the main drawback for solar plants in Israel is now the amount of land it requires, an acute issue in a country of extreme high population density as is Israel. To reach a renewable/solar rate of 30% (and lacking most other renewable options besides PV), Israel needs to attain a PV capacity of 18,000 MWs. Such a scope requires a footprint of 180,000 dunams. Israel suffers from a shortage of open spaces, with such land only available in the far south, which would in turn require huge investment (and losses) to transmit the power to the main centres of demand in the centre and north of the country.

The combination of these two barriers means that it will be extremely difficult to attain the new target set for 2030, until and unless new break-through technology and/or storage is developed.

Figure 5.164 **Electricity from renewables**



Source: PUA

Energy Efficiency

A new program based on the "Guidance for Energy Efficiency Action Plans under Directive 2012/27/EU", was approved by Israeli government decision #3269 dated 17.12.2017.

This reduces the government's 2030 electricity consumption target to 80 TW/h compared to the "business as usual" scenario, by which electricity generation in Israel would reach 96 TW/h in 2030.

The government program consists of several supportive tools:

- Financial: grants, and subsidies in the form of loans and tax benefits
- Regulation: energy labelling and minimum energy performance standard (MEPS)
- Public awareness

As far as loans are concerned, a specialized fund has been established with $145 million for qualified energy saving projects to be distributed via a tender process. Total energy consumption was divided as per the relevant consumption sectors: residential, commercial and public, industrial and water, transportation, agriculture and the Palestinian Authority, with each sector being examined for its inherent potential for energy savings, suitable policy tools, costs and expected savings.

The building sector is split between residential, commercial & public. The main targets for conservation and efficiency measures in Israel are: air-conditioner systems, lighting (including street lighting), general appliances' efficiency and solar water heaters.

Cogeneration: In 2018 (IEC report), 6 big co-generation power plants with a total capacity of 761 MW were connected to the grid and became operational. An additional 3 co-generation power plants, with a total capacity of 218 MW are in the commissioning stage (as of end 2019). Several small size systems are also operating.

The regulatory framework under which the co-generation projects were established states that the heat and steam generated can be used for either self-use or for onward sale to other end-consumers. The surplus power can be sold to any power consumer via IEC's national grid, whilst the steam can be provided to industrial consumers in the close vicinity of the co-gen station. The prices of both these products are not controlled by regulators, but for commercial reasons have been set by the owners at a discount to the IEC controlled tariff.

Due to a relatively high degree of surplus electricity generation capacity in the market (over 20%), during those hours when the IPPs are unable to sell their surplus output to end-consumers, they are compensated in the form of a commitment by the electricity system manager to buy the energy set at a tariff that has been pre-determined on a project-by-project basis. In times of electricity shortage or emergency, the plants will be dispatched by the electricity system manager.

In 2018, the co-generation regulations were amended so that going forward bilateral sale of electricity will no longer be possible for new co-generation projects and all electricity, other than for self-consumption, must be sold to the "electricity system manager on a half-hourly basis". In addition, the ministry is promoting small size cogeneration projects (3-16 MW). In this respect, a quota of up to 750 MW was published for tendering.

Energy Investment Outlook

Natural Gas

In 2020, the Leviathan gas field came on line with a total investment of $3.75 billion.
In mid. 2022, the Karish gas field will come on line with a total investment of $2.1 billion.

Insofar as natural gas transmission and distribution is concerned, it is expected that the government owned Israel Natural Gas Transmission Company will invest $100 million every year over at least the next 5 years to expand the already 750 km long high pressure transmission system. In the low pressure distribution sector, the 6 private companies with local regional distribution monopolies have an accumulated commitment to invest the same kind of sum (i.e. $100 million per year over the next half a decade).

Oil and Gas Exploration

In terms of gas exploration, there are 18 offshore gas exploration permits which have been granted between 2017 and 2019. In 2019, Energean discovered (April) and successfully appraised (November) the 1.2 TCF Karish North Field, which is expected to come on stream in 2H 2021. Over the next 5 years, the holders of these permits will be conducting a variety of activities ranging from seismic surveys and interpretation with little commitment to drill any new wells during this initial period. Investment in this sector will thus be limited over the next few years.

Electricity

However, Energean has planned to start in 1Q 2022 a drilling campaign, consisting of 3 firm wells and 2 optional, targeting 1 billion of oil equivalent resources (more than 80% in gas). If discovered, this gas could be used also for export purposes.

By 2022, IEC will construct a new 1,200 MW CCGT station at a cost of about $1.2 billion.
IPPs, cogeneration and pumped storage facilities will be investing about $2 billion. In addition to this, as stated in the report, the privatization process of selling 5 power stations over the next 5 years by IEC to the private sector is ongoing. The sale of the first station was finalized at the end of 2019 for 1.9 billion shekels ($550 million).

The second station, which is double the size of the one sold, is at the time of writing this report under the process of being sold. As part of the privatization process, a new government grid management company will also be established, with an estimated start-up capital equity of 1 billion shekels ($288 million). On 1st January 2020, the government gave the green light to invest NIS 250 million ($72.4m.) in wind farm technologies to ensure that the construction of the wind turbine farms will not impact security considerations, and thus circumvent hurdles imposed by the security establishment.

Transportation

There are conflicting figures as to future investment and penetration of electric cars in Israel by 2030. These range from Israel Electric's estimate of 50,000 electric vehicles in use in 2030, the Ministry of Energy's figure of double this number and research firm BDO, predicting that Israel would have 300,000 electric vehicles in 2025 and 1.5 million in 2030. An important turning point will likely take place at the middle of the decade, when electric car prices balance out with the price gasoline-powered vehicles.

Research and Development

In December 2019, the U.S. Department of Energy (DOE) and Israel's Ministry of Energy along with the Israel Innovation Authority have selected seven clean energy projects to receive $6.4 million under the Binational Industrial Research and Development (BIRD) Energy program. The total value of the projects is $15.4 million, which includes $9 million of cost share from the companies selected for funding. The seven approved projects include a project to develop boosting EV charging through energy storage system, a project to optimize energy efficiency, technology for more efficient power supply for grid connected electronic devices, a study to develop a low cost and high efficiency solid biomass and solid waste fuelled electricity generation system.

Nuclear

No nuclear facilities are planned to be constructed.

KOSOVO*

* Throughout this Study, this designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.

Kosovo*

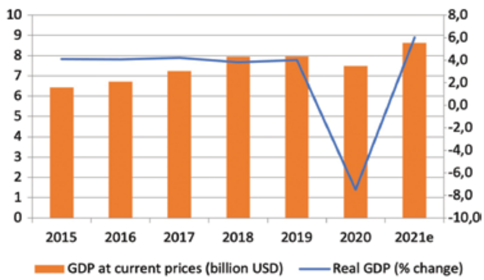
Economic and Political Background

Kosovo's GDP declined by about 4.14% in 2020, based on preliminary estimates the country's statistical office released on April 2, 2021. In the fourth quarter alone, GDP grew by 0.72% year-on-year. Measured at current prices, Kosovo's GDP totaled €1.9 billion in the October-December period.

The sectors with the highest positive contribution to Kosovo's economic growth in the fourth quarter of 2020 were mining and quarrying, manufacturing, electricity, water supply, information and communication, real estate activities, arts, entertainment and recreation and other services as well as public administration, education and health, professional and administrative activities.

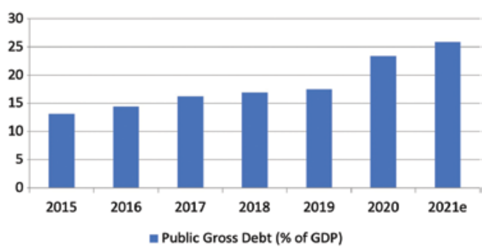
The government implemented the Economic Recovery Programme immediately after the outbreak of the pandemic, allocating €365 million of funds to support businesses, create jobs and stimulate aggregate demand. The Kosovo Assembly approved the additional fiscal stimulus of €200 million (or about 3% of GDP) for the Economic Recovery Programme in early December 2020. Public debt is expected to be 25.9% in 2021 and reach 28% in 2022. Inflation has slowed to 0.8 % in 2020, but is expected to rise to 1.2 % in 2021 and 1.7 % in 2022, according to the latest IMF World Economic Outlook (October 2020). Kosovo has come a long way since declaring its independence in 2008. It is recognised by more than 100 countries as an independent state, has established its first contractual agreement with the EU-the Stabilisation and Association Agreement-has its own international dialing code, and has become a member of several international organisations, amongst much else. Despite these achievements, however, its EU membership remains uncertain. Kosovo is still waiting for visa-liberalisation and the prospect of a final agreement with Serbia has waned.

Figure 5.165 **Kosovo's GDP and its annual GDP growth**



Source: IMF World Energy Outlook (October 2020)

Figure 5.166 **Kosovo's Public Gross Debt**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

The energy strategy of Kosovo 2017-2026 sets out the basic objectives of the Government of Kosovo in energy sector development, taking into account sustainable economic development, environmental protection, sustainable and reliable energy supply to final customers, efficient use of energy, development of new conventional and renewable generation capacities, creation of a competitive market, development of the gas system, and creation of new jobs in the energy sector. This energy strategy, based on a detailed energy sector analysis, has defined five strategic objectives:

1. Security of a sustainable, high-quality, safe, and reliable electricity supply with adequate capacities for stable power system operation;
2. Integration in the Regional Energy Market;
3. Enhancement of existing thermal system capacities and construction of new capacities;

* Throughout this Study, this designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.

4. Development of natural gas infrastructure;
5. Fulfillment of targets and obligations in energy efficiency, renewable energy sources, and environmental protection

Implementation of this «energy strategy» is of the utmost importance not only for sustainable, high quality, safe, and reliable energy supply in Kosovo, but for the overall economic development of the country, as well as for national security. In view of the various challenges faced in Kosovo's energy sector, it is crucial to have a strong contribution by all stakeholders, including the relevant international institutions, in order to achieve this target.

The key measures to achieve the strategy objectives are:

- Construction of new electricity generation capacities as replacement for the old ones in order to cover growing electricity demand and system reserve requirements, along with integration of the electricity market with that of Albania as a first step towards regional integration;
- Improvement of the operation of the distribution network by increasing efficiency and reducing costs;
- Fulfilment of the conditions for Kosovo's full integration in the common regional energy market and market opening obligations arising from the Energy Community Treaty and SAA;
- Expansion of the existing thermal power systems' capacities and preparation of the necessary conditions for the construction of new thermal systems;
- Preparation of the necessary conditions for natural gas infrastructure development;
- Improvement of overall energy efficiency and fulfilment of energy efficiency obligations arising from Kosovo's participation in the Energy Community Treaty and SAA;
- Greater use of other available energy sources, mainly renewable energy sources, as well as fulfilment of RES obligations from the Energy Community Treaty and SAA;
- Improvement of environmental conditions through the rehabilitation of Thermal Power Plant (TPP) Kosovo B and replacement of TPP Kosovo A with TPP Kosova e RE in line with Directive 2010/75/EC;
- Upon adoption of this Strategy, development of a set of supporting long-term energy sector development studies up to 2050 (as defined in new EU energy policy documents) according to the decarbonisation platform.

Governmental institutions

The Energy Regulatory Office (ERO) is an independent agency established by the Assembly of the Republic of Kosovo in accordance with Articles 119.5 and 142 of the Constitution of the Republic of Kosovo, responsible for economic regulation of energy sector. The duties and functions of ERO are set forth in the Law No. 05/L-084 on the Energy Regulator, among which are the following: creating and operating an efficient, transparent and non-discriminatory energy market; determining criteria and conditions for issuing licenses for the conduct of energy activities; determining criteria and requirements for granting authorizations for the construction of new generating capacities; monitoring and enhancing security of electricity supply; setting reasonable criteria and conditions for energy activities pursuant to tariff methodology.

Ministry of Economic Development (MED) is among others, responsible for energy sector strategy and policy (preparation and implementation), development of secondary legislation, renewable energy sources and rational use of energy, coordination of donors and attraction of investments; Independent Commission for Mines and Minerals (ICMM); is an independent agency pursuant to the Articles 119, paragraph 5, and 142 of the Constitution of the Republic of Kosovo.

ICMM regulates mining activities in Kosovo in accordance with the present law, the sub-normative acts issued pursuant to the Law on Mines and Minerals, and the Mining Strategy. Kosovo Competition Commission (KCC); was established by the Assembly of Kosovo based on the Competition Law no. 2004/36. Kosovo Competition Commission is an independent body and has responsibility for promoting competition among undertakers and protection of costumers in Kosovo.

Transmission System Operator (TSO) and Market Operator (MO)-KOSTT; was established on 1 July 2006, as a result of the restructuring of the energy sector and are responsible for planning, development, maintenance and operation of the electricity transmission system in Kosovo; ensuring an open and non-discriminatory access for third parties; functioning of the new electricity market; providing conditions that encourage competition in Kosovo; and cooperating with neighbouring Transmission System Operators (TSO). KOSTT operates as the Transmission System Operator (TSO) and Market Operator (MO).

Kosovo Energy Corporation J.S.C (KEK) is the electricity utility of Kosovo that covers coal mining and power generation that includes about 97% of electricity produced in the country.

Kosovo Electricity Distribution Company (KEDS): is a private company owned by the Consortium LimakÇalik that performs activities of electricity distribution, maintenance of medium and low voltage network, including metering devices.

Kosovo Electricity Supply Company (KESCO) J.S.C; is a company which was created in 2014, as a result of legal unbundling between distribution operator and supplier.

Kosovo Energy Efficiency Fund (KEEF) is an independent, autonomous and sustainable entity which was established through Law No. 06/L-079 on Energy Efficiency, to achieve the objectives of the Republic of Kosovo in the Energy Efficiency by promoting, supporting and implementing Energy Efficiency measures, as well as attracting and managing financial resources in order to finance and implement investment projects in the area of Energy Efficiency in a sustainable manner.

New Kosovo Electric Corporation (NKEC) J.S.C; is a Publicly Owned Enterprise, fully owned by the Government of Kosovo. NKEC was established as a Joint Stock Company in 2018 for the purpose of taking all electricity generated by the New Kosovo Power Plant (KRPP) based on the requirement deriving from the Agreement between Government of Kosovo and private investor. The KRPP Project Agreements includes the development, design, construction, financing, ownership, operation, and maintenance of KRPP Facility, and rehabilitation of the Site by the GenCo.

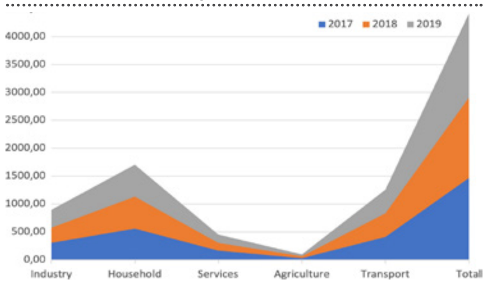
Energy Demand and Supply

Kosovo has the prerequisites for electricity production, not only to cover its own needs, but also to export it. Kosovo's power system is designed to produce lignite-based energy. Nonetheless, in spite of an increase in production in recent years, the domestic production is not sufficient to meet growing consumption and therefore part of Kosovo's electricity consumption is now covered by imports during different time periods especially in peak hours. However, in specific periods, mostly at night – where low tariffs of electricity apply- there is an excess of electricity which is exported.

National energy demand

In 2019, the total final consumption (TFC) reached 1.5 Mtoe, an increase of 15% compared to the 1.3 Mtoe consumed in 2013. The biggest share of consumption pertains to the household and transport sectors, with 575 Mtoe and 422 Mtoe, consumed respectively in 2019.

Figure 5.167 **Share of energy consumption (Ktoe) by economic sector and year**



Source: Kosovo Agency of Statistics – Energy Report 2020

National energy supply

In 2019, Kosovo's Total Primary Energy Supply (TPES) reached 2.7 Mtoe. This is an increase of 74% over the year 2000 when supply was 1.55 Mtoe. The dominant energy source is coal, accounting for 58% (1.55 Mtoe) of the country's TPEs in 2019, increased by 60% compared to 0.97 Mtoe in 2000. The available quantity of coal has increased by 13.84%, compared to 2018. There has also been an increase in the available quantity of oil products by 2.28%, compared to 2018.

Table 5.126 **Overview of primary energy supply in Kosovo (in ktoe)**

	2016	2017	2018	2019
Coal	1684,57	1447,85	1367,49	1556,38
Oil products	660,37	729,63	740,71	753,69
Biomass	368,50	365,16	370,16	361,03
Hydropower	18,36	15,34	28,84	22,26
Solar energy	0,39	0,42	0,44	1,34
Wind energy	0,06	0,05	2,56	7,80
Electrical energy	-43,63	-24,61	14,13	4,60
Total	**2688,62**	**2533,84**	**2524,32**	**2707,11**

Source: Kosovo Agency of Statistics

Energy balance

Based on the long-term energy balance for 2019-2028 approved by ERO, the following are the projections of GDP growth over the next 10 years that are in line with the «Energy Strategy», which were used to forecast the electricity demand.

Table 5.127 **Projections of GDP growth**

Annual growth [%]	2018	2019	2020-2028
GDP Low Growth Scenario	2.2%	2.2%	2.2%
GDP Base Growth Scenario	4.3%	4.3%	4.3%
GDP High Growth Scenario	5.4%	5.4%	5.4%

Source: Statement of Security of Supply for Kosovo

The basic demand scenario for electricity (BDS) foresees a slight increase in demand in the household sector, while it foresees a high increase in the services sector and the industrial sector.

Based on these forecasts, the energy demand (base scenario) in 2019 was forecasted to be 5,814 GWh, whereas in 2028 the demand is expected to reach 6,170 GWh[1].

The respective peak loads for these years are expected to be around 1,177 MW and 1,270 MW[2].

Energy mix

The structure of the primary energy consumed in Kosovo in 2019 consisted of coal, petroleum products (gasoline, diesel, fuel oil, kerosene and LPG), biomass, hydro, wind, solar and biofuels. Electricity is treated as a primary source just for the amount of import and export.

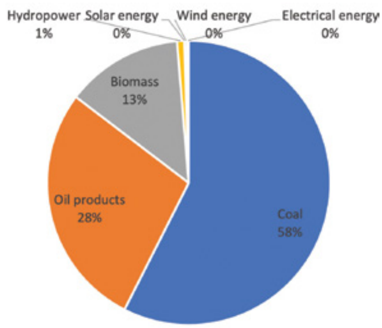
Lignite is the dominant product with a share of 99.97% in total coal, as the primary source available, followed by bituminous coal and other 0.03%. No oil is extracted in Kosovo, including refining raw crude oil, and therefore all oil needs are covered by imports. Imports of oil products in 2019 have been 753.69 ktoe and compared to 2018 there was an increase of about 2.28%. Benzine and Diesel oil account for about 66% of the total amount of oil products available; followed by oil coke, 12%; gasoline with 8%; GLN 4%; etc.[3].

The quantity of consumed firewood in 2019 was 361.03 ktoe. Compared to 2018 there was a decrease of about 2.43%. (Basic data on wood consumption for 2015 are taken from the survey on energy consumption by households).

The amount of hydropower produced in hydropower plants in 2019 was 22.426 ktoe, while the amount of wind-generated electricity was 7.8 ktoe. The amount of solar energy utilized in 2019 corresponded to 1.78 ktoe. According to a government survey, energy consumption in households reached 0.44 ktoe. In 2019 there was no evidence of any biofuel imports. Figure 5.168 shows the energy sources (in percentage terms) as a part of the total energy supply in Kosovo for the year 2019.

1 ERO - Statement of Security of Supply for Kosovo (Electricity, Natural Gas and Oil), 2019
2 Ibid.
3 Kosovo Agency of Statistics – Annual Energy Balance in the Republic of Kosovo in 2019

Figure 5.168 **Kosovo's energy supply**



Source: ERO Annual Report 2019

The Energy Market

Oil and Petroleum Products

(a) Oil supply and demand

Kosovo has neither domestic reserves of crude oil, nor the capacity for refining it and therefore does not import any crude oil. Kosovo is a net importer of petroleum products, and produces only heavy fuel oil for heating from imported raw materials amounting approximately to 30% of the consumption of heavy fuel oil for heating[4]. There are four licensed production plants, which currently produce heavy fuel oil with less than 1% of sulphur content. Heavy fuel oil with less than 1% sulphur content is produced by mixing heavy fuel oil containing over 1% sulphur with light oils such as gasoline and kerosene.

(b) Oil imports/dependence

Kosovo is a net importer of oil products. Since there are negligible amounts of domestic production and exports, almost all consumption within the country is covered by imports. In recent years the total imports of oil products did not have a significant upward trend, but only slight variations. In Table 5.128 and Figure 5.169 data is presented on consumption, import and export figures (negligible amounts).

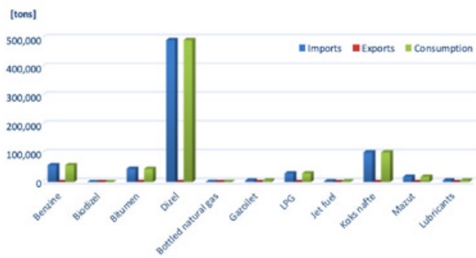
[4] ERO – Security of Supply Report 2019

Table 5.128 **Imports – Exports of petroleum products in Kosovo**

Petroleum Products - 2018 [in tons]			
Type	Imports	Exports	Consumption
Benzine	58,881.9	0	58,881.9
Biodizel	0.0	0	0.0
Bitumen	46,408.9	214.3	46,194.6
Dizel	494,247.6	0	494,247.6
Bottled natural gas	687.1	2	685.1
Gazoilet	5,506.4	0	5,506.4
LPG	30,537.1	0	30,537.1
Jet fuel	2,988.2	0	2,988.2
Koks nafte	103,954.9	0	103,954.9
Mazut	18,701.6	0	18,701.6
Lubricants	5,780.1	177.3	5,602.8
Total	767,693.8	393.6	767,300.2

Source: Kosovo Statistics Agency

Figure 5.169 **Petroleum products in Kosovo, 2018**



Source: Kosovo Statistics Agency

Kosovo is almost 100% dependent on imports of oil products with the majority of them originating from neighboring countries. The pattern of imported oil products in 2018 is presented in Table 5.129.

Table 5.129 **Origin of oil product imports in Kosovo, 2019**

ORIGIN OF OIL PRODUCTS IMPORTS [%]		
Country	Petroleum	Diesel
Albania	0.00%	17.90%
Bosnia & Hercegovina	0.00%	0.00%
Montenegro	0.00%	0.00%
Greece	56.28%	45.65%
Serbia	39.60%	20.62%
Macedonia	3.82%	15.70%
Croatia	0.30%	0.13%
Total	100%	100%

Source: ERO – Statement of Security of Supply for Kosovo 2019

Kosovo does not possess any pipelines for crude oil or for oil products transportation. Oil products are imported 75% by road transportation and 25% by railroad.

The law on trade with petroleum and petroleum products[5] obliges all companies dealing with petroleum and petroleum products to maintain storage facilities and sale points and to maintain reserves of at least 5% of their storage capacity at any time for emergency purposes. Currently licensed at storage tanks have approximately 80,000 m3 and approximately 40,000 m3 capacities for retail sale of fuels, while 5% of this capacity equals to 3-4 days of average daily net import. There is additional 50,000 m3 of storage capacity that is not being used and is not licensed for fuel storage. Currently there are 12 storage facilities that are licensed for fuel wholesale (diesel, petrol, LPG)[6].

Kosovo has an open market for oil products including imports and exports, and prices are set freely by the market. With regard to a 10% customs duty, this issue is addressed by the respective legislation in force, which fulfils obligations arising from international agreements (CEFTA, Energy Community Treaty) for the oil sector. More specifically, Law 04/L-163 and Administrative Instruction no.05/2015, amended by Administrative Instruction no.07/2016 for commodities, for which the customs duty isn't charged, specifies that oil products which are exempted from customs duty include: fuel oils, lubricants, bitumen, and calcinated and decalcinated petrol coke.

According to the Law on Trade with relevance to petroleum and petroleum products, the responsible authority for Kosovo's Oil sector is the Department for Regulation of the Oil Sector of Ministry of Trade and Industry. This department has the competences for licensing commercial entities and for undertaking the activities in the oil sector. Price regulation isn't implemented since the market is very competitive with over 40 importers for transport fuels and many other importers of other petroleum products. The wholesale and retail prices are freely set by market forces.

Security of supply[7]

Kosovo's electricity fulfills over 90% of demand from domestic generation, while as far as natural gas is concerned, it should be noted that there is no network developed, whereas all oil and oil products come from imports.

With respect to electricity, the sector is advancing regarding its generation capacities, transmission, distribution and supply of customers in general.
Since Kosovo's energy system is modelled for basic energy production, balancing the system remains one of the key issues. Energy required for the peak period, in addition to local production, is accomplished through imports, and in the case of the generating unit's failure is realized through emergency imports, or sometimes with the application of load shedding as the last measure to keep the system in balance.

Based on the Law on Energy, Article 25 *"the Government may, as an emergency measure, impose restrictions on energy supply for customers…".*

There have been investments in new network equipment as well as maintenance, but also in electricity generation, particularly regarding Renewable Energy Sources.

The transmission network is in good conditions, following the investments in the infrastructure. Kosovo's power transmission network meets the domestic transmission needs as well as the N-1 criterion, except for the Prizren 2 - Rahovec line, which remains in radial supply.
The important issues remain:

- The implementation of the agreement for connection of KOSTT at ENTSO-E;
- Commencement of commercial operation of the line 400kV Kosovo-Albania;
- The allocation of cross-border transmission capacities, which continues to be carried out by EMS and not by KOSTT as a legitimate owner.

[5] Law No. 03/L-138 on Amendment and Supplementation of Law No. 2004/5 on Trade of Petroleum and Petroleum Products in Kosovo
[6] ERO - Statement of Security of Supply for Kosovo (Electricity, Natural Gas and Oil). 2019.
[7] Ibid.

The distribution network still remains in unsatisfactory conditions and investments are required to ensure quality and sustainable supply for consumers.

Reduction of energy to customers due to energy shortages has decreased considerably. The current situation of electricity supply to costumers can be considered acceptable but in order to have better quality of electricity supply to customers, continuous investments are required, especially in the distribution network as well as in production. The issue of balancing the system remains problematic as there is insufficient generation capacity, especially flexible one, which could be activated in cases of power shortages or falls of a larger unit. Thus, in order to cover consumption during peak time, electricity imports are required, whereas for off-peak period, especially at night, there are electricity surpluses which could be exported.

With respect to natural gas, Kosovo does not have domestic natural gas production and is not connected to any natural gas supply operational network. Important issue remains:

- A connection to natural gas supply would be an important option for the introduction of natural gas in Kosovo;
- It is expected that following the finalization of the TAP project, Kosovo will be connected to the natural gas network through the ALKOGAP project, which is in study phase.
- As for oil sector it should be noted that Kosovo does not have sources of unrefined oil or capacities to carry out its processing, therefore Kosovo is a full importer of oil products.
- Currently there are 12 storage facilities which are licensed for wholesale (diesel, gasoline, LPG).
- Wholesale and retail prices are freely set from the market and there is a considerable competition.

Natural Gas

Kosovo has no domestic production of natural gas and it is not linked to any operational natural gas supply networks. A connection to natural gas supply would be an important option for the introduction of natural gas in Kosovo, which would impact diversification of fuel supply and help increase security of supply. Gas supply and consumption in Kosovo is therefore limited to bottled LPG (liquefied petroleum gas).

The official policy of the Kosovo Government is to promote and support the inclusion of Kosovo in the regional natural gas projects. The Trans Adriatic Pipeline (TAP) project could offer great opportunities to Kosovo to connect to the international natural gas network. In this regard, depending on the regional developments of gas projects in Southeastern Europe, the Government of Kosovo remains committed to use all opportunities to get involved in joint natural gas projects as coordinated by the Energy Community.

In order to create the prospect for the development of the natural gas sector and fulfillment of the obligations that Kosovo has as a full member in Energy Community Treaty, the Kosovo Assembly in June 2016, adopted Law no. 05/L-082 on Natural Gas, as part of the package of energy laws.

Following this Law, the transposition of the European third package legislation was carried out, which was relevant for natural gas, mainly:

- Directive No. 2009/73/EC concerning common rules for the internal market in natural gas; and
- Regulation No. 715/2009/EC on conditions for access to the natural gas transmission networks.

The law on natural gas lays out the foundation of the legal and regulatory framework for the transmission, distribution, storage and supply of natural gas and the operation of gas transmission and distribution systems. Consequently, this law determines the organization and functioning of the natural gas sector and access to networks and gas markets. Important interconnection projects between or within Member States – currently in the study phase is the project: ALKOGAP – Albania-Kosovo Gas Pipeline, which is regarded as a favorable option for the connection of Kosovo through Albania with TAP and respectively with the IAP Projects. This project is included in the List of Projects of Energy Community Interest ('PECI' List).

During 2018, the pre-feasibility study for the ALKOGAP project was prepared, and financed through the WBIF platform – EBRD being lead IFI for this project. The main objective of this study was to undertake an initial assessment on the feasibility for the construction of the ALKOGAP pipeline, as an option for supply with natural gas originating from the Caspian region. Connection is envisaged through the proposed regional TAP/IAP gas pipeline network connecting Albania and Kosovo in the first phase and potentially, in the future, to continue to other western Balkans countries. This study has included the following main components:

- A preliminary survey and determination of pipeline trench in Albania and Kosovo;
- Determination of the technical parameters of the pipeline and related stations and equipment, as well as pipeline hydraulic analysis and system configuration and optimization;
- Evaluation of the natural gas demand in Kosovo – namely: estimated consumption of the residential sector, services and industry, district heating including cogeneration of heat and electricity;
- Economic and financial analysis including estimation of the investment costs and O&M, and Cost benefit analysis; - Review and assessment of legal & regulatory and institutional framework, and elaboration of organization of natural gas market in Kosovo;
- Preliminary environmental and social impact assessment.

The pre-feasibility study has further recommended other project implementation phases, emphasizing the preparation of a Gas Master Plan for Kosovo and preparation of a Feasibility Study for this project, which would provide detailed assessment of feasibility and sustainability of the ALKOGAP project, as the main precondition for developing natural gas markets in Kosovo and Albania.

Map 5.47 **Regional gas infrastructure projects and options for the connection of Kosovo**

Source: ERO

The US MCC Programme ("Millennium Challenge Corporation") is carrying out a feasibility study exploring another entry to the gas market through North Macedonia. As part of its Energy Strategy for 2017-2026, Kosovo is also aiming to establish a Gas Transport System Operator and Gas Distribution Operator and invest in natural gas infrastructure[8].

Solid Fuels

Kosovo has large reserves of lignite which ensure long-term electricity generation. However, the problem is the impact on the environment due to emission of greenhouse gas and other polluters. Around 89.23% of Kosovo's installed electricity generation capacities involves power plants that operate with lignite as the primary source of supply[9]. Lignite production in 2018 was 7.17 mton, whereas consumption reached 7.48 mton, with these quantities being smaller compared to 2017. Production and consumption of lignite on a monthly basis, for 2018, is presented in Table 5.130. Concerning imports of solid fuels, it must be clarified that there are not any import of coal or lignite.

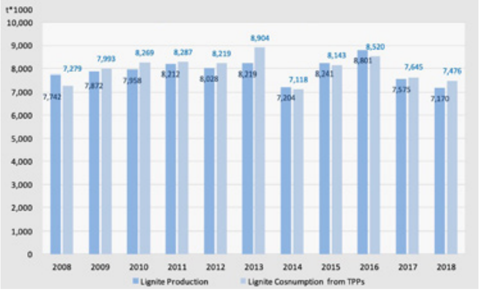
Table 5.130 **Production and Consumption of Lignite in 2018**

Lignite Generation/Production	Totali	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Lignite Production (t*1000)	7,170	648	606	727	636	451	549	421	647	558	692	632	605
Lignite Consumption (t*1000)	7,476	590	688	823	642	713	502	559	557	517	612	538	736
Lignite Consumption in the Market	117	0	0	0	0	8	7	3	14	27	26	16	16

Source: ERO Annual Report 2018

[8] MED – Energy Strategy of the Republic of Kosovo 2017-2026
[9] ERO Annual Report 2018

Figure 5.170 **Production and consumption of lignite, 2008 – 2018 (in mt)**



Source: ERO Annual Report 2018

Table 5.131 **Coverage of energy demand with lignite by economic sector (in ktoe)**

	2016	2017	2018	2019
Industry	26,03	16,71	6,40	10,48
Household	8,70	7,44	2,50	2,51
Agriculture	1,12	0,69	0,69	0,83
Services	64,00	37,20	8,35	7,61
Final energy consumption	99,86	62,04	17,94	21,43
Available for final consumption	99,86	62,03	23,39	28,97
Statistical difference	0,01	-0,01	5,45	7,54
Coverage of lignite demand by sector (ktoe)				

Source: Kosovo Agency of Statistics (2019)

Electricity

(a) Electricity supply and demand

Kosovo possesses the prerequisites for electricity generation not only to meet local demand but also for export. The electrical power system is mainly designed to generate electricity from conventional lignite sources, therefore maximum load coverage and system balancing remain a major challenge for all stakeholders[10]. Although lignite-generating units that are in operation are very old, over the last few years there has been an increase in electricity production. However, domestic power generation is not sufficient to cover the continuous increase of consumption, hence, part of the electricity consumption in Kosovo is covered by imports over different time periods, especially at peak times. Despite this at certain times, especially during the night (at low tariff period), there are surpluses of electricity that are exported.

The electricity generation capacity in Kosovo is dominated by lignite fired plants Kosovo A and Kosovo B. These two power plants together have an installed total capacity of 1,478 MW. Due to aging and the non-operation of two Kosovo A units, the available capacity of the two TPPs is much lower than the installed capacity. Together, the total available capacity of these units is about 960 MW. Currently, generation of electricity from these power plants covers almost 94% of total generation in Kosovo[11]. In addition, TPP-s, generation is also supported by hydro power plants: HPP Ujmani with an installed capacity of 35 MW, the cascade of Lumbardhi River with a capacity of about 26 MW. In addition there is the AirEnergy – KITKA wind farm with a capacity of about 32.4 MW, as well as some small power plants connected to the distribution system with an overall installed capacity of 25.19 MW.

Table 5.132 shows the installed electricity capacity of Kosovo per plant at operating unit.

Table 5.132 **Installed electricity capacity in Kosovo**

Generator units	Units capacity (MW)			Entry into operation	Life expectancy
	Installed	Net	Min/max		
A3	200	144	100-130	1970	2017
A4	200	144	100-130	1974	2017
A5	210	144	100-135	1975	2017
TPP Kosova A	**610**	**432**			
B1	339	264	180-260	1983	2030
B2	339	264	180-260	1984	2030
TPP Kosova B	**678**	**528**			
HPP Ujmani	35.00	32.00		1983	>2030
HPP Lumbardhi	8.08	8.00		(1957) 2006	>2030
HPP Dikanci	4.02	3.34		(1957) 2013	>2030
HPP Radavci	1.00	0.90		(1934) 2010	>2030
HPP Burimi	0.95	0.85		(1948) 2011	>2030
EGU Belaja	8.06	7.50		2,016	>2030
EGU Deçani	9.81	9.50		2016	>2030
HPP Hydroline-Albaniku III	4.27	4.27		2,016	>2030
HPP Brod II	4.80	4.80		2015	>2030
HPP Restelica 1&2	2.28	2.28		2,016	>2030
HPP Brezovica	2.10	2.10		2017	>2030
Wind Power	1.35	1.35		2,010	>2030
Air Energy-Kitka	32.40	32.40		2018	>2030
PV LedLight Technology	0.10	0.10		2,015	>2030
PV ONIX SPA	0.50	0.50		2016	>2030
PV Birra Peja	3.00	3.00		2,018	>2030
PV Frigo Food Kosova	3.00	3.00		2018	>2030
Total	**1,408.72**	**1,075.90**			

Source: ERO Annual Report 2018

Electricity generation in Kosovo has increased over the years. Figure 5.171 shows the overall generation in Kosovo during 2008-2018, where we notice a continuous increase until 2018, with a slight decrease of electricity production in 2014 and 2017.

[10] ERO – Annual Report 2019
[11] ERO – Annual Report 2019

5

The annual generation of electricity in TPPs is planned in line with optimum utilization of generation capacities. Electricity provided at the entry of transmission at TPP Kosova A and TPP Kosova B is planned for **4,495** GWh, where:

- TPP Kosova A = **1,956.7** GWh, at the entry of transmission.
- TPP Kosova B = **2,538.2** GWh, at the entry of transmission.

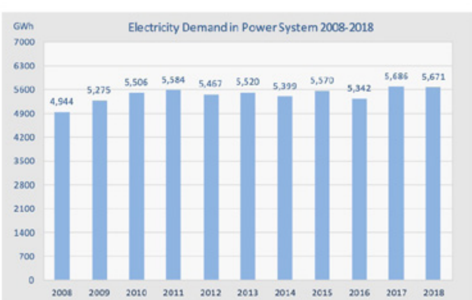
Whereas, the entire national generation, including HPPs connected to the distribution network including wind generators as well as solar panels is planned for an amount of **5,051.1**GWh[12].

Figure 5.171 **Electricity generation in Kosovo (2008-2018)**

Source: ERO Annual Report 2018

The overall electricity demand in Kosovo for 2020, including the supply for consumption in North of Kosovo, is estimated at 6,404 GWh. Fig. 5.172 includes only data until 2018, which shows that there has been an increase of 12% in consumption since 2018.

Figure 5.172 **Electricity Demand in Kosovo's Power System (2008-2018)**



Source: ERO Annual Report 2018

Electricity demand for 2017 was 5,686 GWh, while peak load during winter was 1,161 MW, whereas in 2018 total demand was 5,671 GWh, and peak load during winter reached 1,203 MW.

As stated above, electricity production in most of the years has been lower than the overall demand, but generation has increased at the same time as demand, as presented in Figure 5.173, which shows the balance between electricity generation and demand for 2000-2018.

Figure 5.173 **Balance between total production and gross consumption (200-2018)**

Source: ERO Annual Report 2018

Throughout the years 2000-2018 the overall demand for electricity has increased by an average of about 5.56% per year. During this period the generation units did not cover the electricity demand, which as a result was offset by the import of electricity (except in the years 2013 and 2016 when the generation exceeded the demand, and Kosovo was a net exporter of electricity). The figure above shows the level of net imports, which are used to supply electricity customers. The import towards total demand in the period 2000 - 2018 was 13.8% in the Republic of Kosovo[13] .

(b) Planned new capacity – investments

In recent years, some investments have been made in order to upgrade the electricity system. Such investments provided a safer and qualitative supply to customers. They have increased the security of supply and have resulted in considerable decrease of losses. Kosovo B power plant units will soon reach the end of their forecasted lifespan, so investments and significant rehabilitation measures are planned to be implemented during 2023/2024, in order to adjust these two units to the standards

[12] ERO – Annual Report 2018
[13] ERO - Statement of Security of Supply for Kosovo (Electricity, Natural Gas and Oil), 2019

required for operation, thereby achieving the required level of environmental standards and extending their lifespan beyond 2039.According to the «Energy Strategy», investments in new generation capacity are required in order to safeguard security of energy supply. In this regard, the government of Kosovo has carried out an open and competitive tender, in which case an investor was selected for the construction for a new thermal generating plant, using lignite, with a capacity of 450 MW. In order to facilitate the market integration of the new plant, the Government has established the New Kosovo Electricity Company ('NKEC') to take over the risk of purchasing the generated electricity. The energy purchased by NKEC shall be traded in a transparent, non-discriminatory and market-based market, in accordance with Kosovo's laws and applicable competition rules, including the requirements of the Energy Community. The forecast for electricity generation for the period 2019-2028 is based on electricity generation from the following: TPP Kosovo A, TPP Kosova B, HPP Ujmani, HPPs in Lumbardhi, the KITKA wind power plant, small existing hydropower plants, other renewable energy sources, the power plant Kosova e Re, as well as flexible HPPs. Table 5.133 shows the new generation capacity over the coming years.

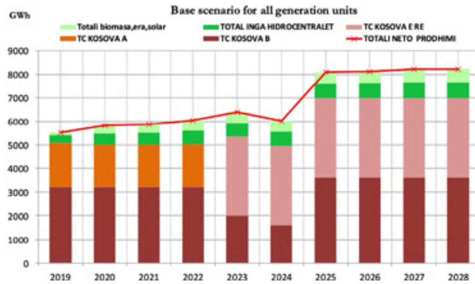
Table 5.133 **New generation capacity in Kosovo**

		Install capacity	In operation	Life
New TPP's	TPP New Kosova			
	G1	P=450 MW	2023	>2050
	TPP Fleksibile			
	G1	P=200 MW	2023	>2050
Renewable Energy Sources	Small HPP			
		P_{2028}=101 MW	2019 - 2028	>2050
	Wind turbines			
		P_{2028}=180 MW	2019 - 2028	2035 - 2045
	Biomass			
		P_{2028}=16 MW	2019 - 2028	>2050
	Solar			
		P_{2028}=85 MW	2019 - 2028	2035 - 2045

Source: The data is taken from the KOSTT document Long-term Balance Sheet 2019 - 2028 approved by ERO

Figure 5.174 presents a forecast of electricity generation in Kosovo until 2028.

Figure 5.174 **Anticipated electricity generation in Kosovo (2019-2028)**



Source: The data is taken from the KOSTT document Long-term Balance Sheet 2019 - 2028 approved by ERO.

(c) Electricity imports - exports

Kosovo's electricity demand is covered by domestic generation and imports realized through cross-border transmission lines. The country's total electricity demand was covered by imports at the level of 14.55%, which represents a decrease of about 7.3 percentage points from the previous year, being about 21.85%. In 2019 2,683,390 MWh entered the country through Kosovo's international electricity interconnections, while 2,322,325 MWh were actually delivered, of which 361,063 MWh for internal consumption, while the rest was in transit. Table 5.134 shows the electricity flows through electricity interconnection lines with neighbouring countries.

The net imports realized in 2018 were 928,492 MWh, with which the energy deficiencies were met, especially at peak times in winter season when demand could not be met only with domestic generation.

Table 5.134 **Electricity flows through Kosovo**

Interconnection flow MWh	400 kV Received	400 kV Delivered	220 kV Received	220 kV Delivered	110 kV Received	110 kV Delivered	Total Received	Total Delivered
Albania			279,079	195,874			279,079	195,874
N. Macedonia	84,457	1,400,701					84,457	1,400,701
Montenegro	600,799	362,143					600,799	362,143
Serbia	1,390,934	59,663	108,958	61,211	16,902	117,563	1,516,795	1238,436
Total	**2,076,191**	**1,822,506**	**388,038**	**257,085**	**16,902**	**117,563**	**2,481,130**	**2,197,154**

Source: ERO Annual Report 2018

5

This amount included electricity imported for both regulated and unregulated customers, the losses in the transmission network and the losses in the distribution network, which is provided through commercial contracts and through the exchange of energy between KEK and KESH. Total electricity imports for 2019 was 13 percent higher than in 2018, which was 825,182 MWh.

Electricity imported through commercial contracts during 2019 was 894,062MWh and corresponded to 50,132,368 € with an average price of 56.07 €/MWh. Although in HUPX the average price of 2019 compared to the average price of 2018 was lower by only 0.64 € / MWh, in Kosovo compared to last year, the average import price was lower by 10.27 € / MWh. Figure 5.175 shows the net electricity import and export of Kosovo.

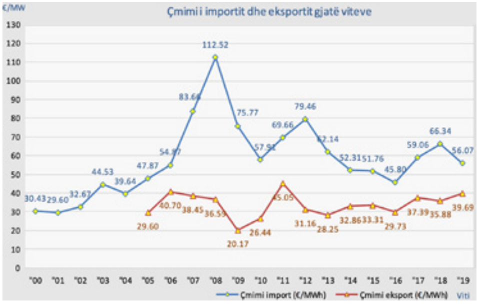
The Energy Regulatory Office mentions that considering the curve line of consumption and non-flexibility of generation units in addition to the lack of electricity, there is often excess in the system, and, in many cases, this occurs on the same day. Therefore, on a single day, and in certain hours, electricity is imported, while in others, there is electricity excess, which must be exported.

Figure 5.175 **Net electricity import and export in Kosovo**

Source: ERO Annual Report 2019

There has been an increase and decrease of electricity prices for imports and exports through the years 2000 – 2019. Figure 5.176 shows the import and export prices between 2000 and 2019.

Figure 5.176 **Import and export electricity prices in Kosovo, 2000-2018**



Source: ERO Annual Report 2019

(d) Tariffs

ERO has jurisdiction for setting tariffs for all energy services. The regulated retail tariffs, applied as from April 2020, for the regulated customers, are shown in Table 5.135.

Table 5.135 **Regulated retail prices in Kosovo, 2020**

Tariffs	Voltage Level of supply	Tariff elements	Unit	Time of day	Approved 2020 1
1	35 kV	Standing (customer) charge	€/customer/month		11.19
		Power engaged	€/kW		5.85
		Active energy (P)	€c/kWh	High tariff	4.92
		Reactive energy (Q)	€c/kWh	Low tariff	3.16
			€c/KVArh		0.67
2	10kV	Standing (customer) charge	€/customer/month		4.62
		Power engaged	€/kW		5.04
		Active energy (P)	€c/kWh	High tariff	5.73
			€c/kWh	Low tariff	3.69
		Reactive energy (Q)	€c/KVArh		0.67
3	0.4 kV Category I	Standing (customer) charge	€/customer/month		2.57
		Power engaged	€/kW		2.97
		Active energy (P)	€c/kWh	High tariff	6.69
			€c/kWh	Low tariff	4.96
		Reactive energy (Q)	€c/KVArh		0.67
4	0.4kV Category II	Standing (customer) charge	€/customer/month		2.97
		Active energy (P)	€/kW	Single tariff	8.83
		Active energy (P)	€c/kWh	High tariff	10.71
			€c/kWh	Low tariff	5.30
5	0.4KV Domestic 2-rate meter	Standing (customer) charge	€/customer/month		1.74
		Active energy (P)	€c/kWh	High tariff	6.75
			€c/kWh	Low tariff	2.89
6	0.4 kV Domestic 1-rate meter	Standing (customer) charge	€/customer/month		1.74
		Active energy (P)	€/kW		5.32
7	0.4 kV (domestic unmetered)	Estimated consumption			
		Standing (customer) charge	€/customer/month		1.74
		Active energy (P)	€/kW		6.75
8	Public lighting	Standing (customer) charge	€/customer/month		3.21
		Active energy (P)	€/kW		9.24

Note: Tariff applies 07:00-22:00 Monday-Saturday during the High Season (1 October – 31 March) and 08:00-23:00 Monday-Saturday during the Low
Season (1 April – 30 September)
Customers are charged reactive energy over allowed, corresponding with cos(Φ)=0.95.
Source: ERO Decision 149/20

(e) Cross-border interconnections

Electricity transmission is of particular importance for security of supply and for the operation of the entire power system of the country. Kosovo's Transmission network represents an important regional node which is interconnected with the European power system.

There are interconnection lines with neighboring countries as follows:

- Albania, North Macedonia, Montenegro, and Serbia - line 400 kV,
- Albania and Serbia - line 220 kV and
- Serbia - two lines 110 kV

Interconnection line 400 kV SS Kosova B - SS Kashar (Tirana) was completed in 2016 and carried out successfully testing, but for political reasons this has not yet become fully operational.

Renewables

(a) Overview of sector's development

Kosovo has a significant potential for expanding the use of renewable energy sources (RES) for electricity generation. The biggest potential sources are wind, hydro and biogas, while solar, geothermal and biomass have lower development potential. The issue of RES is relatively new in Kosovo, taking into account that over 90% of electricity generation is based on thermal power plants. Currently, hydro and biomass, in the form of wood, are the only types of RES used, which contribute significantly to Kosovo's energy supply. The use of solar energy is still at an early stage.

(b) Latest legislation, incentives and national RES policy

Policies in support of RES are based on Energy Law Nr. 05/L-081, which aims to promote the sustainable and economic use of RES and exploit its domestic potential, in order to meet rising energy demand, increase security of supply and ensure environmental protection which is an integral part of the «Energy Strategy» of the Republic of Kosovo.

In order to implement RES policies, the respective Ministry has determined the RES targets for energy, according to the legislation in force, in line with the requirements of the relevant European Union Directive for RES.

The Law concerning the Energy Regulator no. 05/L-084 stipulates that construction of new RES capacity and of new systems for the transmission and distribution of natural gas, including interconnectors, as well as direct electricity lines and direct gas pipelines for the transfer of natural gas will be made in accordance with the authorization procedure under this law, which shall be undertaken by the Energy Regulatory Office, in accordance with objective, transparent and nondiscriminatory criteria.

In order to abide with the legal obligations for meeting the obligatory RES target by 2020, the Ministry of Economic Development has issued Administrative Instructions no. 01/2013 and no. 05/2017 which set the annual and long-term energy targets of energy from RES. These Administrative Instructions have stipulated that the mandatory target for Renewable Energy Sources is 25% of the final gross energy consumption by 2020, as defined in Article 4 of the Decision of the Ministerial Council of the Energy Community Nr. D/2012/04 / MC-EnC.

Kosovo has agreed to a binding RES target of 25 % of its gross final energy consumption by 2020 and a voluntary RES target of 29.47 % . In breaking down the total obligatory target of 25% in gross final energy consumption coming from RES, 14.33% of RES is projected for electricity; 10% of RES for transport and 45.65 % RES for the cooling and heating of buildings. Table 5.136 presents the projected development of RES targets starting from 2009 until 2020, for both mandatory and voluntary targets, for each sector.

Table 5.136 **RES Electricity Capacity in Kosovo (2016-2020)**

Capacity of Electricity from RES					
Primary Energy Source	2016	2017	2018	2019	2020
Photovoltaic	6	7	8	9	30
Wind	1	61	115	129	150
Small HPPs	40	57	181	187	240
Biomass	6	8	10	12	20

Source: ERO Annual Report 2019

Currently the government is in the process of assessing RES integration achievements and setting new targets for the following period. It is expected that Kosovo will further promote RES, in line with potential, obligations and needs, as well as European developments and experience. As an Energy Community contracting party, Kosovo has an obligation to implement European Directives related to the environment and this will remain one of the strategic objectives of the Kosovo energy sector.

In Kosovo, investments in renewable sources are supported through Feed-In Tariffs (FIT). Feed-in Tariffs applicable for electricity generated from Renewable Energy Sources and admitted in the Support Scheme vary for the different technologies as shown in Table 5.137:

Table 5.137 **Applicable Feed-in Tariffs for RES in Kosovo (2019)**

Level of Feed-in Tariffs applicable for RES	
Primary Renewable Energy Source	[€/MWh]
Photovoltaic Energy	136.4
Wind	85.0
New small hydro power plants	67.47
Biomass	71.30

Source: ERO

Feed-in Tariffs are applicable to all applicants, who have been issued electricity production licenses in accordance with Decision on Notification for Preliminary Authorization and Final Authorization, as admitted to ERO's Support Scheme and who have signed the Power Purchase Agreements with MO.

Regarding the promotion of electricity generation from renewable energy sources, Article 14 of Law no. 05/L-081 on Energy requires all participants in the energy sector to perform the following tasks:

(a) When dispatching the generated electricity, the Transmission System Operator, or the Distribution System Operator, shall give priority to electricity generated from renewable energy sources, subject to the restrictions specified for purposes of system security by the Grid Code and other regulation and codes.

(b) The Transmission System Operator and Distribution System Operator shall establish and publish standard rules on who bears the costs of technical determinations, such as grid connections and their grid reinforcements, necessary to integrate new electricity producers supplying electricity produced from renewable energy sources into the interconnected system. Such rules shall be submitted for approval to the Regulator and should be consistent with the Strategy, based on objective, transparent and non-discriminatory criteria.

The Rule on Support Scheme for RES which is being implemented since 2017, defines the regulated mechanisms for supporting electricity generated from renewable energy sources.

Among others this regulation sets:

- The principles of supporting RES Generating Facilities admitted to the Support Scheme;
- The eligibility criteria for admission to the RES Support Scheme;
- The application procedure for admission to the RES Support Scheme;
- The procedure for funding the RES Support Scheme;
- The principles of supporting RES Generating Facilities, in accordance with the Regulated Framework;
- The principles of supporting RES self-consumption generators.

According to the Rule on Support Scheme for RES, all generating units which have been admitted to the Support Scheme have the right to sell their electricity output to the Market Operator through a Power Purchase Agreement for a period of 10 to 12 years, depending on the technology, and with a Feed-in Tariff price. PPA with Market Operator shall be concluded within thirty (30) days following the admission to the Support Scheme.

The achievement of annual RES energy targets was envisaged to be fulfilled in accordance with the penetration of specific RES technologies in electricity generation (RES-E), in heating and cooling production (RES-H) and in the transportation sector (RES-T). To this end, three different sub-targets were introduced so as to facilitate the achievement of the RES energy targets for 2020

These three sub-targets in the 2013 version of the NREAP were as follows:

- 25.64% penetration of RES in the gross final electricity consumption, to be achieved by the installation of small hydropower plants (240 MWe), Zhuri hydropower plant 305 MWe), wind plants (150 MWe), biomass plants (14 MWe) and photovoltaic plants (10 MWe).
- 10% penetration of RES in the final consumption in transport, must be achieved through the deployment of biofuels.
- 45.65% penetration of RES in the final consumption for heating and cooling, to be achieved through the promotion of solar energy (70 MWth), geothermal heat pumps (10 MWth) and biomass in the form of traditional logwood.

Table 5.138 shows the progress of RES penetration compared to the targets set for 2020.

Table 5.138 **Progress towards the fulfilment of RES targets in Kosovo**

	2009	2010	2015	2016	2017	2018	2019	2020
RES-E numerator (ktoe)	5.3	6.5	9.9	28.7	28.7	46.9	59.1	91.4
RES-H&C numerator (ktoe)	234.9	236.6	263.8	263.8	263.8	272.7	281.7	303.6
RES-T numerator (ktoe)	0.0	0.0	0.0	0.0	0.0	7.7	19.5	39.7
Total RES numerator (ktoe)	240.3	243.1	273.6	292.4	292.4	327.3	360.4	434.6
GFCoE adjusted (ktoe)	1354.3	1379.3	1522.7	1,557.0	1,592.0	1,629.0	1,694.8	1,735.9
RES-E denominator (ktoe)	470.3	484.4	537.4	548.4	563.3	574.8	612.6	625.5
RES-H&C denominator (ktoe)	528.9	565.3	606.7	622.8	634.7	650.7	666.6	683.2
RES-T denominator (ktoe)	325.6	304.0	366.7	373.8	376.9	383.7	390.3	396.9
RES-E [%]	1.1%	1.3%	1.8%	5.2%	5.1%	8.2%	9.7%	14.6%
RES-H&C [%]	44.4%	41.8%	43.5%	42.4%	41.6%	41.9%	42.3%	44.4%
RES-T [%]	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	5.0%	10.0%
RES-Total [%]	17.7%	17.6%	18.5%	18.8%	18.4%	20.1%	21.3%	25.0%

Source: NREAP – Update for 2018-2020

(c) Installed capacity per source (in MW)

Data on currently installed capacities per type of RES and relevant electricity generation (GWh) from RES is summarized in Table 5.139.

Table 5.139 **Summary of RES technologies as applied in Kosovo**

	RES Type	Installed capacity [MW]	Electricity generation [GWh]	Notes
1.	Wind onshore	33.75	29.783	The capacity of 32 MW started operation on October 11, 2018
2.	Wind offshore	/	/	
3.	Solar PV	6.6	1.938	The capacity of 6 MW started operation on November 6, 2018
4.	Solar thermal	/	/	
5.	Hydro			
5.a	Small hydro	45.37	173.447	
5.b	Large hydro with reservoir or run-of-river			
6.	Biomass	/	/	
6.a	Bio-solids			
6.b	Biogas			
6.c	Waste			
7.	Geothermal	/	/	

Source: ERO Annual Report

(d) Planned new major projects

RES investment projects are expected to increase in the following years. Based on the Register of Applications for the Construction of New Generating Capacities and Admission to Support Scheme from RES, as published on ERO's website, RES investment projects which are expected to be implemented over the next few years are summarized in Table 5.140:

Table 5.140 **Status of RES projects in Kosovo under different stages of the Licensing Process (Status 2019)**

	Final Authorization		Preliminary Authorization		Pending applications for admission to Support Scheme	
	#	Capacity (MW)	#	Capacity (MW)	#	Capacity (MW)
Hydro	16	57.5	1	3.3	/	/
Wind	3	103.5	1	11	7	235.1
Solar	1	3	/	/	35	102.3
Biomass	/	/	1	1.2	/	/
Total	20	164	3	15.5	42	337.4

Source: Register of Applications for the Construction of New Generating Capacities and Admission to Support Scheme from RES

Energy Efficiency and Cogeneration

(a) National targets

Along with the need and efforts to ensure sufficient energy generation from existing power plants and other alternative sources, energy efficiency in Kosovo is considered by the GoK an essential component of strategic planning and economic development. The Ministry of Economic Development is the lead Ministry with oversight of the energy sector, energy efficiency policy planning and monitoring of implementation.

Table 5.141 shows Kosovo's targets for Energy Efficiency, as defined by Long-term NEEAP 2010-2018, Long-term Energy Balance of the Republic of Kosovo 2015-2024 and NEEAP 2019-2021.

Important political, legal, and institutional steps have already been taken in energy efficiency promotion. Law No.06/L –079 on Energy Efficiency which transposes the Directive 2012/27/EU, was adopted on 07.11.2018. Secondary legislation is under finalization by MED.

Table 5.141 **Kosovo's energy efficiency targets**

TARGETS	2017	2018	2019	2020
EED ARTICLE 3 [ktoe]		*91.89*		*113.09*
EED ARTICLE 5 [ktoe]		*0.12**	*0.24**	*0.36**
EED ARTICLE 7 [ktoe]	*4.6*	*9.1*	*15.5*	*21.9*
PEC [ktoe]		*2719***		*2847***
FEC [ktoe]		*1486*		*1556*
FEC - BUILDINGS [ktoe]		*685*		*711*
FEC - INDUSTRY [ktoe]		*401*		*425*
FEC - TRANSPORT [ktoe]		*365*		*382*
FEC – OTHERS [ktoe]		*35*		*38*
PRIMARY ENERGY INTENSITY [ktoe/mil.EUR]				
FINAL ENERGY INTENSITY [ktoe/mil.EUR]				

Source: Energy Community – Kosovo Annual Report 2019

5

In order to implement the requirements of Law No. 05/L-101 on Energy Performance of Buildings, which transposes Directive 2010/30/EU, the following regulations were introduced:

- Regulation (MESP) No.02/18 on National Calculation Methodology for Integrated Energy Performance of Buildings adopted on 07.12.2018.
- Regulation MESP No.03/18 of The Procedures on Energy Performance Certification of Building adopted on 10.12.2018.
- Regulation MESP No.04/18 for Minimum Requirements for The Energy Performance of Buildings adopted on 13.12.2018.
- Regulation MESP No. 01/2018 for Inspection of Heating and Air-Conditioning System adopted on 16.02.2018.

(b) Incentive-based initiatives in the building sector

Regarding latest developments, Energy Community mentions that Kosovo has prepared laws on energy efficiency for buildings, which include provisions on certification of buildings, minimum energy performance standards, heating and cooling systems inspections, etc.

In addition to transposing EED, the new Law on Energy Efficiency also laid the ground for the establishment of the first financial mechanism for Energy Efficiency, Kosovo Energy Efficiency Fund (KEEF). KEEF was established in 2019, which made Kosovo the first country in the Western Balkans to launch an Energy Efficiency Fund. KEED will play an important role in financing energy efficiency measures in public institutions such as municipalities and ministries.

Municipal Energy Efficiency Action Plans have been drafted, paving the way for the municipalities to apply for the KEEF in order to implement EE measures and reduce energy consumption

(c) EU funded energy efficiency programmes in the building sector

- In 2019 Kosovo became the first country in the Western Balkans to launch an Energy Efficiency Fund. The Energy Efficiency Fund was launched by the Ministry of Economic Development with the support of the World Bank and the European Union. This fund was created as a result of the adoption of the Law on Energy Efficiency in November 2018. For this fund the Kosovo Government has allocated € 1 million, while World Bank and EU pledged € 10 million .
- During 2018 two renovation contracts were completed by Kosovo Energy Efficiency and Renewable Energy Project (KEEREP) financed by the WB - the contract for package 2 (12 buildings) was finalized by end of March, while package 3 (20 buildings) was finalized by early December of 2018. With the implementation of these two renovation contracts, based on energy audit reports data, substantial energy savings were achieved of approximately 51% on an annual basis, or 13,2390 MWh/a compared to baseline energy, while annual government cost saving in amount of 1.23 mill euro. Around 2.2 MW RES capacity was installed for heating and SHW, whereas the CO_2 savings were of approximately 4700 ton/year.
- MED has implemented energy efficiency measures in 20 schools in 2018 under state budget financing with a total amount of 1.5 mill euro.
- The EBRD Green Economy Financing Facility (GEFF) has been operational in Kosovo since 2018. GEFF provides finance for green economy investments in the residential sector as well as to businesses that provide energy efficiency and renewable energy products and services to households.

(d) Cogeneration: Regulatory framework, installed capacity

Cogeneration in Kosovo is not highly developed. Table 5.142 depicts the current district heating companies with special reference to the Termokos and Gjakova District Heating Systems. Also, the low level of industrial and economic development in Kosovo creates unfavorable conditions for the development of industrial cogeneration.

The Termokos and Gjakova District Heating Systems in Pristina and Gjakova respectively consist of three major activities: heating generation, distribution and supply. Both companies are licensed by the ERO for performing the aforementioned activities. Both state-owned companies are supervised by the Municipalities of Pristina and Gjakova respectively.

Table 5.142 **District Heating Capacity in Kosovo**

Company (City)	Installed Capacity [MW]	Operational Capacity [MW]	Thermal Energy Network	
			Length of the Network (track)	No. of substations
TERMOKOS (Pristina)	2 x 58 = 116	2 x 49.3 = 98.6	Distribution	
	2 x 7 = 14	2 x 6.3 = 12.6	39.0	437
	1 x 4 = 4	3.6	Transmission	(active-425)
	[Kogjenerimi] 2 x 70 = 140	2 x 68.7 = 137.4	10.5	
Sub-total	274.0	252.2	49.5	437
DH GJAKOVA (Gjakova)	1 x 20 = 20	1 x 14.8 = 14.8	Distribtuion	302
	1 x 18.6 = 18.60	1x13.02 = 13.02	13.5	(active-180)
Sub-total	38.6	27.8	13.5	302
Total	312.6	280.0	63.0	739

Source: ERO Annual Report 2018

Throughout the years several investments have been implemented, including the rehabilitation of generation equipment, replacement of the old network of thermal conductors, expansion of the heating network and expansion of heated areas.

Termokos relies on the generation of thermal energy in Co-generation plants in TPP Kosova B; in fact during the 2018/2019 heating season, the entire generation of thermal energy was from cogeneration plants in TPP Kosova B, and so it was not necessary to activate the heavy fuel oil boilers in Termokos Heating. The amount of thermal energy extracted from cogeneration in the 2018/2019 season was 235,079 MWhTH. While the amount of thermal energy received at the heat exchange station in DH Termokos was 229,661 MWhTH, which also represented an increase of 9,90 MWhTH or 4.41% compared to last season (219,954 MWhTH).

Table 5.143 presents the summary data on generation, supply and losses for the entire thermal energy sector.

(e) Planned new major projects

Following ratification of the agreement of 15 January 2015 between the Republic of Kosovo (Recipient) and the International Development Association (IDA), worth of USD 31 million and based on the successful implementation of the Energy Efficiency and Renewable Energy Project for Kosovo (EEREPK), the Ministry of Economy and Environment expressed, through the Kosovo Agency for Energy Efficiency, its readiness to implement the final package worth € 5 million targeting municipalities through the Kosovo Energy Efficiency Fund under this agreement.

Table 5.143 **Energy Performance of Thermal Energy Sector– season 2018/2019**

Thermal Energy Sector – Season 2018/2019				
Description	Unit	DH Termokos	DH Gjakova	Total
Thermal Energy Gross Production	[MWhth]	235,079	9,112	244,191
Loss Quantity in Transmission Network	[MWhth]	5,418	0	5,418
Share of Losses in Transmission Network	%	2.30	0.00	2.30
Own-Consumption	[MWhth]	820	475	1,295
Thermal Energy Net Production	[MWhth]	228,841	8,637	237,478
Loss Quantity in Distribution Network	[MWhth]	19,308	1,728	21,036

Source: ERO Annual report 2019

In order to expand the scope of the program on a more sustainable basis with the establishment of the Kosovo Energy Efficiency Fund, EEREPK's restructuring will secure additional funding, i.e. USD 10.37 million to be channelled through grants to be provided by the EU Instrument for Pre-Accession (IPA II), of which € 9.6 million is in the field of energy efficiency.

All municipalities in Kosovo will benefit from this fund which covers education, health, administration and other sectors. Most importantly, the fund will create a permanent institutional framework, as a financial mechanism, that can contribute to the renovation of public buildings and eventually expand into the residential sector, e.g. apartment blocks, individual houses, and the private business sector.

Energy Investments Outlook

Kosovo fulfills over 90% of its electricity demand from domestic generation, which is largely based on indigenous lignite and does not include natural gas.

There have been investments in new network equipment as well as in maintenance, but also in electricity generation, particularly regarding Renewable Energy Sources.

The transmission network is in good condition, following consistent investments in infrastructure over the years. The transmission capacities fulfil the required criteria, especially following the construction of the 400kV line Kosovo- Albania.
According to the Energy Strategy, in order to cover the local demand for electricity which is growing, and potentially to export electricity, it is foreseen that by 2028 the following generating capacities will be built:
- TPP "Kosova e Re" with an installed capacity of 450 MW;
- Flexible HPP with a capacity of 200 MW;
- Construction of various RES plants
  - 101 MW small HPPs,
  - 180 MW wind turbines,
  - 16 MW biomass, and
  - 85 MW solar energy

With respect to **natural gas**, Kosovo does not have any indigenous natural gas deposits or production and is not connected to any natural gas supply network.

- It is expected that following the finalization of the TAP project, Kosovo will be connected to the natural gas network through the ALKOGAP project, which is in a study phase
- Based on the feasibility study and MCC upcoming projects, exploring the connection to the gas market will be through North Macedonia and Greece.

As for the **oil sector** it should be noted that Kosovo does not have any sources of unrefined oil or capacities to carry out its processing and, therefore Kosovo is a net importer of oil products.
- Currently there are 12 storage facilities which are licensed for wholesale (diesel, gasoline, LPG).
- Wholesale and retail prices are freely set from the market and there is a considerable competition.

RES investment projects are expected to increase in number in the following years. Based on the Register of Applications for the Construction of New Generating Capacities and Admission to Support Scheme from RES there appears to be strong interest.

Through the Kosovo Energy Efficiency Fund, many investments are under way in financing energy efficiency measures in public institutions such as municipalities and ministries in order to implement **energy efficiency** measures and reduce energy consumption. For this fund the Kosovo Government has allocated € 1 million, while World Bank and EU pledged € 10 million. The EBRD Green Economy Financing Facility (GEFF) has also been operational and will continue to provide finance for green economy investments in the residential sector as well as to businesses that provide energy efficiency and renewable energy products and services to households.

References

(1) *Energy Community – Energy Efficiency Agency Annual Progress Report. https://www.energy-community.org/implementation/Kosovo.html*

(2) *ERO - Statement of Security of Supply for Kosovo (Electricity, Natural Gas and Oil). 2019.*

(3) *ERO Annual Report 2019. https://www.eroks.org/zrre/sites/default/files/Publikimet/Raportet%20Vjetor/Raporti%20vjetor%202019_ZRRE_final_alb.pdf*

(4) *ERO Annual Report 2018. https://www.eroks.org/zrre/sites/default/files/Publikimet/Raportet%20Vjetor/Annual%20Report%202018_eng.pdf*

(5) *KESCO https://www.kesco-energy.com/dok/tarifat/Vendim_Tarifat_KESCO.pdf*

(6) *Kosovo Agency of Statistics – Energy Data – Yearly Indicators - https://askdata.rks-gov.net/PXWeb/pxweb/en/askdata/askdata__05%20Energy__Yearly%20indicator/?rxid=cf28934a-103a-488f-8134-600445dcdf5b*

(7) *Kosovo Agency of Statistics. Labor Force Survey in Kosovo, 2019.*

(8) *Kosovo Energy Efficiency Fund. https://fkee-rks.net/*

(9) *KOSTT Annual Balance Sheets. https://www.kostt.com/*

(10) *MED – Energy Strategy of the Republic of Kosovo 2017-2026 Ministry of Economic Development, 'National Renewable Energy Action Plan (NREAP) 2011-2020' (2013).*

(11) *World Bank Kosovo Country Snapshot Data.*

(12) *World Bank. 2020. Western Balkans Regular Economic Report: Spring 2020, The Economic and Social Impact of COVID-19.*

5

MONTENEGRO

Montenegro

Economic and Political Background

Economic profile

As the smallest country of the Balkans, Montenegro has a relatively fragile economy which is transitioning to a market system and is based on financial investments, especially in the energy and tourism sectors (private investment accounts for around one-fifth of GDP). In 2020, the country's economy was severely hit by the COVID-19 pandemic and the global crisis that followed, with the tourism sector (the main driver of growth in recent years) being particularly affected and the simultaneous weakening of both external and domestic demand. Overall, the IMF estimates the GDP to have plummeted by 12% in 2020. Montenegro's economy is expected to rebound thanks to investments supporting construction works and the revival of private consumption, with growth forecasted at 5.5% this year and 4.2% in 2022, though the conjuncture remains volatile and subject to the evolution of the pandemic.

Concerning public finances, Montenegro generally registers a budgetary deficit. In 2020, the country was expected to record a primary surplus; however, the sharp decline in budget revenue (-13.1% y-o-y) and the fiscal measures taken to cushion the effects of the pandemic prompted the government budget deficit to climb to €419.5 million in 2020, equal to 9.8% of GDP, based on data from the Ministry of Finance. The European Commission foresees the deficit to be around 4.7% in 2021 and 3.6% next year. Conversely, over the course of 2020 the debt-to-GDP ratio went from 79.3% to an estimated 90.8%, based on IMF's data.

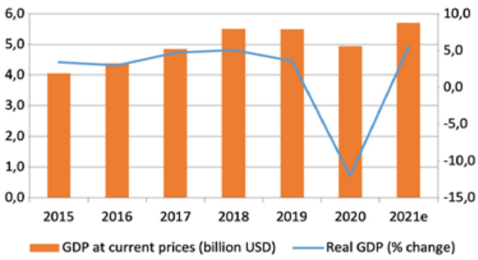
Another matter of concern is the fact that most of the public debt is denominated in USD and the country has an external trade deficit of almost one-fourth of its GDP. Therefore, Montenegro is vulnerable to a decline in external demand and its high financing needs expose the country to potential changes in risk aversion and disruptions in global financial markets. In 2020, low global energy prices and weak internal demand drove inflation into negative territory, with a modest growth expected for 2021 and 2022 (0.7% and 1.1%, respectively). One of Montenegro's main objectives is to join the European Union: the country acquired the official status of a candidate for membership in December 2010. In order to advance in the accession negotiations, it should demonstrate significant progress in several domains, including the rule of law, the fight against corruption and organised crime.

Although decreasing in recent years, the unemployment rate has been historically high and grew to 20.5% in 2020 (from around 15.3% one year earlier, based on data from the Employment Agency of Montenegro). The rate is expected to decrease over the forecast horizon (16.6% in 2021 and 15.9% in 2022, based on data from the European Commission). The country maintains a large informal sector, whereas the labour force participation rate remains low. Moreover, Montenegro is one of the poorest countries in Europe. The latest data available by the European Commission show that almost 24% of the population is at risk of poverty.

A few months after its inauguration, Prime Minister Zdravko Krivokapic's government is far surviving its shaky start. The August 2020 elections ended the Democratic Party of Socialists' ('DPS') three-decade rule, bringing into power a new diverse coalition of parties with a slim parliamentary majority. These include the Serb nationalist alliance For the Future of Montenegro ('ZBCG'), the liberal United Reform Action ('URA') and the centrist Peace is Our Nation ('MNN').

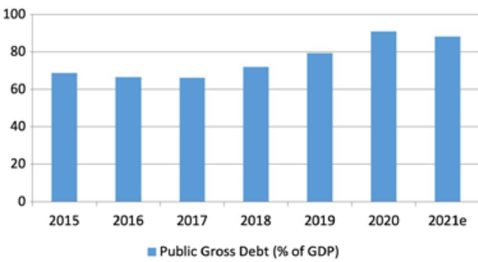
The Krivokapic government, which is comprised mostly of technocrats belonging to or with close ties with the Serbian Orthodox Church, was formed with the express purpose of dismantling the hegemony of DPS, which had designed and captured most of the country's institutional apparatus. This was always likely to be a tall order, given its one-seat majority in parliament and DPS leader Milo Djukanovic's continued occupancy of the presidency – which, although limited in power, is an office that is nonetheless highly influential.

Figure 5.177 **Montenegro's GDP and its annual GDP growth**



Source: IMF World Energy Outlook (October 2020)

Figure 5.178 **Montenegro's Public Gross Debt**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy

The "Energy Policy of Montenegro until 2030" is the main strategic document which establishes three main priorities for the development of the energy sector of Montenegro: security of energy supply, development of a competitive energy market and sustainable energy development. According to the Government Working Plan for 2019 it is envisaged to prepare a new Energy Policy for 2040.

The Energy Policy recognizes three main priorities and twenty key strategic objectives that need to be addressed by 2030. These are shown in Table 5.144:

Table 5.144 **Main priorities of the Montenegrin Energy Policy by 2030**

	Priority	Meaning
1	Security in energy supply	Permanent, secure, high quality and diversified energy supply in order to meet buyers demand
2	Development of a competitive energy market	Development of a competitive energy market Securing liberalized, non-discriminatory, competitive and open energy market on the basis of transparent conditions. Establishing of competition in market activities (electricity and natural gas production and supply), provide the basis for a price policy for all different forms on solely market principles, as well as creating conditions for new energy undertakings likely emerge (independent energy producers, suppliers, traders);
3	Sustainable energy development	Securing the sustainable development of the energy sector based on accelerated, but rational use of indigenous energy resources in compliance with the principles of environment protection, increased energy efficiency (EE) and increased use of renewable energy sources (RES), as well as the need for the socio-economic development of Montenegro.

Source: Energy Policy until 2030

The **"Energy Development Strategy of Montenegro 2030"** was adopted in 2014. The Energy Development Strategy specifies long-term development objectives and guidelines for the development of energy supply and meeting of energy demand, while taking into account technological and economic criteria and environmental protection criteria; the development direction of energy infrastructure, taking into account possibilities for encouraging the use of renewable energy sources and increasing energy efficiency and long-term energy balance forecasts, timeline and methods to be used for tracking progress and monitoring the achievement of objectives, as well as the assessment of their effects on the economy; tentative financial resources for the implementation of the strategy.

The **National Renewable Energy Action Plan (NREAP)** by 2020 was approved by the Government on 18th December 2014. NREAP defines dynamic utilization of natural resources, as well as the planned use of technologies required to meet the national target for the share of energy produced from renewable sources in the gross final energy consumption.

Fourth Energy Efficiency Action Plan (NEEAP) for the period 2019-2021 was approved by the Government on 27th June 2019. NEEAP is fully in line with the key strategic documents in the field of energy and sustainable development while it also defines the national target for energy efficiency.

Government Institutions

The role of the Montenegrin Government in the energy field is to define and implement: (a) the National Energy Policy and the Energy Development Strategy, (b) long-term and annual energy balances and policy for their implementation, and (c) provide for the implementation of environment protection measures.

The key stakeholders in energy sector of Montenegro are:

- The Ministry of Economy (MoE), through the Directorate for Energy, Directorate for Energy Efficiency and Directorate for Mining and Geological Explorations, is responsible for developing and implementing energy policy. According to the Law on Energy and the Law on Efficient Use of Energy, the Ministry is also responsible for the preparation of strategic documents in the energy field, as well as for the development of the legal framework. The Ministry of Economy is also responsible for energy system and policy modelling. However, due to the lack of capacity and resources in the ministry, this process is usually supported by the donor community.

The review and update of strategic documents related to energy is mainly coordinated by relevant directorates within the ministry.

- The Energy Regulatory Agency (REGAGEN) is the energy regulator of the country. REGAGEN was established in 2004 as an autonomous, functionally independent, non-profit organisation that carries out its public authorisations in the energy sector in accordance with the Law on Energy. Regulation is carried out in a non-discriminatory and transparent manner in accordance with EU directives. In addition, the Law on Energy specifies duties and responsibilities of REGAGEN in terms of its regulatory oversight of energy entities.
- The Ministry of Sustainable Development and Tourism (MoSDT) is the governmental authority which is responsible for several areas that interact with development of the energy sector, particularly: spatial planning, construction, environmental protection and climate change. Inter-ministerial cooperation regarding activities such as adoption of spatial plans, construction of energy infrastructure or development of building codes is very important for the coherent development of the energy sector. The MoSDT is also responsible for the legal framework in the area of environmental protection as well as for the implementation of the UNFCCC, the Paris agreement.
- The Nature and Environmental Protection Agency is the governmental authority responsible for issuing environmental permits, i.e. Strategic Environmental Assessment (SEA) and Environmental Impact Assessment (EIA) forms.
- The Chamber of Economy of Montenegro is a business association representing the general interests of the economy and all economic entities in Montenegro. The Chamber of Economy also actively presents business opportunities and encouraging investment in the Montenegrin economy, relevant to the development of the energy sector of the country.
- The Administration for Inspection Affairs is an authority responsible for inspection affairs in different areas which are relevant for the implementation of the legal framework in the energy field, as well as investment in energy infrastructure.

Energy Demand and Supply

The key facts concerning energy production and consumption in Montenegro for the years 2018, 2019 and 2020 (est.) are shown in Table 5.145.

Table 5.145 **Energy production and consumption for 2018-2019 and estimates for 2020 (in ktoe)**

	2018			2019			2020		
	Realised			Realised			Anticipate		
	Generation	Consumption	G/C	Generation	Consumption	G/C	Generation	Consumption	G/C
	ktoe		%	ktoe		%	ktoe		%
Electricity	322	298	108	302	304	99	297	311	95
Biomass	199	199	100	193	193	100	201	201	100
Coal*	30	30	100	31	31	100	31	31	100
Petroleum products	0	332	/	0	312	/	0	367	/
Total	551	859	64	526	840	62	529	910	58

Source: Energy Balance for 2020
*the coal that has been used in TPP Pljevlja is not shown here but the equivalent is taken into account in electricity generation

The electricity sector of the country is highly dependent on the country's hydrological situation and the water level in the rivers, as evidenced by the fluctuation of the share of hydropower in the total primary energy supply over the years, e.g. sharp decreases of 56% and 31% in years 2011 and 2014, correspondingly.

The existing industry is characterized by a high level of energy intensity, requiring large amounts of electricity, which has a predominant share in the energy balance. In the past few years progress in energy management in aluminium and steel production has been achieved so that energy consumption is reaching expected level. In 2018 total energy consumption amounted 859 ktoe, out of which 35% was covered by electricity, 39% by petroleum products, 23% covered from biomass and 3% was covered by lignite (excluding the coal used by thermal power plant in Pljevlja).

In 2018 the domestic electricity production covered total electricity consumption and some amounts of net exports have been realized (274GWh).

The electricity production is realized from hydro power plants amounting 2137 GWh or 57%, 1444 GWh or 39% is realized from thermal power plant while the rest amounting to 163GWh or 4% from wind farms.

In 2019 the situation was slightly different mostly because of the hydrological conditions. The generation from hydro power plants was lower amounting 1688 GWh. On the other hand, because of the expansion of wind farm projects, the generation from wind amounted to 299GWh. While thermal power plants generated 1520 GWh. The difference between generation and consumption was almost the same and hence only a small amount of net electricity was imported (26GWh).

Ministry of Economy of Montenegro in its Energy balance for 2020 has planned for a total electricity of 3454GWh, out of which 1823GWh from HPP, 312GWh from wind farms, 2GWh from solar plants and 1317GWh from thermal power plant.

Montenegro imports 100% of its oil needs (oil corresponds to 39% of the total energy consumption). The country has large enough hydroelectric potential, but only 17% of it is actually exploited.

In view of increased energy consumption, the imports of oil derivatives have been growing over the last decade. On the other hand, the transportation sector is 100% dependent on imported oil apart of the railway system which uses electricity. It is significant to note that biomass is being used in high amounts while small amounts have been exported and almost 100% of it corresponds to domestic production. The most significant trend of the last decade has been the increase in the overall energy consumption.

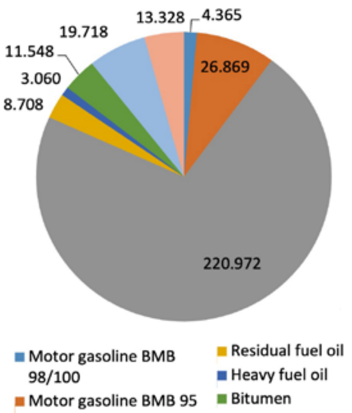
In Montenegro there are no oil refineries and there is no natural gas network and pipelines to provide natural gas.

The Energy Market

Oil and Petroleum Products

Current balance overview of oil products is given in the next Figure 5.179:

Figure 5.179 **Oil and petroleum products balance in tons for 2019**



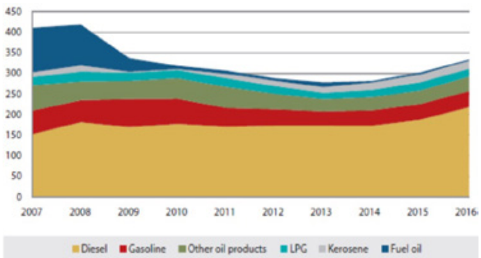
Source: Ministry of Economy of Montenegro 2019

Montenegro does not have its own oil production or refining industry, and all oil products are imported. The main characteristic of the oil retail market in Montenegro is the leading role of Jugopetrol AD (owned by Hellenic Petroleum) which has a dominant position compared to other market players dealing with marketing and sale of oil products. Total consumption of oil products in 2019 amounted 308568 tons, out of which diesel corresponded to 220972 tons, which was the most widely used oil product in Montenegro with a share of 72% in total consumption.

The Ministry of Economy of Montenegro anticipated an increase of oil product consumption by 17% in 2020. As significant increase is anticipated for diesel which is mainly used in the transport sector, as well as more than doubling of the consumption of bitumen as it is used for the construction of the Bar-Boljare highway.

Overall, the consumption of oil products decreased by 19% over the last decade. Figure 5.180 shows that the trend of reduced consumption is mainly due to a sharp decrease in the consumption of fuel oil (mazut). The latter is associated with the decline in industrial production of aluminium oxide. The consumption of diesel and kerosene has increased by 43% and 69%, respectively, and is related to the growing energy demand of vehicle and airplane fleets. As of 2016, 96% of diesel was used by transport, and the remaining 4% was used as a heating fuel.

Figure 5.180 **Consumption of oil products 2007-2016**



Source: Ministry of Economy of Montenegro 2019

The transport sector dominates the consumption of oil products. The sector's share has been increasing over time, reflecting not only the increasing demand of the transport sector, but also the decline in industrial production since 2009.

Upstream sector - Oil and Gas Exploration

Most of the available data refers to offshore hydrocarbon exploration. So far, around 10.000 km2 of 2D seismic profiles, 4 drillings and around 310 km2 of 3D seismic researches have been carried out in the offshore areas. Exploration which has been carried out so far indicates the existence of hydrocarbon reserves; however more reliable estimations of hydrocarbon deposits may be provided only after the completion of the verification phase of identified reserves.

This paragraph needs to be totally revamped. ENI-Novatek have recently completed their exploration drilling, offshore Montenegro, but they have not announced any results yet. Energean is expected to announce its plans regarding a potential exploration drilling in 1Q 2021.

The findings of the first drillings will show whether there are commercially exploitable reserves of oil and gas. The results of the exploratory drillings will show further if there are sufficient oil and gas reserves in the chosen structures.

In accordance with the Agreement on Concession for Research and Production of Hydrocarbon in blocks 4, 5. 9 and 10, signed with the Italian-Russian Consortium Eni-Novatek in 2016, 3D geophysical imaging of the blocks was carried out in November and December 2018.

The seismic research for oil and gas in offshore areas began on November 2018. Surveys are planned for approximately 1,200 square kilometers of sea area, for which the concession was awarded to the Italian-Russian consortium Eni-Novatek. With the help of sound-air cannons, as well as special geomicrophones, which are several kilometers long and connected to ships, an assessment will be made of whether there are grounds for commercial exploitation of the oil and gas deposits in the Montenegrin waters. Some analyses show that Montenegro has 51 billion cubic meters (bcm) of gas and 144 million cubic meters (mcm) of current resources, which correspond to about 438 million barrels of oil. The data referred to the 330 sq. kilometers in Ulcinj.

The state will reap all profits from oil exploitation through the application of a surface charge, a refund for oil and gas produced, and a tax of 54 per cent. In the final analysis, the estimate is that, depending on the scope of exploitation, the state would receive between 62% and 68% of the total revenues from these activities.

Downstream and midstream sectors infrastructure

The storage of petroleum products and LPG in Montenegro (2018) was undertaken by 32 entities, of which 22 performed both activities. The storage of petroleum only products was undertaken by seven entities, while only three entities involved in LPG storage. Total storage capacities corresponding to petroleum products the end of 2018 amounted to 142,327 m³, of which gazoline product storage capacities corresponded to 138,959 m³, while LPG storage capacities amounted to 3,368 m³. In 2018, the storage capacity was increased by 656 m³ (632m3 gazoline products and 24m3 petroleum gas).

Of a total storage capacity of 142,327 m³, some 126,292 m³ belong to Jugopetrol AD Podgorica, of which its Bar Installation is 110,170 m³, petrol stations between them have 6.895 m³, aviation services in Podgorica and Tivat share to 9,040 m³, while three yachting services, in Budva, Herceg Novi and Kotor, share 187 m³. A part of the 16,035 m³ storage capacity belongs to other energy entities, which undertake the storage of petroleum products and LPG in gas stations and yachting services. The energy entity with the highest storage capacity for LPG is Montenegro is Bonus DOO Cetinje, with a total capacity of 1,100 m².

Security of Supply

Montenegro depends entirely on imports of oil derivatives although there are good prospects for crude production from local oil fields and from the exploitation of the country's hydrocarbon resources. Consumption of oil derivatives in 2018 amounted to 332 ktoe, which mainly consisted of diesel fuel, gasoline and jet fuel/TNG. Consumption of fuel oil has dropped due to reduced use by the Aluminum Factory of Podgorica because new technology has been introduced in the plant. The Aluminum Factory is mainly using gas to cover its own needs so that the use of residual fuel oil has been eliminated, and instead LPG is being used in the various industrial processes.

Consumption of oil derivatives in 2019 amounted to 312 ktoe, while 367 ktoe are anticipated for 2020. Oil derivate consumption amounted around 38% of total energy consumption in the country. Since petroleum products are fully imported, they are a very important factor in terms of security of energy supply.

In addition, Montenegro has limited brown coal and lignite reserves. The required amounts are exploited from coal mines in Berane and Pljevlja.

Planned projects

The Government of Montenegro is implementing a number of preparatory steps for potential gasification which could be achieved through infrastructure development related to the Ionian-Adriatic Pipeline (IAP) and/or the Trans Adriatic Pipeline (TAP). The construction of a natural gas pipeline network will enable both a stable natural gas supply to Montenegro and its transit to other countries in Western Balkans. The Government of Montenegro has already implemented the following activities to support the IAP and TAP projects. In 2016, the IAP Project Management Unit (PMU) was established, consisting of one representative from the national energy authority and one representative from the natural gas transmission system operator (TSO), from all four signatories to the Memorandum of Understanding and Cooperation on the implementation of the IAP project - Albania, Bosnia and Herzegovina, Montenegro and Croatia.

Map 5.48 **Ionian - Adriatic Pipeline in Montenegro**

Source: Ministry of Economy of Montenegro 2019

In 2017, the Government adopted a Master Plan for the development of the gas transport system (gasification) of Montenegro, accompanied by a report on strategic environmental impact assessment as well as guidelines for the planning of priority investments in gas pipeline projects. The Master Plan explains the construction of the TAP (with total capacity of 5 billion cubic meters of gas per year and with a total length of 530 km), which is an important project for EU gas infrastructure, as well as the gasification of several large cities inside the country.

Natural Gas

Natural Gas supply and demand and relevant infrastructure

Since the last SEE Energy Outlook (2017) nothing much has been done in order to bring gas to the country. Still there is no access from international networks although there are several possible ways to supply the country with gas. The most likely option is the Ionian Adriatic Pipeline (IAP) project crossing Montenegro.

Montenegro still has not developed any gas infrastructure nor has a gas market been established. It is assumed that, thanks to the planned project of the Ionian Adriatic Pipeline (IAP), it will become possible to introduce natural gas in the near future. Estimations of final consumption of natural gas are based on the assumption that the IAP regional pipeline would pass along the coast of Montenegro and that gasification would include only coastal towns. Other than raising the energy standard of gasified households, this would represent a strong incentive to further develop industry, especially tourism, along the coastal area. By 2030, final gas consumption could reach 46 million of m3. Households are likely to participate with a large share in consumption, followed by industry. Services, mainly tourism, could see consumption from 9 to 12 million of m3 of natural gas.

National NG Policy - Strategic Plan

The Energy Development Strategy of Montenegro by 2030 stipulates the following recommendations about further development of the gas sector:

- Continue the recent exploitation activities in potential oil and gas reserves in the Adriatic Sea,

- Continue with the feasibility study for the Ionian Adriatic Pipeline and determine the optimal route through the territory of Montenegro taking in consideration long-term economic growth of the country,
- Continue with intensive cooperation with other participants in key projects (IAP and TAP) in the region.

The most important project by far is the Ionian-Adriatic Pipeline (IAP), which would connect Montenegro with Croatia and Albania and allow for gas imports into the country. Natural gas is a sector which is planned to play an important role in the energy market of Montenegro in the coming years. The development prospects of natural gas appear promising for future investment. Given the fact, that tourism is the upcoming and dominant sector of Montenegrin economic development, the introduction of a system providing natural gas will definitely have a positive impact on the extension of the tourist season.

Solid Fuels

Supply and Consumption

After hydropower, coal is the second most important source of electricity production in Montenegro. Coal is mined in the north of the Montenegro in the Pljevlja region. This region is home to three coal basins: Pljevlja basin (under exploitation); Ljuce-Sumanski basin (almost depleted); and Maoce Basin (new coal mine). According to Montenegro's energy development strategy the total balance reserve of the Pljevlja region amounts to around 188.4 million tons. All coal produced in Montenegro is used in the local market, where about 97%-98% is consumed by the TPP Pljevlja, and the rest is consumed by households, industry and services. Thus, the production of the coal is mainly dependant on the electricity production cycle of the Pljevlja TPP, which, in turn, is influenced by the availability of hydropower and energy demand. It should also be noted that the power plant underwent modernisation in 2009, which negatively impacted coal production in that year. The Pljevlja TPP, which has been in operation for more than 35 years, will soon be upgraded in order to comply with the requirements of EU environmental standards. In March 2018, the Elektrorprivreda Crne Gore (EPCG), the company owning the TPP, selected a consultant to design the reconstruction of the plant.

Local production and exploration

The total production of lignite from the Pljevlja coal mine in 2018 was 1.539.122 tons, while in 2019 it reached 1.579.048 tons whith the Ministry of Economy of Montenegro announcing plans for 1.602.000 tons for 2020. In addition, brown coal is being exploited from the coal mine in Berane. The total production of brown coal from this mine was 56.448 tons in 2018, 33.635 tons in 2019 while according to Ministry of Economy of Montenegro plans of 58.300 tons production in 2020 is expected. Possible reserves in Pljevlja amount to 198.9 million tons while those of the Berane basin are estimated at around 158 million tons. However, due to inadequate research, total presumed exploitable reserves in Berane fields have been estimated at only 18,5 million tons. The company Rudnik Uqlja AD Pljevlja exploits coal in Pljevlja area with 100% of its shares being owned by the National Power Utility (EPCG) which is government owned.

Planned new projects

There are no plans for the construction of new TPP in future after the government decided not to build the TPP Pljevlja II plant due to environmental, economic and social reasons

Montenegro's power utility Elektroprivreda Crne Gore (EPCG) has launched a tendering process for the environmental reconstruction of the Pljevlja thermal power plant (TPP) Pljevlja Block 1. The upgrading will increase the TPP's installed capacity from 225 MW to 300 MW. Environmental upgrading will result in a reduction of all emissions and coal combustion products, as well as of chemical processes accompanying electricity generation so as to limit them, all in line with the statutory regulations of Montenegro and the EU directives on emissions from coal-fired TPPs.

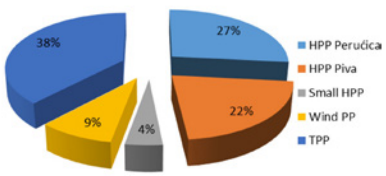
Electricity

Electricity Supply and Demand

The electricity market in Montenegro is small, with a total installed capacity of 1025 MW provided by HPPs, the Pljevlja TPP and the Krnovo and Mozura wind farms.

The electricity sector of the country is highly dependent on the country's hydrological situation and the water level in the rivers, as evidenced by the fluctuation of the share of hydropower in the total primary energy supply over the years, e.g. sharp decreases of 56% and 31% in years 2011 and 2014, respectively. A favorable hydrological situation in 2010 and 2013 allowed HPPs to operate at maximum capacity during these years. The availability of hydropower has clearly influenced the variability of the net import-export balance over time, but this is not on its own the most important factor. The production capacities have been constantly increasing since 2014 mostly due to the development of small hydro and the construction of the first wind farm that became operational in 2017.

Figure 5.181 **Power plant share in generation 2020**



Source: Energy Balance for 2020, Ministry of Economy

The Ministry of Economy of Montenegro anticipated total electricity generation of 3454 GWh in 2020. 27% of the electricity is planned to be generated from HPP Perucica, 22% from HPP Piva, 4% from Small HPPs, 9% from Wind PP and 38% from thermal power plant Pljevlja. Anticipated electricity production in 2020 is likely to be around 1% lower than the realized generation in 2019.

Installed Capacity

Electricity generated in Montenegro is mainly produced from the following plants:

- Coal Thermal Power Plant (TPP) Pljevlja with an installed capacity of 218.5 MW;
- Hydropower Plant (HPP) Perucica with an installed capacity of 307 MW;
- HPP Piva with an installed capacity of 342 MW;
- 19 small HPPs with total installed capacity of 33 MW;
- Krnovo wind farm with installed capacity of 72 MW
- Mozura wind farm of 46 MW.

Thermal Plants

There is only one thermal power plant in Montenegro in the region of Pljevlja where most of the coal mines are located. It began operation in 1982 and the total amount of coal used in 2019 was 1442668 tons (calorific value 9.211 kJ/kg) while the plan for 2020 is 1% higher. The installed capacity is 218.5 MW with the annual generation output in 2019 of 1520 GWh, while the plan for 2020 is 1317 GWh.

Hydroelectric plants

There are two big hydropower plants in Montenegro and seven small ones that are owned by EPCG. The hydroelectric power plants are: "Perućica" with installed capacity 307 MW and the Hydro Power plant "Piva" with installed capacity 360 MW. The Perućica plant in 2019 produced 841 GWh which corresponds to 24% of electricity demand. The HPP Piva has three generator sets, each with capacity of 120 MW and it produced in 2019, 778 GWh which corresponds to 22% of electricity demand. In 2020 the generation from HPP Perucica is planned to 920 GWh while in HPP Piva 750 GWh.

Apart of 7 small HPPs owned by EPCG, significant number of small hydro power plants have been constructed by private owners. A total of 90 MW of new generating capacity of small HPPs should be put into operation by 2021. The new small HPPs can play a significant role in the energy system, as they can potentially increase the existing electricity production by about 10%. From 2015-2017, the Government of Montenegro conducted three tenders and granted 18 concessions for the construction of 37 small HPPs. From 2014-2018, the construction of 13 small HPPs was completed.

Wind farms

There are two wind farms: Krnovo wind farm with installed capacity of 72 MW and Mozura wind farm with installed 46 MW.

Nuclear plants

Montenegro does not have any nuclear plants and does not have any plans for the future.

RES applications

Incentives for the purpose of obligatory share of energy from renewable sources in total final consumption are defined by the Law on Energy and consist of: privileged status during purchase of electricity produced, incentive prices at which that energy is purchased, period of validity of privileged status for purchase of electricity, exemption from balancing service payment system and priority in the transmission of generated electricity to the system. Electricity producers, after obtaining the status of eligible producer, are entitled to incentive measures.

Feed-In Tariffs (FIT) were established by the Law on Energy and further regulated by the Decree on Tariff System for Determining Incentive Prices for Electricity Produced from RES and High Efficiency Cogeneration. The FITs are based on the type of RES and the scale of the installation According to the law, FITs are provided for 12 years. In 2019 the Government of Montenegro cancelled FIT for new producers and electricity price from new energy generation facilities will be formed on market based models without privileged status and guarantied purchases.

Planned New Capacity - Investments

All the facilities for the electricity production (plants) and transmission (grids) are too old and the need of modernization is crucial for the electricity sector of Montenegro. Apart from renovation, Montenegro must invest in the construction of new electricity production plants to meet the growing needs which accompany high economic development rates. Based on a letter of interest by the German company WPD, a tender for the lease of state property for a construction of wind farms in the municipality of Budva and Bar was completed and the winner was WPD. The tender predicts construction of WPP 75 MW of installed capacity. It is important to note that the tender involves the implementation of the project according to the market principles, respectively, a decision that there are no financial incentives in terms of the guaranteed purchase price. The only thing that can be offered is purchase at market prices.

Taking into account the new spatial planning preconditions and the interest of investors, the tender will be realized during 2020 for lease of the state property for the construction of solar power plant at the site Velje Brdo, Municipality of Podgorica. The tender will provide for the construction of a power plant of at least 50 MW of installed capacity. The tender will be implemented according to market principles.

Construction of the WPP Gvozd implies the continuation or the second phase of construction of the WPP Krnovo, which is already part of our production system. The project is currently under development by the national energy company (EPCG) and Austrian Ivicom (one of the companies that have developed the project WPP Krnovo). Company Ivicom has contracted the development of the Study of utilisation of wind power potential with an expected production of electrical energy and the Feasibility study of the project. Development of these studies is ongoing. Preliminary data show that the value of the project is about 70 million euros, and installed capacity of power plant 50 MW. Depending on the results of the final studies, EPCG business decision on the next steps of the project will be defined. This means that then will be chosen the optimal scenario of the finance arrangements for the project, selection of contractors, or potential selection of partners for the eventual establishment of a project company for the realisation of this project.

Currently, activities are under way and involve forming of a final base for realisation of the project of construction of the HPP Komarnica. Contract on development of Conceptual design with Feasibility study and an Environmental impact assessment, worth 1.3 million euros, was signed in 2018. Adoption of the Detailed Spatial Plan on the proposed solution is expected in 2019, which will create preconditions for announcement of tender for the creation of the main project and execution, by the end of this year.

According to the preliminary data of the analysis of the project worth, it will amount to 260-290 million euros, and the installed capacity of the plant will be 155 MW with annual production of about 210 GWh.

The realization for the construction of solar power plants with an installed capacity of up to 1 MW is possible through the issuance of an energy permit. Based on 14 energy licensing decisions issued by the Ministry of Economy, it is planned to build power plants on roof structures with a total installed capacity of about 7.4 MW and planned annual production of about 9.4 GWh. At the time of preparation of the report, the solar power plant on the roof of the investor-owned hall in Bandići, Danilovgrad Municipality, with an installed capacity of 416 kW and planned annual production of 556 MWh, has acquired the status of privilaged producers.

According to the Conclusion of the Government of Montenegro, the Ministry of Economy on 19 May 2018 published a Public Invitation for Lease of State-Owned Land at the Site of Briska Gora - Ulcinj Municipality for the Construction of a Solar Power Plant. Following the invitation, bids from three bidders were received, and it was determined that the first-ranked bidder was the Fortum and EPCG Consortium (consisting of Fortum Corporation, Finland, Elektroprivreda Crne Gore AD Niksic and Sterling & Wilson, India), which committed itself to land leased a 250 MW solar power plant. In accordance with the above, the Government of Montenegro has made the Decision on long-term lease of the land in question for a period of 30 years, after which the Land Lease Agreement for the construction of a straw plant with the aforementioned consortium was signed.

Cross-border interconnections

The transmission system operator Crnogorski elektroprenosni sistem (CGES) belongs to the State (55% of the shares), the Italian TERNA (some 22% of the shares) as well as several investment funds. The electricity market operator COTEE is fully owned by the State.

CGES has a transmission network consisting of the transmission lines long over 1300 km (the total length of the transmission lines in the territory of our country, which is the fixed assets of CGES, is 1305.86 km). The transmission network consists of 45 transmission lines:

- Six 400 kV transmission lines (Lastva - Podgorica 2, Lastva - Trebinje, Podgorica 2 - Ribarevine, Ribarevine - Peć, Ribarevine - Pljevlja 2 and Podgorica 2 - Tirana);
- Eight 220 kV transmission lines (HPP Perućica - Trebinje, Podgorica 1 - Perućica, Podgorica 1 - Koplik, Podgorica 1 - Mojkovac, Mojkovac - Pljevlja 2, Piva - Pljevlja 264, Piva - Pljevlja 265, Piva - Buk Bijela;
- Thirty-nine 110 kV transmission lines, of which three are double circuit lines (2x110 kV) and four are operating at 35kV;
- Two 110 kV cables (Podgorica 3-Podgorica 5 and 2 Nikšić-Kličevo)

CGES performs the activity of electricity transmission in Montenegro through the transmission network at 400 kV, 220 kV and 110 kV voltage levels, as well as system control and maintenance and development of the transmission network.

CGES has a transmission network consisting of the transmission lines long over 1300 km (the total length of the transmission lines in the territory of Montenegro, which is the ownership and fixed assets of CGES, is 1305.86 km) and 24 substations at 400kV, 220kV and 110kV voltage levels. The total transformation capacity of the transmission network of Montenegro is 3846.5 MVA (with a total of 53 transformer units).

Montenegro and Italy have officially put into operation their submarine power link on 17 November 2019, built by Italy's Terna in a joint project with Montenegrin transmission system operator CGES. The link is seen as the first "electrical bridge" between the Balkans and the rest of Europe.

The interconnection will allow a bi-directional exchange of electricity between the two countries of 600 MW of power initially, which will become 1,200 MW when a second cable is laid within the next few years.

The 1.15 billion euro ($1.27 billion) project consists of an interconnection between Montenegro - Italy (underwater cable) and enhancement of the internal 400 kV network in Montenegro. The total length of the power line is 445 km and 423 km of it is laid on the seabed. SEE CAO is in charge for organization of capacity auctions on undersea power interconnector between Italy and Montenegro. First yearly auctions for 2020 on ITME border were conducted on 11th December, monthly auctions for January were held on 20th December while Daily allocation started on 27th December for delivery day 28th December. This whole process was followed by great interest of energy traders and resulted in greatest number of participants so far.

Tariffs

The price of electricity for households with two-tariff meters in Montenegro amounted to € 10.30 c/kWh, including all taxes and VAT, while the average price of electricity in EU countries was € 21.10 c/kWh. In 2018, the average realized electricity price, including the fee for the promotion of renewable energy sources for customers connected to the distribution system, amounted to € 8.65c kWh (not including VAT), which was 0.28 € c/kWh or 3.31% more than in 2017. This increase was due to an increase in prices in the wholesale electricity market, in relation to which EPCG, as a supplier, adjusted the prices at which it supplies distribution customers.

Electricity prices in 2018 compared to 2017 are for customers connected to:
- 35kV higher by 0.04 € c/kWh or 0.67%;
- 10 kV higher by 0,36 € c/kWh or 4,84%;
- 0.4 kV overall higher by 0.29 € c/kWh or 3.31%;
- 0.4 kV - households two-tariff measurement higher by 0.26 € c/kWh or 3.11%;
- 0.4 kV - households single tariff higher by 0.37 € c/kWh or 3.93%.

On 13 December 2019, EPCG approved prices for end users electricity supply for the period 01 January - 31 December 2020, for all customers' categories. Table 5.146 shows prices and tariff models for households including fee for RES within Green Model.

Table 5.146 **Electricity tariffs models for households**

Basic Model	VT	5,2424	€c/kWh
	NT	2,6212	€c/kWh
Blue Model	VT150	4,8434	€c/kWh
	NT150	2,4217	€c/kWh
	VT+	5,5340	€c/kWh
	NT+	2,7670	€c/kWh
Red Model	VT+NT	4,4932	€c/kWh
Green Model	VT	5,2424	€c/kWh
	NT	2,6212	€c/kWh
	Naknada	0,2000	€c/kWh

Source: Electric power company of Montenegro - EPCG (https://www.epcg.com/domacinstva/tarifni-modeli)

The price of electricity is not the same during the day. Different prices apply in the bills as lower (NT) and higher (VT) tariffs.

Planned HPP and Small HPP

In the past, significant activities were carried out within the framework of small hydropower projects over a large number of water areas. Based on the six tendering procedures implemented, 18 concession contracts are being implemented, which envisages the construction of 37 small hydropower plants. Also, on the basis of the energy license, 18 concession contracts were concluded, which envisaged the construction of 18 small hydropower plants whose installed capacity is below 1 MW individually. In accordance with the above, on the basis of 36 concluded concession contracts, a total of 55 small hydropower plants have been planned, of which 13 have been completed so far and have received a operating permit. The total installed capacity of all small hydropower plants whose construction is foreseen by the concluded contracts is about

96 MW, and the total annual production is about 313 GWh. The value of investments for all anticipated small hydropower plants is estimated at around € 160 million.
Also see 5.3.

Renewables

Overview of sector's development

Taking into account the importance of renewable energy sources from an environmental and technological point of view, in strategic planning of energy development, Montenegro has decided to develop the production of energy from renewable sources and to achieve the national target set by Decision 2012/04/MC-EnC of 18 October 2012, adopted at the 10th meeting of the Ministerial Council of the Energy Community. The decision establishes an obligation for Montenegro to achieve the national target, which provides that in Montenegro the share of energy from renewable sources in total gross final consumption will reach the level of 33%, as well as the obligation for Montenegro to implement Directive 2009/28/EC on promotion. the use of energy from renewable sources in its legislative system.

In order to fulfill the established obligations, the Government of Montenegro adopted a Program for the Development and Use of Renewable Energy Sources, which sets out the national targets for the use of renewable energy sources, incentive measures, deadlines and the timetable for its implementation.

Pursuant to the Law on Energy and the Strategy of Energy Development of Montenegro until 2030, the Government of Montenegro has adopted the National Action Plan for the Use of Energy from Renewable Sources until 2020, which defines the way of using energy from renewable sources, as well as the planned use of technologies needed. to meet the national target for the share of energy produced from renewable sources in total final energy consumption.

The technologies used for the production of electricity from renewable sources in smaller production plants are still not economically competitive with conventional power plants, so in Montenegro a system of guaranteed purchase of produced electricity at incentive prices from preferential producers of electricity from renewable sources and high-efficiency cogeneration is used. In addition, privileged producers are also exempt from the balancing costs they incur.

Installed capacity per source

Electricity generated in Montenegro is mainly produced from the following plants:
- Hydropower Plant (HPP) Perucica with an installed capacity of 307 MW;
- HPP Piva with an installed capacity of 342 MW;
- 19 small HPPs with total installed capacity of 33 MW;
- Coal Thermal Power Plant (TPP) Pljevlja with an installed capacity of 218.5 MW;
- Krnovo wind farm with installed capacity of 72 MW
- Mozura wind farm of 46 MW.

As far as geothermal is concerned, no significant geothermal potential has been identified in Montenegro.

Planned new major projects

See subchapter "Planned new capacity – Investments" in Electricity.

Energy Efficiency and Cogeneration

National targets

According to the Energy Community Treaty membership, the obligation of Montenegro is to achieve the indicative energy savings target which represent savings in the amount of 9% of average final consumption of energy in the country over a five-year period. According to the Directive, the established period of time for meeting the indicative energy savings target is from 2010 until 2018.

Concerning the realization of the indicative energy saving target for the period 2010-2018, a preliminary analysis (using the "bottom-up" method - BU) was made, on the basis of the available data, which shows that the energy savings achieved in the previous nine-year period amounted to 49.76 ktoe, which represents 84.5% of the overall indicative target. The calculation of the energy savings with "top-down" method (TD) was not possible due to the unavailability of data from the energy balances for 2018.

The process of preparation of official energy balance for 2018 is to be finalized, after which energy savings will be calculated by using the TD method in the separate analysis, which will be completed by the end of January 2020. Within the same analysis, a more comprehensive analysis of savings will be made by using BU methods.

The government of Montenegro adopted the fourth Energy Efficiency Action Plan for the period 2019-2021 (4th APEE) in July 2019. For the period 2019-2021 EEAP determined an indicative target at annual level in the amount of 4.16 ktoe of final energy consumption (i.e. 6.54 ktoe expressed in primary energy equivalent).

Incentives based initiatives in the building sector

In order to further develop the basic legal framework in the field of energy efficiency on the final consumption side, as well as to harmonize national legislation in line with EU directives, the Ministry of Economy during 2018 prepared 14 additional bylaws to implement the Law on Efficient Use of Energy. Their enactment is foreseen in 2019-2020, including the following:

Furthermore, the Ministry of economy has implemented a number of energy efficiency projects in order to improve EE in buildings, jointly with international and local partners:

- MEEP - Montenegrin Energy Efficiency Project
- EEPPB - Energy Efficiency Program in Public Buildings.
- MONTESOL - Interest-free credit line for installation of solar-thermal systems for households
- ENERGY WOOD - Interest-free credit line for installation of heating systems on modern biomass fuels (pellets, briquettes) for households
- SOLARNI KATUNI - Project related to installation of photovoltaic solar systems in summer pasture lands.

The Ministry of Economy has also launched an Energy Efficient Home program aimed at reducing heating costs and increasing household comfort, achieving a significant reduction in CO_2 emissions in the household sector, and developing a market for biomass heating systems in Montenegro.

In order to reduce pollution in the Municipality of Pljevlja, co-financing of pellet procurement is carried out for citizens who already have pellet heating.

EU funded energy efficiency programmes in the building sector

Implemented activities and achieved results:

1. ENERGY WOOD - interest free loans for the installation of heating systems using modern biomass. The Ministry of Economy has implemented the Energy Wood program, with the aim of establishing an attractive and sustainable financial mechanism for providing interest-free loans to households for installing heating systems (boilers and stoves) on modern biomass (pellets, briquettes). Under the Energy Wood program, citizens were able to apply for loans up to € 3,500, with a repayment period of up to 5 years, and an interest rate of 0%, for installing a heating system, ie. stoves and boilers on modern forms of biomass. In the previous period, 3 phases of the Energy Wood program were implemented, out of which the last 2 in the implementation period of the 3rd EEAP. Details of the program implementation are given in the table below:

Table 5.147 **Program implementation**

Phase (duration)	Funds	No. of installed heating systems
I (2013-2015)	130.000 € - donation from the Luxembourg Development Agency	243
II (2015-2018)	240.000 € - donation from the Government of the Kingdom of Norway	532
III (2017-2018)	85.000 € - state budget	235

Source: Fourth Energy Efficiency Action Plan for the period 2019-2021, Ministry of Economy

2. SOLARNI KATUNI - Installation of photovoltaic solar systems in summer pasture lands

The Ministry of Economy in cooperation with the Ministry of Agriculture and Rural Development is implementing project "Solarni Katuni", aimed at installing photovoltaic solar systems in households residing on summer pasture lands which are not connected to electricity grid. Within the project, 243 photovoltaic systems were installed in summer pasture land, so far out of which 54 in implementation period of 3rd EEAP.

ENERGY EFFICIENT HOME - interest-free loans for installing heating systems on modern biomass and performing works to improve the energy performance of the building envelope.
In 2018, the Ministry of Economy provided € 120,000 in for the implementation of the program Energy Efficient Home, which began in October 2018. This program is a continuation of the program ENERGY WOOD, which has been expanded by other EE measures.

The goal of the Energy Efficient Home program is to offer households in Montenegro, through interest-free loans (up to 8,000 €, with a repayment period of up to 6 years), the opportunity to achieve economic and energy savings by using biomass heating systems and financing works to improve energy performance of the building envelope (installation of thermal insulation on façade walls of residential building and installation of energy efficient joinery).

Within the first phase of this project, € 33,339 was spent for the implementation of EE measures in 93 households in Montenegro.

3. In the past, several units at local government level have continued the realization of subsidy programs for the installation of solar systems in new buildings, by reducing utility fee (fee for utility land) in the amount of 50-200 € per square meter of installed solar panel, depending on the local self-government units. Also it is important to mention the activities of certain local self-government units, e.g. Municipality of Tivat on establishment supporting programs for citizens (interest free loans), in cooperation with commercial banks, with the aim of implementing energy efficiency measures in the households on the municipality territory.

Future activities:

1. Continuation of the program of Energy Efficient Home over the next period. For the purpose of realization of this project in 2019 budget funds were provided in the amount of € 100,000, which are foreseen for the implementation and interest rate subsidy at commercial banks. Plan for the implementation of the program after 2019, has to take into account the following:

- In case GEFF Residential project is started (see below), it is necessary to modify the program Energy Efficient Home in a way that there is no overlap regarding the implementation of EE measures;
- The implementation of support programs aimed at improving energy efficiency in households and other sectors of final energy consumption should be gradually transferred to the Eco-Fund (see measure H.3).

2. Launch of the GEFF-Residential project in Montenegro. Within the EU support, Western Balkan countries have received the funds to support the household sector for the implementation of energy efficiency measures through the Western Balkans Residential Green Economy Financing Facility (GEFF-Residential) project, which is coordinated by EBRD.

In order to implement project in Montenegro, it is necessary that EBRD establish cooperation with commercial banks in Montenegro (one or more), which would be obliged to establish dedicated credit lines for energy efficiency. In the event that citizens realize energy efficiency measures by using funds from these credit lines, they acquire the right to subsidies, from the allocated EU funds, in the amount of 15-30% of the amount of the investment;

Continuation of promotion of the subsidy program for the use of renewable energy sources in other Montenegrin local self-government units according to the possibilities.

Cogeneration: Regulatory framework

Article 14 of Energy Efficiency Directive (EED) stipulates that member countries shall prepare an overall analysis of potential of high-efficiency cogeneration, as well as efficient systems of district heating and conditioning.
Certain activities were initiated in Montenegro in the past with the aim of meeting obligations stemming from Article 14 of EED, which primarily relate to the transposition of basic requirements of this article into the current Energy Law.

In addition, drafts bylaws of the Energy Law which will define in details the application of high efficient cogeneration, district heating and cooling were prepared under the project "Optimal use of energy and natural resources" financed from IPA 2012. The plan is to adopt these documents during 2019.

In terms of strategic framework, it is important to mention that the Energy Development Strategy of Montenegro for 2016-2020 (adopted by the Government in January 2016) has elaborated the issue of high efficient cogeneration and district heating and cooling under specific programs:

- The programme of district heating / cooling by locations - biomass, gas, heat pumps, municipal waste, high efficient cogeneration plants (program No. 10.3.4)
- The programme for developing Study of introducing district heating system in local communities in the municipalities in the north part of Montenegro (Kolašin, Berane, Žabljak and Plužine) as well as in other cities of Montenegro (Nikšić, Bijelo Polje, Cetinje, Podgorica) for the use of biomass or waste heat from industrial processes and implement Projects if studies show their justification (program No. 10.3.5)
- Heating system project for the town Pljevlja (program No. 10.3.6)

The Energy Law, in Article 20, has stipulated the adoption of a special Action Plan for the development and use of district heating and/or cooling and high-efficiency cogeneration, adopted by the Government for a ten-year period.

With the aim of planning the development of district heating and/or cooling sector and also the high-efficiency cogeneration section, in the action plan, the Law obliges the Ministry of Economy to analyze the profitability, taking into account the technical feasibility of different solutions and technologies.

In accordance with legal obligations, in 2016 and 2017 the Ministry of Economy has prepared a study for the evaluation of the potential for the implementation of high-efficient cogeneration, under the project "Development of sustainable use of energy" . Based on this study the Ministry has prepared a Draft Action Plan for the development and use of district heating and/or cooling and high-efficiency cogeneration. The Action plan was finalised and adopted in 2019.

Planned new major projects

Improving efficiency by revitalizing HPP Piva Phase II

The objective of the project is to increase the generation of electricity from the available hydro potential in order to increase the security of the HPP, increase the share of RES in electricity generation and further the improvement of energy efficiency of current hydropower facilities.

Improving efficiency by revitalizing HPP Perucica Phase II

The objective of this project is to increase the production of electricity from the available hydro potential to increase the safety of the HPP plant, increasing the share of RES in the production of electricity and further improving the energy efficiency of existing hydropower facilities.

Improving efficiency by installing energy efficient block transformers T1-T5 - HPP Perucica

The installation of modern transformers with reduced losses directly influences the reduction of transformational losses in the respective power plant and enables more efficient evacuation of electricity to the grid compared to the existing solution, which results in increased production at the power plant threshold.

Improving efficiency through the renovation of small hydropower plants (Rijeka Crnojevica, Podgor, Savnik, Musovica River and Lijeva rijeka).

Target contributions are, as follows:

- Increase the electricity production from available hydro potential
- Improving energy efficiency in existing SHPPs
- Increasing the safety of the SHPP plant,
- Increasing the share of RES in electricity generation and
- Reduction of losses in the distribution network.

Development of the transmission and distribution network and improvement of its operation

This measure has effects primarily in transmission and distribution sector. **Development of decentralized energy production by energy prosumers (producers-consumers)** The overall target is to increase electricity generation from RES and aim for further energy efficiency improvement of power systems through decentralized generation.

NORTH MACEDONIA

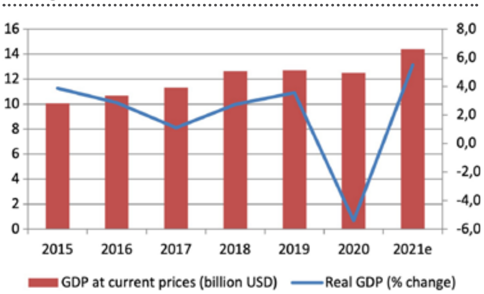
North Macedonia

Economic and Political Background

The pandemic has had a negative impact on overall economic activity in North Macedonia, where average GDP fell by -5.4% in 2020. According to the State Statistical office, North Macedonia's economic output shrank by an estimated 4.5% year-on-year in 2020. Exports of goods and services fell by 10.9% in nominal terms in the year under review, while imports declined by 10.5%. Household final consumption decreased by an estimated 5.6% last year. The unemployment rate declined throughout 2020, reaching 16.1% in the fourth quarter, which is 0.5% lower than last year. IMF estimates that North Macedonia's GDP will expand by 5.5% in 2021, significantly higher than -5.4% in 2020.

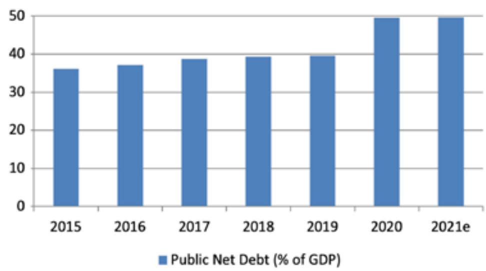
Several major corruption scandals involving high ranking government officials were revealed in the timespan of only several days in March 2021. In the midst of a serious undersupply of vaccines, the government was implicated in severe misconduct in the procurement of vaccines from the Chinese company Sinopharma. Only several days later, the former Secretary General of the government was implicated in corrupt purchases and conflicts of interest dating back to his time in office. Meanwhile, the government was also accused of failing to apply for support funds, resulting in the country receiving zero support from a €530 million EU fund, aimed at supporting the management of the coronavirus.

Figure 5.182 **North Macedonia's GDP and its annual GDP growth**



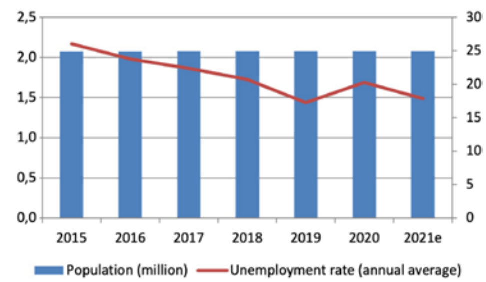
Source: IMF World Energy Outlook (October 2020)

Figure 5.183 **North Macedonia's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.184 **North Macedonia's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

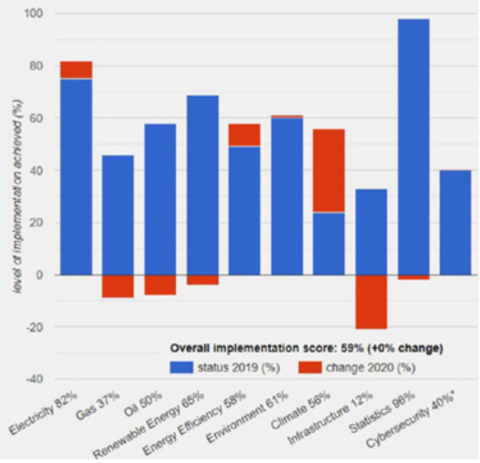
National Energy Policy

North Macedonia, as a candidate country for membership in the EU, faces certain challenges related to the implementation of structural reforms, of which the energy sector is of special significance for the country's overall development. The country has actively participated in regional initiatives, considering that it was the first country in the region to sign a Stabilization and Association Agreement with the EU in 2001. In 2005 it was granted candidate status for EU membership.

With respect to its international commitments referring to the energy sector, North Macedonia signed and ratified the Energy Charter Treaty and the Protocol on Energy Efficiency and Related Environmental Aspects, the Energy Community Treaty (EnCT), the United Nations Framework Convention on Climate Change and the Kyoto Protocol. EnCT represents North

Macedonia's main agreement in force with EU acquis requirements, and extends the acquis to the territory of the country. According to the EnCT, North Macedonia harmonizes its national legislation with the existing legislation of the EU (Acquis Communautaire) on energy, competition, renewable energy sources (RES), energy efficiency (EE), oil reserves, energy statistics, infrastructure, environment and climate. The overall implementation performance for 2019/2020 is presented in Figure 5.185. In addition, it actively participates in all related regional initiatives led by the EU and EnC Secretariat, among which the Western Balkan 6 Initiative (WB6) on establishing a Regional Electricity Market and Sustainability Charter, as well as the EU4Energy Governance and the Energy infrastructure and donor initiatives[1].

Figure 5.185 **Level of implementation of EnCT legislation in 2019/2020 (status: 1 November 2020)**



*2020 first assessment year

Source: Calculated and compiled by the Energy Community Secretariat [2]

The strategic commitments in the energy sector, currently limited to the requirements of the Third package for electricity and gas markets (TPEGM), have been incorporated in the Energy Law adopted in 2018[3]. The Law sets a legal framework for the domestic energy sector, including electricity, gas, renewable sources, oil and security of supply, as well as respective secondary legislation. The new Energy Efficiency Law[4], transposing the EU Energy Efficiency Directive, Energy Performance of Buildings Directive, Regulation on Labelling of energy related products, and Directive on Eco-design of energy related products, was adopted in February 2020. In addition, in the fields of electricity and natural gas, adoption of the acquis from the EU Network Codes (NCs) including the NC on wholesale energy market integrity and transparency is progressing in accordance to the schedule established by the EnCT. The Government has adopted several strategic documents over the past years that define the country's national energy policy. Among those are the Strategy for Energy Development until 2040[5], the Strategy on use of renewable sources until 2020[6], the Strategy for Improvement of the Energy Efficiency until 2020[7], the Action Plan on use of renewable sources until 2025 with a vision until 2030[8], the Third National Energy Efficiency Action Plan until 2020 (3rd NEEAP)[9], the Programme for the promotion of renewable sources and energy efficiency in households for 2018[10] and the same Programme for 2019[11]. In October 2020, North Macedonia became the first ever EnC Contracting Party submitting its draft integrated National Energy and Climate Plan (NECP) to the EnC Secretariat.

1 https://www.energy-community.org/implementation/North_Macedonia.html
2 https://www.energy-community.org/implementation/North_Macedonia.html
3 Energy Law, Official Gazette of the Republic of North Macedonia, No. 96/18 and No. 96/19, [Online]. Available only in local language: http://www.erc.org.mk/pages.aspx?id=8
4 Energy Efficiency Law, Official Gazette of the Republic of North Macedonia, No. 32/20, [Online]. Available only in local language: http://www.economy.gov.mk/doc/2766
5 Strategy for Energy Development until 2040, Official Gazzete of North Macedonia No. 25/20, [Online]. Available: http://www.economy.gov.mk/Upload/Documents/Adopted%20Energy%20Development%20Strategy_EN.pdf
6 Strategy on use of renewable sources until 2020, Official Gazzete of North Macedonia, No. 125/2010, [Online]. Available: http://www.economy.gov.mk/Upload/Documents/Strategy_for_utilizationa_RES.pdf
7 Strategy for Improvement of the Energy Efficiency until 2020, Official Gazzete of North Macedonia, No. 143/2010, [Online]. Available: http://www.economy.gov.mk/Upload/Documents/Strategy%20for%20IEE%20[OG%20143-2010](1).pdf
8 Action Plan on use of renewable sources until 2025 with a vision until 2030, [Online]. Available only in local language: http://www.economy.gov.mk/docs/strategii
9 https://www.energy-community.org/implementation/North_Macedonia.html
10 Programme for promotion of renewable energy sources and energy efficiency in households for 2018, Official Gazzete of North Macedonia, No. 17/18, [Online]. Available only in local language: http://www.economy.gov.mk/doc/2370
11 Programme for promotion of renewable energy sources and energy efficiency in households for 2019, Official Gazzete of North Macedonia, No. 15/19, [Online]. Available only in local language: http://www.economy.gov.mk/doc/2589

Governmental institutions

The Government / Ministry of Economy

The Ministry of Economy (MoE)[12] is in charge of the country's energy sector on behalf of the Government. The main energy related tasks in the Ministry are strategic planning, development of relevant legislation and implementation of energy policy. This includes the policies for liberalization of internal energy markets, EE and RES, as well as the use of new technologies. MoE is responsible for the preparation of the respective primary but also of the secondary legislation, collecting relevant data about the energy production, supply, demand and preparation of the Annual Energy Balance. MoE oversees the development of the energy sector, particularly the increase of EE and incentives for the wider use of RES, competitiveness, secure energy supply and environmental protection.

To achieve these objectives, MoE has developed cooperation with the National Academy of Sciences and Arts, especially the Research Centre for Energy, Informatics and Materials, as well as with the University Ss. Cyril and Methodius and other state and private universities. Within the EE field, MoE cooperates with the Ministry of Environment and Physical Planning, the Ministry of Finance, the Ministry of Transport and Communications and the Energy Agency.

The Energy Agency

The Energy Agency of North Macedonia has been formed for the purpose of providing support to the Government in the implementation of the energy policy. A growing number of NGOs are also involved in energy issues and related environmental problems.

The Energy Regulatory Commission

The state regulatory authority which has competences over the whole energy sector is the Energy and Water Services Regulatory Commission (ERC)[13]. ERC became operational in 2003 and it was empowered to regulate the sector and monitor the energy markets. According to the Energy Law, the Board of ERC consists of five commissioners appointed by the Parliament. The ERC budget, as well as its Annual Report, is also subject to parliamentary approval. Within the framework of authorities given by the Energy Law, the ERC is independent in its operation and decision-making process.

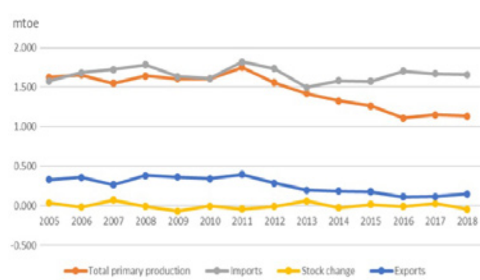
The current competences of ERC are in compliance with the TPEGM.ERC is a member of the Energy Community Regulatory Board (ECRB), Energy Regulators Regional Association (ERRA) and European Water Regulators (WAREG), and observer in the Council of European Energy Regulators (CEER). In July 2019, ERC applied for participation in the working groups of the Energy Regulatory Cooperation Agency (ACER).

Energy Demand and Supply

National energy demand and supply, energy dependency and energy mix

The national primary energy demand and supply between 2005 and 2018 are presented in Figure 5.186. The graph specifically shows data on production, net import and net export of primary energy, as well as reserves, the sums of which coincide with the total consumption of primary energy (gross inland consumption).

Figure 5.186 **Production of primary energy, net imports, net exports and variations of reserves in North Macedonia, during 2005 - 2018**



Source: Information collected from the official page of the State Statistical Office

12 Ministry of Economy of North Macedonia, http://www.economy.gov.mk/Home?lang=2
13 Energy Regulatory Commission of the North Macedonia, http://www.erc.org.mk/DefaultEn.asp

The import of primary energy shows a slight increase since 2005, attaining a share of 63.8% in the gross inland consumption in 2018[14]. However, its importance is highlighted by the decreasing total primary production in recent years. This situation places North Macedonia within the group of countries that are highly dependent on imports. The State Statistical Office calculates the energy dependency as a key energy indicator. Its development over the past few years is given in Table 5.148.

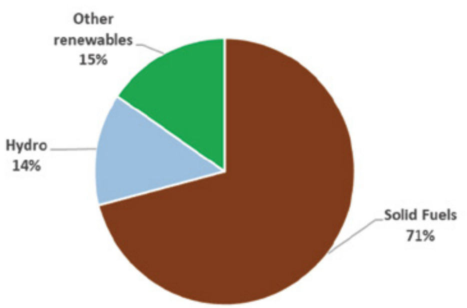
Table 5.148 **Energy dependency in North Macedonia, 2015 - 2018**

2018	58.06 %	preliminary data
2017	56.76 %	definitive data
2016	59.00 %	definitive data
2015	52.09 %	definitive data

Source: Information collected from the official page of the State Statistical Office

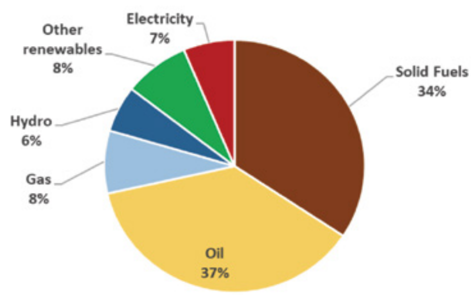
Figures 5.187 and 5.188 illustrate the primary energy mix in North Macedonia, using the State Statistical preliminary data for 2018. Figure 5.189 shows the production of energy by types (primary fuel mix) in mtoe and Figure 5.190 the shares of individual types of fuels in the gross inland consumption. In 2018, the total production of primary energy in North Macedonia was 1.13 mtoe or 43.6 % of the total 2.60 mtoe gross inland consumption.

Figure 5.187 **Energy production by type of fuel of North Macedonia, 2018**



Source: Information collected from the official page of the State Statistical Office

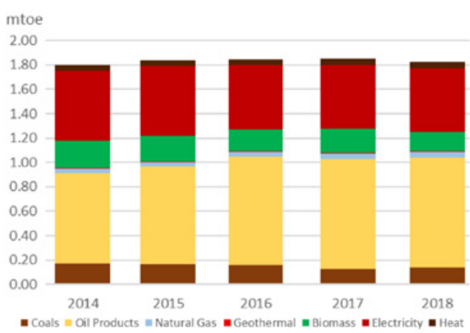
Figure 5.188 **Gross inland consumption by type of fuels in North Macedonia in 2018**



Source: Information collected from the official page of the State Statistical Office

The largest final energy consumers in 2018 were: Transport with 38.2 %, Households with 25.4 % and Industry with 21.6 % (of the available for final consumption). The ratio between final energy consumption and gross inland consumption, which varied from 60 % up to 71.3 % over the last decade, was 71.3 % in 2018. In the final energy consumption of 1.85 mtoe, in 2018, as it is presented in Figure 5.91 and Figure 5.192 the biggest share belongs to petroleum products (49%) and electricity (29%).

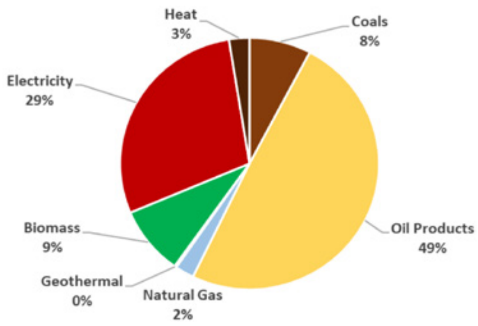
Figure 5.189 **Consumption of final energy by type of fuels in North Macedonia, during 2014 - 2018**



Source: Information collected from the official page of the State Statistical Office

[14] State Statistical Office of North Macedonia, Energy, http://www.stat.gov.mk/PrikaziSoopstenie_en.aspx?rbrtxt=64

Figure 5.190 **Share of individual type of fuels in the consumption of final energy in North Macedonia**

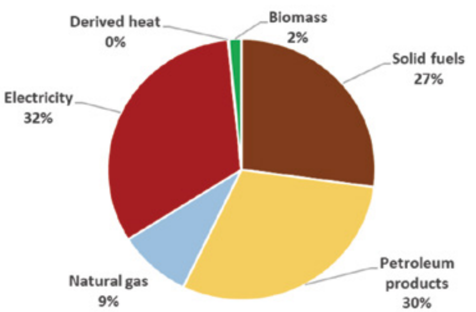


Source: Information collected from the official page of the State Statistical Office

A brief analysis of the data presented draws our attention to the unfavourably small contribution of natural gas in the final energy consumption against the high consumption of electricity. The main contributor to this fact is the consumption of the metal melting industry of the country.

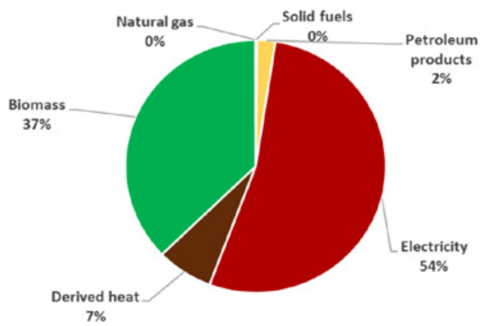
The contributions of the individual fuels in the final energy consumption of industry and households in 2018 is given in Figure 5.191 and Figure 5.192, respectively[15]. One further unfavourable observation in this respect (because of the low efficiency factors involved) is that households largely use electricity for heating purposes.

Figure 5.191 **Final energy consumption in industry by type of fuel, 2018**



Source: Information collected from the official page of the State Statistical Office

Figure 5.192 **Final energy consumption in households by type of fuel, 2018**



Source: Information collected from the official page of the State Statistical Office

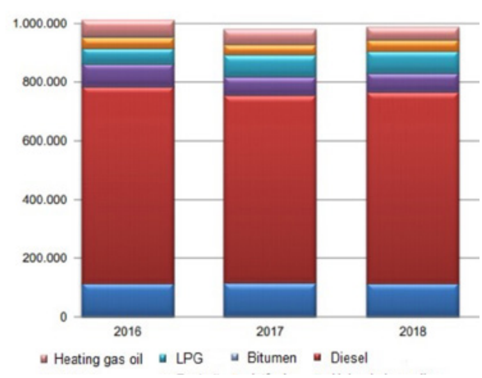
The Energy Market

Oil and Petroleum Products

Oil Supply and Demand

On the basis of the data presented in ERC's Annual Reports 2016 – 2018, the total imported quantities of oil in North Macedonia in 2018 were 0.988 mt, which is about the same as the imported products of oil derivatives in 2017 (0.981 Mt) and 2016 (1.010 mt) (Figure 5.193).

Figure 5.193 **Import of oil derivatives in North Macedonia for 2016, 2017 and 2018 (tons/annually)**

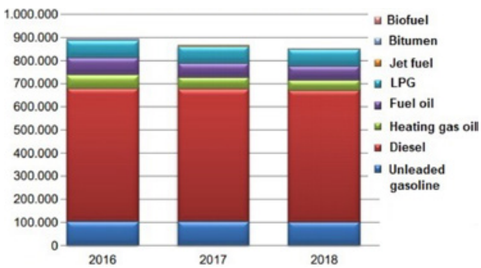


Source: ERC Annual Reports 2016 - 2018

15 http://www.stat.gov.mk/PrikaziSoopstenie_en.aspx?rbrtxt=64

In 2018 the largest import was diesel fuel, 66% of the total import, next are unleaded gasoline types with 11.45%, LPG with 7.39%, fuel oil with 6.65%, heating gas oil with 4.45%, jet fuel with 3.98% and a small percentage of biogas fuel. Oil derivatives were imported from 18 countries, whereby the majority from neighbouring countries: from Greece with 80.31%, Bulgaria with 11.80%, Serbia with 3.46% and Albania with 1.43%. The export of oil derivatives in 2018 was 0.140 mt, which is a small increase from 0.117 mt in 2017. In 2018 there were 0.852 mt of oil derivatives sold at the domestic market, which represents a small decrease compared to previous years, as shown in Figure 5.194.

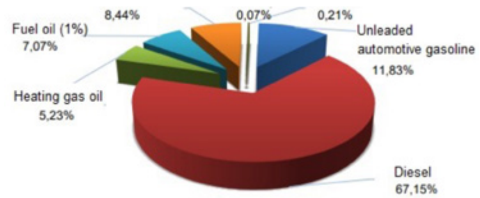
Figure 5.194 **Sale of oil derivatives in North Macedonia in 2016, 2017 and 2018**



Source: ERC Annual Reports 2016 - 2018

Figure 5.195 presents the share of oil derivatives in the total domestic consumption of oil derivatives in 2018, which in 2018 was dominated by diesel fuels. The largest consumers of petroleum products in 2018 were transport with 0.701 mt and industry with 0.129 mt.

Figure 5.195 **Share of oil derivatives in the total domestic consumption of oil derivatives in 2018**



Source: ERC Annual Reports 2016 - 2018

Oil Imports / Dependence, and Security of Supply

North Macedonia is 100% reliant on the import of petroleum products since 2013 and it does not have any confirmed commercial crude oil reserves. The import takes place by road from the surrounding countries, guaranteeing diversified supply sources and security of supply. Like other countries, North Macedonia is obliged to maintain petroleum products reserves in the size that corresponds to no less than 90 days of average daily net imports, or 61 days of average daily consumption, whichever is greater. In 2018, the oil stock corresponded to 65 days, a 5 day decrease from 2017 reserves.

The government has transposed the Directive 2009/119/EC on compulsory oil reserves in the national Law on Compulsory Oil Reserves[16] and has prepared all requested secondary legislation. The Compulsory Oil Reserves Agency is responsible for the establishment, maintenance, storage and sale of compulsory oil and petroleum products reserves. However, the application of the new legislation has been postponed for 1 January 2021, while the compulsory oil reserve goals are to be met by 31 December 2022. According to the Action Plan[17]. North Macedonia aims to hold 70% of required reserves in the country and 30% in EU countries.

Upstream Sector- Domestic Production and Exploration

The oil sector in North Macedonia currently consists of wholesale trade in oil and petroleum products and biofuels, storage and trade of oil and petroleum products as well as retail trading in petroleum products and biofuel. The upstream sector practically does not exist. Possible petroleum plays in the eastern part of the country are mentioned, but exploration has not started yet.

Downstream and Midstream Sectors Infrastructure

The only oil refinery in North Macedonia is OKTA[18] in Skopje. Its majority shareholders

[16] Law on Compulsory Oil Reserves, Official Gazette No.144/2014, 178/2014, 199/2015, 197/17, 7/19 and 275/19
[17] Strategy for Energy Development until 2040, Official Gazette of North Macedonia No. 25/20, [Online]. Available: http://www.economy.gov.mk/Upload/Documents/Adopted%20Energy%20Development%20Strategy_EN.pdf

are Hellenic Petroleum Group. The average capacity of OKTA is 2.5 Mt/year, or 5,480 bbl/day. The maximum production of the refinery was 1.36 Mt petroleum products in 1988. The total storage capacity of OKTA is about 380,000 m^3. [19]

The installations of OKTA are connected with the Hellenic Petroleum refinery in Thessaloniki through a 213.5 km pipeline with capacity of 2.5 Mt/year. The pipeline operator is Vardax SA, a company whose major shareholder is Hellenic Petroleum Group, while the government of North Macedonia retains 20% of shares. The OKTA refinery stopped production in January 2013, because of unfavourable conditions in the international oil market. However, now it is the biggest importer and trader of petroleum products in the country. Private company Makpetrol from Skopje possesses the biggest biodiesel refinery in the country, with a capacity of 0.03 Mt/year. The refinery started operation in 2007 and it uses unrefined oil from oil rape seed[20]. In addition, there are three very small biodiesel refineries.

At the end of 2018, there were approximately 330 petrol stations in North Macedonia. Makpetrol owns 127 of these, Lukoil Makedonija 30 and OKTA 26 stations, while the remaining 147 petrol stations are privately owned by several domestic small companies[21]. The prevailing practice is that companies which possess petrol stations also participate in the wholesale market of petroleum products. The total storage capacity for oil and petroleum products in North Macedonia is approximately 382,000 m3. The biggest contributors in this respect are capacities provided by the OKTA refinery, Makpetrol and Lukoil Makedonija, as well as, the State Stock Reserves. However, the new Energy Development Strategy states that the storage condition and purpose could be improved: "Major concern is the condition of the storage units and their applicability for compulsory oil stocks. In addition, certain part of these capacities is used by traders of petroleum products for their operational reserves as obliged by the Energy Law."[22]

Planned New Projects

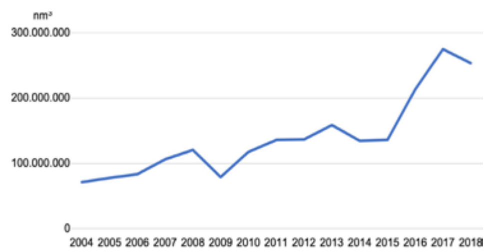
The new Energy Development Strategy has projected growing consumption of petroleum products in all considered scenarios, which would create a need for larger volumes of storage capacities in future. Therefore, the main recommendation is that the country should ensure availability of necessary infrastructure for stock keeping via Action Plan. The Action Plan should define the dynamics of formation of reserves until 31 December 2022, necessary storage volumes per product, location of storage capacities, roadmap to achieving necessary storage capacities, and financing options considering the impact on the final consumers.[23]

Natural Gas

NG Supply and Demand (in bcm)

According to the data of the State Statistical Office and ERC, the total supply/imports of natural gas in North Macedonia rapidly increased during the last few years, as shown in Figure 5.196 reached 0.215 bcm in 2016, 0.276 bcm in 2017 and 0.255 bcm in 2018. The monthly quantities of supply/imports in 2016, 2017 and 2018 are presented in Figure 5.197.

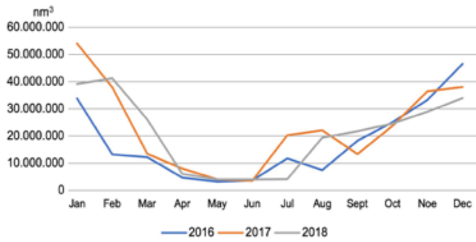
Figure 5.196 **Supply/import of natural gas in the period 2004 - 2018**



Source: ERC

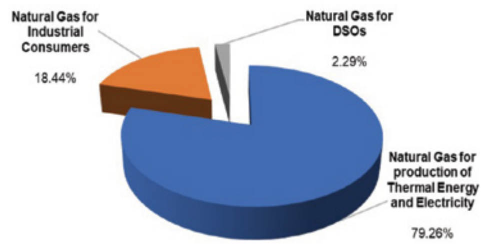
[18] http://www.bloomberg.com/research/stocks/private/snapshot.asp?privcapId=127486542
[19] ERC, Annual Report 2018, [Online]. Available: https://www.erc.org.mk/pages_en.aspx?id=98
[20] ERC, Annual Report 2018, [Online]. Available: https://www.erc.org.mk/pages_en.aspx?id=98
[21] ERC, Annual Report 2018, [Online]. Available: https://www.erc.org.mk/pages_en.aspx?id=98
[22] Strategy for Energy Development until 2040, Official Gazette of North Macedonia No. 25/20, [Online]. Available: http://www.economy.gov.mk/Upload/Documents/Adopted%20Energy%20Development%20Strategy_EN.pdf
[23] Strategy for Energy Development until 2040, Official Gazette of North Macedonia No. 25/20, [Online]. Available: http://www.economy.gov.mk/Upload/Documents/Adopted%20Energy%20Development%20Strategy_EN.pdf

Figure 5.197 **Monthly supply/import of natural gas in 2016, 2017 and 2018**



Source: ERC

Figure 5.198 **Consumption of natural gas by consumer type in 2018**



Source: ERC

As shown in Figure 5.197, the largest consumption of natural gas occurs during the winter months, which is expected considering that natural gas is mostly used for production of thermal energy. During July and August there is a consumption deflection which is due to the operation of CHPP TE-TO, followed by significant increase in the winter period when TE-TO and few smaller CHPP operate in full capacity. The industrial consumers which are using natural gas for their processes and operate all year round define the minimum consumption.

Natural gas consumption in North Macedonia is dominated by combined heat and power production plants and thermal power plants. Their portion in the final natural gas consumption for 2018 was 79,26%. Next are the industrial consumers with 18,44% market share, where the dominant role belongs to the metal industry. At the end are the distribution companies with a share of 2,29% (Figure 5.198).

NG Imports (in bcm), Dependence (%)

North Macedonia is 100% dependent on natural gas imports. Almost the entire supply of gas is imported from Russia through the only entry point at the Bulgarian border. The distribution network in the city of Strumica is not connected with the transmission network and supply is ensured by truck transport of compressed natural gas (CNG) from Bulgaria.

Domestic Production and Exploration

There is neither domestic gas production nor on going gas exploration in the country.

Infrastructure (Pipelines, Storage)

The international Corridor 8 is the most significant import infrastructure, entering the country in Deve Bair. The national master pipeline, from Deve Bair, is extended further to Kriva Palanka, Kratovo, Kumanovo and Skopje (bold blue line in Map 5.49). Its total length is about 98 km and its capacity is 0.8 bcm/year,

Map 5.49 **Existing (in bold) and planned natural gas infrastructure in North Macedonia**

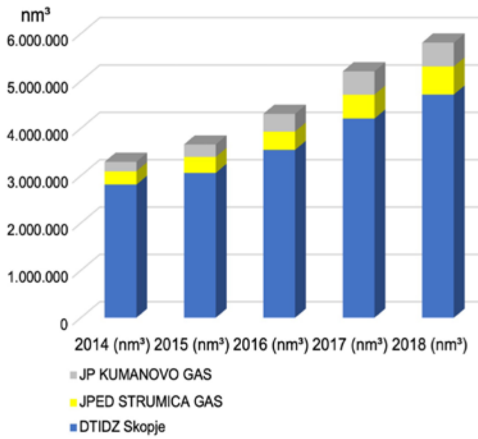
Source: ERC, Annual Report 2018

with possibility for upgrade up to 1.2 bcm/year. Only up to 80% of the existing capacity is used during some winter days, while the daily utilization in the summer months is very low and ranges from 5% to 15%.

In North Macedonia, there are three developed distribution systems for natural gas:
- Town of Strumica, with a length of 28.50 km
- Town of Kumanovo, with a length of 13.14 km
- Technology-Industrial Development Zone (DTIDZ) of Skopje, with a length of 5.20 km.

The natural gas distribution systems are constantly being developed and upgraded. Distributed natural gas volume in their systems is minor, although there is noticeable ongoing growth. The largest portion of distributed gas is in the DTIDZ where there are several industrial consumers using natural gas in the production processes, as well as for heating. A breakdown of distributed natural gas by systems in the period 2014 - 2018 is given in Figure 5.199.

Figure 5.199 **Natural gas quantities in the distribution systems by years and distribution companies**



Source: ERC, Annual Report 2018

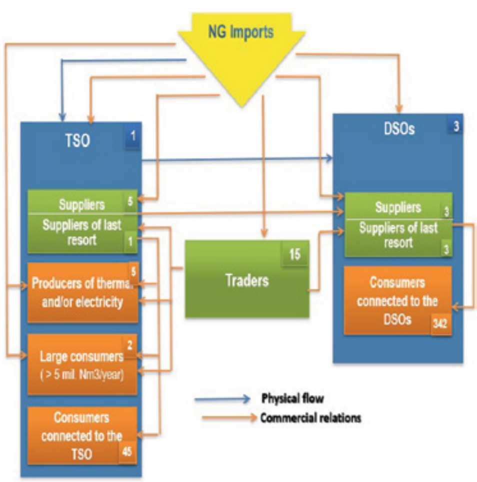
At this stage of gasification in the city of Skopje, there is practically no distribution network. Several existing customers, which are the largest consumers of natural gas in the country, are directly connected to the transmission network. However, there are plans and activities for Skopje's distribution network development.

Domestic Gas Market

The natural gas market is governed by the Energy Law of 2018, which essentially transposes the TPEGM. The corresponding secondary legislation is also in place and greatly implemented, with an exception of ownership unbundling and certification of the Natural Gas TSO, GA-MA[24]. The certification is frozen by a long-lasting dispute on the majority ownership over the gas transmission system between the Government and Makpetrol, who currently both own 50% of shares in GA-MA.

The natural gas market in North Macedonia is fully liberalized as of 01 January 2015. Since then, no natural gas disruptions have been noticed. The structure of the market is presented in Figure 5.200.

Figure 5.200 **Overview of the natural gas market in North Macedonia in 2018**

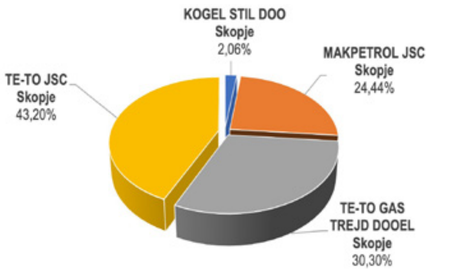


Source: ERC, Annual Report 2018

The market share of the traders and suppliers in the wholesale natural market is displayed in Figure 5.201, while the shares in the retail market can be observed in Figure 5.202.

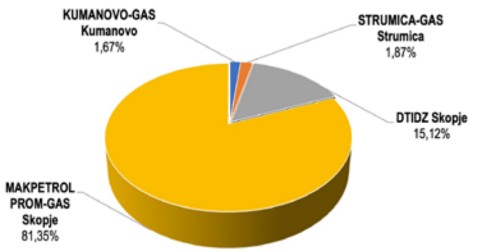
[24] http://www.gama.com.mk/Default.aspx

Figure 5.201 **Market share of traders/suppliers at the wholesale natural gas market in 2018**



Source: ERC, Annual Report 2018

Figure 5.202 **Market share of the suppliers at the retail natural gas market for 2018**



Source: ERC, Annual Report 2018

Makpetol Prom-Gas supplies natural gas to consumers connected to the gas transmission system, while DTIDZ Skopje, Kumanovo Gas and Strumica Gas supply natural gas to consumers of the gas distribution systems respectively. DTRIZ Skopje and Kumanovo Gas purchase natural gas from Makpetol Prom-Gas.[25]

National NG Policy –Strategic Plan

Natural gas is expected to play an important role in replacing coal and as a bridge fuel to 2050. There is an ambitious gasification plan, which includes interconnections with Greece and other countries. As projected by the Energy Development Strategy, the overall consumption of natural gas will constantly increase in the long term, with average annual rate of 3.6%-4.1% depending on the success of implementing EE and RES measures[26].

In order to meet these requirements, the Government has developed a very ambitious national strategic plan for natural gas. The strategic plan is twofold and includes:

- Connection of North Macedonia to major international gas corridors;
- Development of national transmission and distribution grids.

The planned development of the national transmission network for natural gas complies with the expected consumption needs in particular parts of the country. Some of the smaller towns in the country are envisaged to be supplied through so called "virtual pipelines". The expansion of the gas network is to be financed through the State Budget and EIB and EBRD credit lines. The state-owned JSC National Energy Resources (NER)[27] is in charge of the above projects.

Planned new projects

The interconnection with Greece, which is on the Projects of Mutual Interest (PMI) list [28] and is expected to be completed by 2022, is identified as the key project that will diversify supply. It will connect North Macedonia to the Trans Adriatic Pipeline (TAP) which brings natural gas from the Caspian region to Europe. In addition, NER is involved in the Central and South East Gas Connectivity (CESEC) initiative. Under it, a Memorandum of Understanding (MoU) was signed in Dubrovnik in 2015 that includes projects for interconnectors between North Macedonia, Greece and Bulgaria. There is also potential for five other interconnections with Serbia, Albania, Kosovo, Bulgaria and Greece (link with Bitola). The interconnector with Serbia is in the current PECI/PMI list too.

As reported by ERC, there are also several magistral pipelines under construction, with total length of 204 km (phase I), and due to be completed by the end of 2020. Those are:

- Stip – Negotino – Bitola (81% completed by the end of 2019); and
- Skopje – Tetovo – Gostivar (57% completed by the end of 2019).

[25] ERC, Annual Report 2018
[26] Strategy for Energy Development in North Macedonia for the period until 2040
[27] http://mer.com.mk/en-US
[28] https://www.energy-community.org/regionalinitiatives/infrastructure/selection.html

In phase II of the development of national magistral network, NER plans to construct the following pipelines:

- Magistral gas pipeline, section Gostivar – Kichevo (due in 2022),
- Magistral gas pipeline, section Kichevo - Ohrid (due in 2025).

Furthermore, in order to provide development and renewal of the natural gas transmission system, as well as development and expansion of the gas transmission pipeline grid, NER has also planed the following activities, for the period from 2019 to 2023:

- Expansion of the city gas pipeline network in Skopje for the connection of new consumers;
- Completing the gas pipeline ring along with distribution lines for connecting interested consumers in the City of Skopje,
- Construction of a new connection to the magistral gas pipeline for the needs of CHPP TE-TO in order to increase its operating efficiency;
- Implementation of SCADA system over the gas transmission network for measurements and detection of losses.

Solid Fuels

Supply and consumption

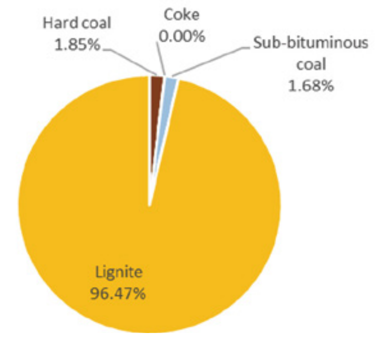
According to the State Statistical Office data, the balance of solid fuels including production, import, stock change and export, the sums of which coincide with the total consumption of primary energy (gross inland consumption) during the period 2015 - 2018 is presented in Figure 5.203.

Figure 5.203 **Production of solid fuels, net imports, net exports and variations of reserves in North Macedonia, during 2015 - 2018**

Source: Information collected from the official page of the State Statistical Office

The production consists only of lignite with its rather low calorific value and a decrease of production over recent years is evident. The total primary production of lignite in 2018 was 4.994 mt and it was almost completely (95%) used for electricity production in TPPs. The other types of fuels (hard coal, coke and sub-bituminous coal) composing the gross inland consumption (4.911 mt in 2018) regularly come from import. However, their shares are very small in comparison to the share of lignite (Figure 5.204).

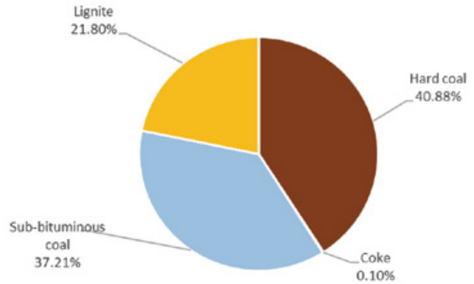
Figure 5.204 **Gross inland consumption of solid fuels by type in 2018**



Source: Information collected from the official page of the State Statistical Office

In 2018, after using lignite for electricity production and filling a stock gap of lignite, about 0.221 mt (4.5% of gross inland consumption) remained available for final consumption. The shares of individual types of solid fuel in the final consumption are shown in Figure 5.205. The biggest final consumer of solid fuels with 0.207 mt was the industrial sector.

Figure 5.205 **Solid fuels available for final consumption of by type in 2018**



Source: Information collected from the official page of the State Statistical Office

Local production and exploration

Out of all fossil fuels, North Macedonia disposes and exploits only low calorific coal - lignite. All other fossil fuels, such hard coal and sub-bituminous coal, are provided through imports. Existing lignite mines in the country are divided into two groups, according to the intended use: (a) production of electricity, which includes surface mines owned by TPPs of the biggest electricity production company in the country (state owned) Power Plants of North Macedonia (ESM). These are Suvodol, Suvodol-Low Basin (LB), Brod-Gneotino (TPP Bitola) and Oslomej (TPP Oslomej); and (b) retail trade and consumption, consisting of surface mines BRIK Berovo and Drimkol-lignite, which are minor.

Deposits

The rest of lignite deposits in North Macedonia consist of the following sites: Zivojno, Mariovo, Popovjani, Negotino, Lavci-Resen, Pancharevo-Pehchevo, Zvegor-Delchevo and Priskupshtina. Table 5.149 provides information on the exploitation reserves of these deposits in 2014. The only important deposits are Mariovo and Negotino, whose thermal capacity accounts for 28% and 18% of total, respectively.[29]

Since 2014, there have not been any important developments in the opening of new mines and state deposits, except that the mines owned by ESM are continuously exploited in the meantime. As a result of this exploitation, Oslomej mine is nearly depleted of its resources and mines of TPP Bitola (Suvodol, Suvodol – Low Basin (LB), Brod-Gneotino) are sufficient to provide life to TPP Bitola up to 2030.

Table 5.149 **Assumed deposits of lignite available for exploitation in North Macedonia in 2014**

Deposit	Exploitation reserves	Low Calorific	Available capacity	Thermal	Annual exploitation
	[mt]	[kJ/kg]	[PJ]	[%]	[mt]
Suvodol	6	7,700	46	2.7	4.5
Brod-Gneotino	23	6,800	156	9.3	2
Suvodol LB	48	8,300	398	23.7	3
Oslomej West	0.7	7,600	5	0.3	1.1
Zivojno	21	7,450	156	9.3	2
Mariovo	61	7,654	467	27.8	2
Negotino*	38	8,000	304	18.1	
Popovjani*	9	7,600	68	4.1	1.1
Lavci - Resen*	15	5,300	80	4.7	
Pancharevo - Pehchevo*	20	7,230	145	7.4	
Zvegor - Delchevo*	12	8,720	105	5.4	
Brik – Berovo	1	8,000	8	0.5	
Drimkol -	1	10,300	10	0.6	
Priskupshtina					
TOTAL	256	7,622**	1,949	100	

* Insufficiently explored ** Mean value
Source: Draft Strategy for Energy Development in North Macedonia for the period until 2035

Coal imports

As reported by the State Statistical Office, a total of 0.214 mt of coal was imported in North Macedonia in 2018, of which: 0.101 mt hard coal, 0.0003 mt of coke, 0.092 mt of sub-bituminous coal and 0.020 mt of lignite. As it can be observed in Table 5.149, the imports are rather steady in the past years and there are no prospects than increasing in the near future.

Planned new projects

With the Program for implementation of the Strategy for Energy Development in North Macedonia for the period 2013 – 2017 there were several lignite projects proposed (mainly in support of operation of TPP Bitola). A new program is currently under preparation by the Ministry of Economy of North Macedonia. However, the new Energy Development Strategy of 2020 completely changes considerations on energy sector development by focusing on possibilities for decarbonization of the energy sector and transition to green

[29] MANU, Draft Strategy for Energy Development in North Macedonia for the period until 2035

energy by decommissioning of existing lignite TPPs in near future. Therefore, at this stage, investments in new lignite mines look rather uncertain. The only lignite mine opening project, as considered in the Reference scenario of the new Energy Strategy, is Zivojno. This site is located near TPP Bitola and according to ESM's 5-year investment plan 2018-2022, the commissioning of new Zivojno mine could extend the coal supply to TPP Bitola for about 10.6 years.

Electricity

The reform of the North Macedonian electricity sector continued towards fulfilling the requirements of the Third Package for Electricity and Gas Markets (TPEGM) with the adoption of the new Energy Law in 2018[30]. The EnC represents the main agreement in force with EU acquis requirements and following decisions of the Permanent High-Level Group of the EnC, all Contracting Parties are obliged to transpose the acquis from some of the EU Network Codes (NCs). This specifically includes connection NCs and the NC on wholesale energy market integrity and transparency. ERC, introduced above, is the National Regulatory Authority in charge of the electricity sector.

Most of the incumbent generation is concentrated in the single state-owned company JSC Power Plants of North Macedonia (ESM)[31]. Then, the North Macedonian Electricity Transmission System Operator (MEPSO)[32] owns and operates the high-voltage network. MEPSO founded the Electricity Market Operator of North Macedonia – MEMO in October 2018, which, although it is under its umbrella, is separate from the transmission business. EVN Skopje JSC[33] has 4 daughter companies active in the electricity sector, adhering to unbundling requirements.

Elektrodistribucija is the largest distribution system operator with its network covering 99.9% of the country, EVN Home performs public supplier functions, EVN Supply is active on the open market, and EVN Power Plants owns and operates medium and small hydro power plants with a total capacity of 87.81 MW. Finally, the ESM subsidiary Energetika contains a vertically integrated DSO, which operates on a very limited territory of Skopje's industry complex Zelezarnica. It serves a small number of light industrial and commercial customers, for which it holds a license granted by the ERC.
Besides the Energy Law provisions, North Macedonia's wholesale electricity market is also governed by the current Market Rules. The percentage of market liberalisation in 2018 was 47.26 % according to the ERC. The previous year, this percentage was estimated at 39.75 %, which signifies a solid step towards opening up the market. Supplier switching is another good indicator of market competition. ERC registered 4,344 changes of supplier in 2018, which represents 20.13 % of the total number of consumers on the liberalised market. Furthermore, this is an increase of 36.68 % compared to the previous year (3,299 supplier changes).

The year 2019 was significant for market liberalisation, because the previous stepwise liberalisation plan was abandoned, and all customers became eligible customers on 1 January. The former Supplier for tariff customers[34] in North Macedonia ceased to operate on 1 July 2019, when the newly established suppliers securing the provision of universal service in compliance with the TPEGM and the Energy Law took over. The new regulated suppliers are the universal supplier and the supplier of last resort, and the company to perform these two regulated supply activities is EVN Home, a subsidiary of EVN Skopje JSC, which won the public tender, transparently open for that purpose.

30 Energy Law, Official Gazette of the Republic of North Macedonia, No. 96/18 and No. 96/19, [Online]. Available only in local language: http://www.erc.org.mk/pages.aspx?id=8
31 http://www.elem.com.mk/en/Elem.asp
32 http://www.mepso.com.mk/en-us/Default.aspx
33 http://www.evn.com.mk/
34 Until 1 January 2019, according to the previous Energy Law, tariff customers were only households and small commercial customers with less than 50 employees and less than 10 million Euros annual revenue in the last two fiscal years and which had consumed less than 100 MWh electricity in 2017. The rest of the electricity customers were by Law mandatory sent to the open electricity market, previously.

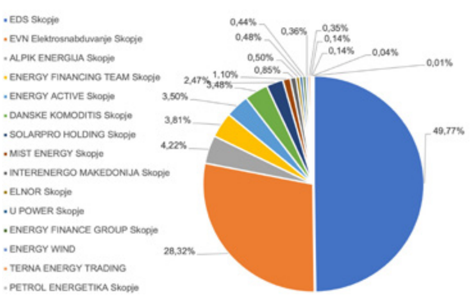
The services of the universal supplier are available for households and small commercial customers with less than 50 employees in the last two fiscal years and less than 2 million Euros annual revenue, who have not selected or have terminated their contract with a supplier on the open market. The universal supplier services can be used for three months at most.

Electricity Supply and Demand

Eligible consumers were able to choose from 18 suppliers and traders in 2018. Their market shares are represented in the Annual Report 2018 of Energy and Water Services Regulatory Commission (ERC).

Energy Delivery Solutions (EDS) has a significant share of the supply and, in addition, it is the responsible party for the balancing market serving multiple producers with a total installed capacity of 320 MW. The supplier is also active in other markets in South Eastern Europe and is a member of the Hungarian Power Exchange. Since 13 April 2018, EDS operates as a subsidiary of the Greek company Public Power Corporation (PPC). The acquisition was reportedly worth 4.8 million Euro.

Figure 5.206 **Market shares of active electricity suppliers in 2018**



Source: ERC, Annual Report 2018

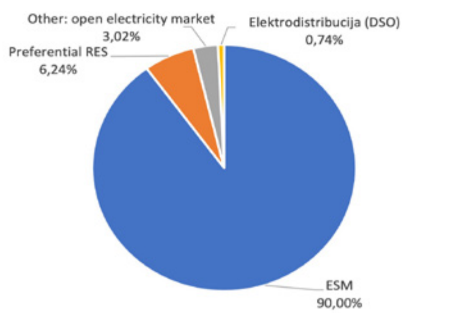
Table 5.150 shows electricity procurement of the largest electricity supplier for household and small consumers in North Macedonia in 2018, according to the ERC report. The data refers to EVN, as it was performing the function of supplier of tariff consumers in 2018. The majority of these customers are expected to remain with EVN and be supplied with electricity by the newly formed EVN Home, therefore it may be relevant to foresee the future operation of the major supplier.

Table 5.150 **Electricity procurement by EVN Macedonia for the purposes of supplying tariff and small consumers in 2018**

Producer/trader	Amount (MWh)	Price (€/MWh)	Value €
JSC ESM	3.484.704	40,37	140.693.035
Preferential RES	241.730	100,14	24.207.120
Elektrodistribucija	28.517	55,71	1.588.724
ALPIK Energy	7.776	62,41	485.336
Danske Commodities Skopje	15.360	50,46	775.129
Energy Financing Team	13.808	70,33	971.140
GEN-I Skopje	45.008	71,46	3.216.246
Green Energy Trading	1.680	43,69	73.401
HSE Mak Energy	7.776	62,43	485.450
Interenergo	24.912	61,66	1.536.090
Total	3.871.270	44,95	174.031.672

Source: ERC, Annual Report 2018

Figure 5.207 **Percentage share of electricity procurement by EVN Skopje JSC for the purposes of supplying tariff and small consumers in 2018**



Source: ERC, Annual Report 2018

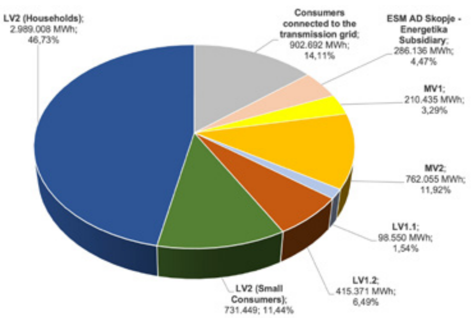
The ERC reports that the total electricity consumption in North Macedonia in 2018 was 6.365 TWh, which is a decrease of 0,19% compared to 2017. Details are presented in Table 5.151 and Figure 5.208.

Table 5.151 **Electricity consumption per consumer category in 2016, 2017 and 2018**

	Consumers	2016 (MWh)	2017 (MWh)	2018 (MWh)	2018/2016 (%)	2018/2017 (%)
1.	Connected to the ransmission grid (110kV)	1,327,568	1,127,163	1,158,327	-12.75	2.76
1.1	Yugohrom Feroalloys	226,969	2,156	1,631	-99.28	-24.35
1.2	USJE Cement Factory	97,432	99,840	102,630	5.33	2.79
1.3	Macedonian Railroads Transport	12,599	12,240	12,500	-0.79	2.12
1.4	TE-TO JSC Skopje (own consumption)	2,749	2,207	2,814	2.34	27.50
1.5	Buchim	119,088	116,246	112,771	-5.30	-2.99
1.6	Feni Industry	425,735	304,895	374,805	-11.96	22.93
1.7	OKTA	6,337	6,076	5,040	-20.47	-17.05
1.8	Kompleks Energetika	215,045	291,404	285,140	32.60	-2.15
1.9	ESM JSC Skopje (mines and own consumption)	217,517	287,973	257,490	18.38	-10.59
1.10	WPP Bogdanci (own consumption)	295	317	367	24.46	15.77
1.11	TPP Negotino (own consumption)	3,801	3,810	3,140	-17.38	-17.58
2.	Losses in the transmission grid	116,080	111,058	125,269	7.92	12.80
3.	Connected to the distribution system	5,127,643	5,250,091	5,206,869	1.55	-0.82
3.1	MV1	145,756	193,204	210,435	44.37	8.92
3.2	MV2	715,720	709,081	762,055	6.47	7.47
3.3	LV1.1	101,209	97,300	98,550	-2.63	1.28
3.4	LV1.2	462,455	419,917	415,371	-10.18	-1.08
3.5	LV2	3,702,504	3,830,590	3,720,457	0.48	-2.88
3.5.1	LV2 (other)	645,049	734,010	731,449	13.39	-0.35
3.5.2	LV2 (households)	3,057,454	3,096,580	2,989,008	-2.24	-3.47
4.	Losses in the distribution system	889,582	893,360	868,549	-2.36	-2.78
5.	Total electricity consumption (1+3)	6,455,211	6,377,254	6,365,196	-1.39	-0.19

Source: ERC, Annual Report 2018

Figure 5.208 **Structure of consumer categories in total electricity consumption in 2018 (in MWh and % share)**



Source: ERC, Annual Report 2018

Compared to 2017, electricity losses in the transmission grid in 2018 increased by 12.8 % due to increased transit. Nevertheless, the losses percentage was 1.8 %, which is sufficiently below the allowed maximum of 3 %. While in the distribution grids, the electricity loss percentage was 14.2 %, which is over the allowed 13.4 %.

Installed Capacity

The electricity generation portfolio of North Macedonia comprises both hydro and thermal production capacities. It also includes one wind farm and a number of smaller RES installations. The main electricity companies are ESM, TETO[35] and EVN Power Plants, while the rest are smaller hydro plants and various RES plants.

ESM is the largest producer in North Macedonia. The total installed capacity of its power plants is 2,076 MW. It owns and operates 49.8 % of the

[35] http://te-to.com.mk/en_US/

thermal power capacity in the country (Bitola 1,2,3 and Oslomej), two CHP plants (Energetika and KOGEL), eight hydro plants and the wind farm at Bogdanci. Its role as regulated power producer will undergo a stepwise downward reduction as prescribed by the new Energy Law. ESM is obliged to offer the following quantities of electricity to the universal supplier:

(1) in 2019 at least 80% of the total annual needs of the supplier;
(2) in 2020 at least 75% of the total annual needs of the supplier;
(3) in 2021 at least 70% of the total annual needs of the supplier;
(4) in 2022 at least 60% of the total annual needs of the supplier;
(5) in 2023 at least 50% of the total annual needs of the supplier;
(6) in 2024 at least 40% of the total annual needs of the supplier;
(7) in 2025 at least 30% of the total annual needs of the supplier.

Furthermore, with the still governing balancing rules, ESM has exclusivity rights to reserve and balancing provision. This will be abandoned very soon with the new balancing rules. However, it is questionable if a real competition will be open in this respect, as besides ESM, the only generator in the country which has technical capabilities for provision of ancillary services is CHPP TE-TO. The largest production capacity is TPP Bitola, located in the south-western part of the country, with 675 MW of installed power capacity. The plant is undergoing a process of modernisation, currently in its third and fourth phase, which include fitting new electrostatic filters and cooling towers (in the stages of procuring materials). It is expected that the project will be completed in the beginning of 2021. TPP Oslomej near Kichevo has an installed capacity of 125 MW. Due to the nearly depleted resources in nearby mines, the plant is awaiting decision on its future, i.e. decommissioning or changing the fuel supply. ESM will make that decision in line with the recommendations from the new Governmental Strategy.

TPP Negotino, with an installed capacity of 210 MW is used exclusively for cold reserves because it uses heavy fuel oil and the production is uneconomical. TETO in Skopje is the largest combined heat and power plant, with an installed capacity of 220 MW for electricity and up to 160 MW for heat production.

The bulk of the hydro power is located in the western part of the country, utilizing the potential of the river basins of Vardar, Crn Drim, Radika and Treska. The Mavrovo Hydro Power System includes three power plants: HPP Vrutok, HPP Raven and HPP Vrben, with total installed capacity of 214 MW and represents one of the largest and the most complex hydro power systems in North Macedonia. HPP Shpilje (84 MW) and HPP Globochica (42 MW) are located in the river basins of Crn Drim and Radika.

Map 5.50 **Location of power plants owned by ESM**

Source: www.elem.com.mk

HPP Kozjak and HPP Sv. Petka, with an installed capacity of 88 MW and 36 MW respectively, make the hydro cascade in the river Treska, near Skopje. HPP Tikves, with an installed capacity of 116 MW, is located in the river basin of Crna Reka, in the central part of the country Finally, the wind farm at Bogdanci with an installed capacity of 38 MW is located in the north-east.

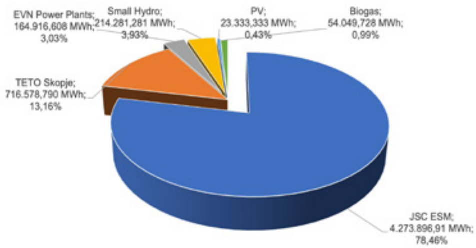
The locations of these larger power plants are shown in Map 5.50. Table 5.152 summarizes electricity generation in 2016, 2017 and 2018, while the information for 2018 is presented in the pie chart in Fig. 5.210.

Table 5.152 **Electricity generation in North Macedonia in 2016, 2017 and 2018**

		Generation (MWh)			2018/2016	2018/2017
		2016	**2017**	**2018**	**% difference**	**% difference**
1.	**JSC ESM**	**4.382.207**	**4.228.861**	**4.273.897**	**-2,47**	**1,06**
1.1	Thermal	2.777.217	3.289.985	2.703.379	-2,66	-17,83
	Bitola 1	594.256	958.037	951.037	60,04	-0,73
	Bitola 2	922.624	1.230.990	762.055	-17,40	-38,09
	Bitola 3	1.229.176	1.026.650	890.506	-27,55	-13,26
	Oslomej	31.161	74.308	99.781	220,21	34,28
1.2	**Hydro**	**1.494.279**	**820.003**	**1.460.297**	**-2,27**	**78,08**
	Globochica	233.234	97.422	232.065	-0,50	138,21
	Kozjak	143.253	71.313	157.805	10,16	121,28
	Sveta Petka	63.114	34.465	67.253	6,56	95,13
	Raven	53.304	39.814	40.567	-23,89	1,89
	Shpilje	354.308	158.369	379.250	7,04	139,47
	Tikvesh	145.593	63.505	153.504	5,43	141,72
	Vrben	54.512	29.477	39.507	-27,53	34,02
	Vrutok	446.961	325.638	390.346	-12,67	19,87
1.3	**CHP**	**1.228**	**8.393**	**12.882**	**949,09**	**53,50**
	ESM Energetika	1.228	8.393	12.882	949,09	53,50
	Kogel	3.697	7.003	0	-100,00	-100,00
1.4	**Wind**	**109.483**	**110.480**	**97.338**	**-11,09**	**-11,90**
	Bogdanci	109.483	110.480	97.338	-11,09	-11,90
2.	**TETO JSC**	**550.119**	**794.654**	**716.579**	**30,26**	**-9,83**
	TETO	550.119	794.654	716.579	30,26	-9,83
3.	**EVN Power Plants**	**184.902**	**119.826**	**164.917**	**-10,81**	**37,63**
	Babuna	1.308	996	1.379	5,43	38,50
	Belica	620	297	560	-9,58	88,49
	Doshnica	21.697	21.458	22.317	2,86	4,00
	Kalimanci	42.049	14.342	31.665	-24,69	120,79
	Matka	35.879	21.782	36.721	2,35	68,58

Source: ERC, Annual Report 2018

Figure 5.209 **Electricity generation in North Macedonia in 2018**



Source: ERC, Annual Report 2018

Planned New Capacity – Investments

According to the latest ECR report the following investment were approved for ESM in 2017 and 2018:

Table 5.153 **ERC approved investment for ESM (in MKD)**

Power Plant	**2018**	**2017**
Hydro power plants	453.794.181	153.927.152
REK Bitola total	3.109.969.437	2.955.263.064
Thermal power plant Bitola	1.071.469.437	638.034.064
Mines Bitola	2.038.500.000	2.317.229.000
REK Oslomej total	737.748.114	52.819.865
Thermal power plant Oslomej	737.748.114	52.819.865
Mine Oslomej	0	0
Total	4.301.511.732	3.162.010.081

Source: ERC, Annual Report 2018

None of the funds are allocated for capacity expansion, and no such plans have been announced by ESM or private investors. This excludes small hydro plants and RES, which are covered in the next section.

Electricity Imports – Exports

North Macedonia has a relatively high import dependency. Despite the declining consumption, the average share of imports is around 30% of total electricity consumption. Specifically, in 2018, domestic generation supplied 69.02 % of total demand, while 30.98 % was supplied through imports. However, there was a 21.35 % increase in electricity exports in 2018 compared to 2017, and an increase of 136.11 % compared to 2016. The details are summarised in Table 5.154.

Tariffs

In 2018, electricity prices for residential customers and public lighting were regulated, while commercial and agriculture customers could be regulated or liberated depending on their size. The average regulated prices in 2018 excluding additional charges were:

- Residential: 2.19 MKD/kWh or 35.58 €/MWh
- Public lighting: 4.48 MKD/kWh or 72.83 €/MWh
- Regulated 'small' commercial: 6.79 MKD/kWh or 110.36 €/MWh

The average price on the wholesale electricity market in 2018 was 3.46 MKD/kWh, or 56.73 €/MWh, which corresponds to an increase of 14.57 % to the previous year. Furthermore, industrial customers were supplied on the open market with an average price of 3.53 MKD/kWh or 57.36 €/MWh, an increase of 12.42 % compared to 2017. Lastly, the 2018 average price for 'large' commercial customers increased by 23.91 % from 2017, reaching 3.42 MKD/kWh or 55.55 €/MWh.

Table 5.154 **Electricity imports and exports in North Macedonia in 2016, 2017 and 2018**

	Electricity (MWh)			**2018/2016**	**2018/2017**
	2016	**2017**	**2018**	**% difference**	**% difference**
Exports from domestic generation	159.853	311.026	377.423	136,11	21,35
Declared imports	2.190.606	2.293.571	2.297.169	4,86	0,16
Total electricity sold on regulated and open market	7.414.899	7.360.299	7.415.009	0,00	0,74
% participation of imports	29,54	31,16	30,98	-	-

Source: ERC, Annual Report 2018

The information is summarized in Table 5.155. All given prices do not include network tariffs and VAT.

Table 5.155 **Electricity prices per consumers types**

	Consumer type		Price (€/MWh)
1.	**Industrial**		
1.a	Metal industry		
1.b	Building materials industry	Liberalised	57.36
1.c	Other industries in high-voltage		
1.d	Industries in medium voltage		
2.	**Public lighting and others**	Regulated	**72.83**
3.	**Residential**	Regulated	**35.58**
4.	**Commercial**		
4.a	Type I – large consumers	Depends on size	55.55
4.b	Type II – commercial consumers	Depends on size	110.36

Source: ERC, Annual Report 2018

Besides VAT of 18%, the following additional charges applied in 2018:

- Transmission network tariff: 0.2053 mkd/kWh or 3.30 €/MWh
- Elektrodistribucija (DSO) distribution network tariff: 1.4084 mkd/kWh or 23 €/MWh
- ESM Energetika (DSO) distribution network tariff: 0.2258 mkd/kWh or 3.70 €/MWh
- Electricity market organisation and operation tariff: 0.0018 mkd/kWh or 0.03 €/MWh

Cross-Border Interconnections

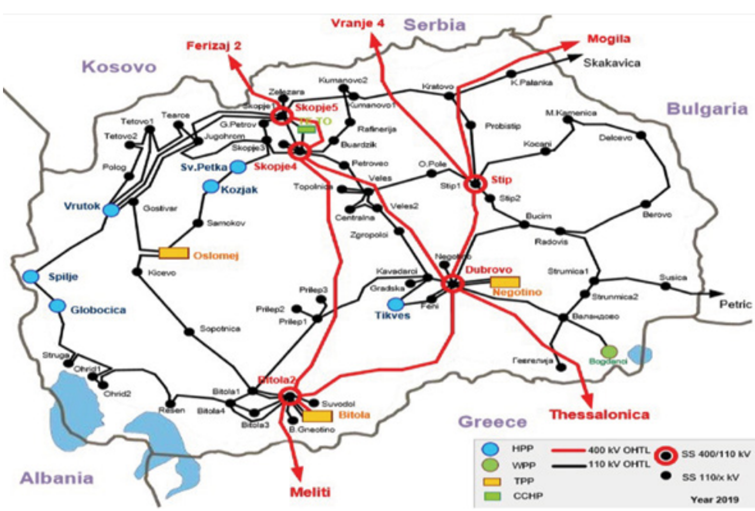
The 400 kV transmission lines are the backbone of the transmission grid in North Macedonia and provide interconnections to the neighbouring power systems. The 110 kV transmission grid is the most outspread one and connects the large hydro power plants, all of the larger populated places, as well as the industrial centres.

Map 5.51 shows the current transmission network with its interconnections.

The 400 kV transmission lines SS Skopje 5 – SS Kosovo B and SS Stip – SS Nis interconnects the north part of the grid to Kosovo and Serbia, respectively. With the Greek electricity system, the interconnection is realized via two 400 kV transmission lines: SS Bitola 2 – SS Florina and SS Dubrovo – SS Thessaloniki. In 2009 the transmission systems of North Macedonia and Bulgaria were synchronously connected, after completing the 400 kV transmission line SS Stip – SS Crvena Mogila.

Transmission rights on interconnectors in North Macedonia are granted in the form of Physical Transmission Rights. The allocation on the borders with Serbia and Bulgaria are carried out bilaterally, while coordinated capacity allocation is performed on the North Macedonian-Greek border by SEE CAO.

Map 5.51 **The Transmission network of the Republic of North Macedonia in 2019**



Source: MEPSO

Planned New Projects

The electricity infrastructure part of Corridor 8 (East-West) will be fully completed by interconnecting the Albanian Power System on the west, after completion of the 400 kV interconnection project Bitola - Ohrid - Elbasan. This project is underway. It includes construction of a new 400 kV line and a new 400/110kV substation in Ohrid. The future topology of the North Macedonian transmission network, according to MEPSO's development plan, is shown in Map 5.52. In general, the transmission grid operates with satisfactory safety, reliability and security parameters. Certain weaknesses of the grid were identified in the Ohrid region related to reactive power and voltage support due to the old topology of the 110 kV grid. It is expected that completion of the project for the new 400/110 kV SS Ohrid will mitigate these issues.

Map 5.52 **Transmission network of the Republic of North Macedonia in 2019**

Source: MEPSO

Renewables

Overview of Sector's Development

The Renewables sector in North Macedonia is also governed by the Energy Law. It prescribes adoption of a new Strategy on Energy Development and Action Plan for Renewables in which the energy policy of North Macedonia for the following 20 years shall be determined, including the potential of RES and necessary measures for support. In the meantime, strategic decisions are based upon the previously adopted Action Plan for RES from 2015[36] and the Action Plan for Amending the Action Plan for RES from 2017[37].

The potential for RES capacity in the country is estimated as part of the Action Plan for RES. It follows the most likely scenario for RES development in North Macedonia, indicating the realistic potential to develop each RES type until 2025. Table 5.156 and Table 5.157 present the realistic potential, and therefore projected RES installed capacity and electricity generation until 2025.

These projections are taken into account in the Decision on the mandatory national targets for RES[38], brought in February 2019, that defines national targets as:

[36] Ministry of Economy of North Macedonia, Action plan for development of renewable energy sources until 2025 with a vision until 2035, Official Gazette of the Republic of North Macedonia, No. 207/15., November 2015.

[37] Ministry of Economy of North Macedonia, Action plan for amending the action plan for development of renewable energy sources until 2025 with a vision until 2035, April 2017, Official Gazette of the Republic of North Macedonia, No. 51/17.

[38] Government of North Macedonia, Decision on the mandatory national targets for renewable energy sources, February 2019, Official Gazette of the Republic of North Macedonia, No. 29/19., Available only in local language

• 23 % RES participation in the total electricity consumption by 2020
• 10 % RES participation in the total electricity consumption in the transport sector by 2020.

Table 5.156 **Historical and potential RES installed capacity in MW in North Macedonia from 2016 until 2025**

Year	2016	2017	2018	2019	2020	2025
Hydro (normalised)	659.5	669.6	683.2	696.9	709.0	866.0
< 1 MW	97.8	107.9	121.5	135.2	147.3	191.1
1 MW–10 MW	97.8	107.9	121.5	135.2	147.3	191.1
> 10 MW	561.7	561.7	561.7	561.7	561.7	674.9
Solar PV	17.4	20.8	22.2	23.6	25.4	35.6
Wind	36.8	36.8	50.0	50.0	50.0	150.0
Biomass	0.0	0.0	1.3	3.0	6.2	10.0
Biogas	6.0	7.0	7.0	7.0	8.0	12.0
Total	720.0	734.0	764.0	781.0	799.0	1,074.0

Source: Action Plan for Amending the Action Plan for RES from 2017

Table 5.157 **Historical and potential RES generation in GWh in North Macedonia from 2016 until 2025**

Year	2016	2017	2018	2019	2020	2025
Hydro (normalised)	1,648.2	1,702.1	1,748.2	1,794.1	1,835.1	2,355.6
< 1 MW	293.2	347.1	393.2	439.2	480.2	628
1 MW–10 MW	293.2	347.1	393.2	439.2	480.2	628
> 10 MW	1,355	1,355	1,355	1,355	1,355	1,727.6
Solar PV	24.3	29.1	31.1	33.1	35.6	49.9
Wind	109.4	110	140	140	140	337.9
Biomass	0.0	0.0	5.2	12.1	25	40
Biogas	42.1	49.1	49.1	49.1	56.1	84.1
Total	1,824	1,890	1,974	2,028	2,092	2,867

Source: Action Plan for Amending the Action Plan for RES from 2017

Latest Legislation, Incentives and National RES Policy

The current policy regarding support for RES investments is based on Feed-in Tariffs (FIT) and Feed-in Premiums (FIP). The latter is prescribed in the Energy Law of 2018, and is therefore a newly implemented support scheme in North Macedonia.

The support schemes are explicitly defined in the Decree on the Measures for Support of Electricity Generation from Renewable Energy Sources[39]. It defines FIT as a guaranteed price for the energy produced by an eligible energy source under a contract, while FIP represent a fixed premium to the price per kWh at which the producer has sold its energy on the wholesale market. In case the producer is unable to sell on the market, the energy produced shall be bought by either a trader or supplier previously nominated by the MoE. The eligible technologies for FIT are:
• Hydro power plants no larger than 10 MW
• Wind power plants no larger than 50 MW
• Biomass power plant no larger than 1 MW
• Biogas power plant no larger than 1 MW
Whereas, FIP eligible technologies are:
• Wind power plant no larger than 50 MW
• Solar PV power plant no larger than 30 MW

In addition to FIT and FIP, RES producers enjoy other benefits and preferential treatment. For instance, producers contracted under the FIT scheme are guaranteed to sell all energy they produce and are therefore not balancing responsible parties. This responsibility is taken on by the MO. Producers under the FIP scheme do not benefit from this treatment. Then, the TSO and DSOs are obliged to grant priority access and dispatch to RES producers and highly efficient combined heat and power plants in an objective, transparent and non-discriminatory manner and under the conditions set out in the network codes. Priority access and dispatch may only be suspended in cases of risks to system security of supply, and the corresponding operator must notify the ERC of the reasons.

[39] Government of North Macedonia, Decree on the Measures for Support of Electricity Generation from Renewable Energy Sources, February 2019

Table 5.158 below summarizes the duration and level of support available to RES plants under these two support schemes.

Table 5.158 **Information on the level of support and duration by type of RES**

RES type	Level of support (€¢/kWh)[40]	Duration of support (years)
Feed-in Tariffs		
Hydro (kWh/month)		
≤ 85000	12.00	
> 85000 and ≤ 170000	8.00	20
> 170000 and ≤ 350000	6.00	
> 350000 and ≤ 700000	5.00	
> 700000	4.50	
Wind	8.90	20
Biomass	15.00	15
Biogas	18.00	15
Feed-in Premiums		
Wind	Auction	20
Solar PV	Auction	15

Source: Government of North Macedonia, Decree on the Measures for Support of Electricity Generation from Renewable Energy Sources, February 2019

In February 2019, the Government also brought a Decision on the Total Installed Capacity of Preferential Electricity Producers[41]. It defines the limits on capacity that can be contracted under the FIT or FIP scheme, and by extension it sets out the budget for the FIT scheme.

In particular the capacity limits for FIT are:
• 86 MW for wind power plants
• 10 MW for biomass power plants
• 20 MW for biogas power plants
- 7 MW until 31 December 2019
- 13 MW after 1 January 2020

Under the FIP scheme, Solar PV installed capacity is limited to 200 MW. In addition, the Programme for Financial Support of Preferential Producers under Feed-in-Premium Scheme[42] defines the budget for the FIP scheme to be 30 million MKD, roughly equivalent to around 490,000 Euro.

Lastly, the maximum reference value of the fixed premium for PV in 2019 was 15€/MWh. Wind power capacity was not covered by the Decision or Programme because the government did not have plans to open a tendering procedure for this type of RES during 2019.

Installed Capacity per Source

The data on installed RES capacities and generation in 2018 per type of RES is released by the ERC in their annual report, and it is summarised in Table 5.159.

Table 5.159 **Types of Renewable Energy Sources**

	RES type	Installed capacity (MW)	Electricity generation (TWh)
1	Wind onshore	36.8	0.097
2	Wind offshore	0	0
3	Solar PV	18.49	0.023
4	Solar thermal	0	0
5	Hydro		
5.a	Small hydro	106.32	0.214
5.b	Large hydro with reservoir or run-of-river	586.65	1.625
6	Biomass		
6.a	Bio-solids	0	0
6.b	Biogas	7	0.054
6.c	Waste	0	0
7	Geothermal	0	0

Source: Government of North Macedonia, Decree on the Measures for Support of Electricity Generation from Renewable Energy Sources, February 2019

Planned New Major Projects

With the new support mechanisms, the number of RES investment projects in North Macedonia is expected to increase in the following years. Nevertheless, there are a few confirmed and currently ongoing RES investment projects:

(1) The wind park Bogdanci was originally planned to have a capacity of 50 MW. With 38.2 MW already built and commissioned in 2014, ESM has been working on completing the project in the previous years. The projected

40 Excluding VAT
41 Government of North Macedonia, Decision on the Total Installed Capacity of Preferential Electricity Producers, February 2019, Official Gazette of the Republic of North Macedonia, No. 29/19
42 Government of North Macedonia, Programme for Financial Support of Preferential Producers under Feed-in-Premium Scheme for 2019, February 2019, Official Gazette of the Republic of North Macedonia, No. 29/19.

construction period is 2.5 years and the planned commissioning date is in early 2022. The new 13.2 MW are expected to yield a yearly generation of 0.037 TWh.

(2) ESM have announced two large solar PV long-term projects to be built in multiple stages

I. Solar power plant Oslomej which is planned to have 100 MW capacity at its final stage. So far, there are actions taken for the first two stages.

- The first stage is 10 MW which should be completed within 8 months of commencing, setting the expected commissioning date in late 2020. The planned yearly generation is 0.015 TWh.
- The second stage of 20 MW is currently subject to a feasibility study. Its projected construction time is 1.5 years, with an expected commissioning date in 2021. The planned yearly generation is 0.030 TWh.

II. 120 MW solar power plant Bitola, near the largest thermal power plant in the country.

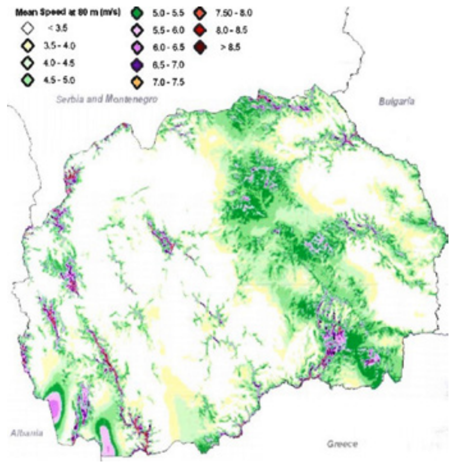
- A feasibility study is being conducted for the first stage of 20 MW. The projected construction period is 1.5 years, with expected commissioning date in 2022. The planned yearly generation is 0.030 TWh.

(3) The FIP scheme was implemented for the first time through a tender procedure in summer 2019. As outlined above, this scheme is expected to cover 200 MW of Solar PV plants, while there is no decision on the coverage of wind plants to this date. With this, North Macedonia has become the third contracting party to the EnC to launch a competitive process for supporting the investment in RES. The first tender awarded support in the form of fixed premium for a total of 35 MW of solar PV, which are to be built on state-owned land in two locations locations:

- 25 MW in Sveti Nikole split into 10 MW, 5 MW, two plants of 2 MW and six plants of 1 MW;
- 10 MW in Makedonski Brod.

Once the Government approves support for new wind power capacity, new investment projects are expected to emerge. The wind potential in North Macedonia is shown in Map 5.53.

Map 5.53 **North Macedonia wind speed map at 80 m**



Source: ERC, Annual Report 2018

Energy Efficiency and Cogeneration

National Targets

A new Energy Efficiency Law[34] was introduced in February 2020. The Law partially transposes the newest EU Energy Efficiency Directives. These Directives will be fully transposed by the adoption of the deriving secondary legislation. The Law stipulates the following basic obligations for the Governmental institutions:

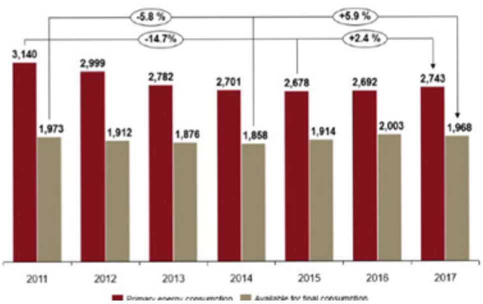
- To prepare and adopt a long-term Strategy to 2030 for Reconstruction of Housing, Public and Commercial Buildings, which is envisaged to provide an efficient, economically justifiable reduction of energy consumption by applying energy efficiency measures and at the same time reducing environmental pollution;
- To adopt a Decree on national energy efficiency goals and, accordingly, to develop three-year Action Plan for the implementation of EE measures;
- In order to ensure effective monitoring and verification of the implementation of EE measures, the Energy Agency shall manage, maintain and upgrade a web-based monitoring tool - Monitoring and Verification Platform (MVP);
- To adopt a Rulebook on MVP tool that will prescribe the procedures and technical parameters for the tool, as well as the rules for use and updating;

[34] Energy Efficiency Law, Official Gazette of the Republic of North Macedonia, No. 32/20, [Online]. Available only in local language: http://www.economy.gov.mk/doc/2766

- To regularly prepare and adopt three-year National Energy Efficiency Plan (NEEAP) and report on its execution to the relevant national and international institutions and bodies.

The last NEEAP covered the period until 2015 and its achievements were duly reported to the EnC Secretariat[44]. In general, primary energy consumption saw a decreasing trend, while final energy consumption remained stable. Between 2011 and 2017, the primary energy consumption decreased by 12.6% mainly due to a higher import of electricity and petroleum products, but partly due to implementation of energy efficiency measures and increased RES electricity production. This is shown in Figure 5.210.

Figure 5.210 **Primary energy and final energy consumption, 2011 – 2017 [ktoe]**



Source: Energy Development Strategy until 2040

In the last (3rd) NEEAP, it was estimated that achieved energy savings in 2015 amounted to 79.4 ktoe, or 4.85% of the reference consumption. That means that 99% of the planed energy savings in 2015 were achieved, as shown in Figure 5.210.

The Plan reinforced measures from its predecessor and introduced two new measures that together would contribute to cumulative energy savings of 148.7 ktoe in 2018.

This value represents a 9.09% reduction compared to the reference consumption. In addition, projections of primary energy consumption for 2020 were made taking 2016 as a base year and assuming and annual growth rate of 2.2%. As a result, the NEEAP estimated that primary energy consumption in North Macedonia will reach 3,014 ktoe in 2020, upholding the primary energy 'individual cap consumption' set for EnC countries, which is 3,270 ktoe. The 4th NEEAP for the period 2020-2023 is currently under preparation. It should set a new target against 2015 as a base year. It is expected that, after a public consultation, a draft plan will be submitted to the Government for adoption in April 2020 at the latest.

Furthermore, regarding the short deadlines on adoption of bylaws set by the then draft EE Law, a donor meeting was held with the aim to coordinate technical assistance in their preparation as early as November 2019. A consultancy of EBRD, under the 'Policy Window' of the Regional Energy Efficiency Program (REEP Plus), for the preparation of the Regulation setting out the binding energy efficiency scheme and the manner and measures for achieving the target referred to in Article 7 of the Energy Efficiency Directive has been agreed. The Government can choose measures to achieve savings of 0.7% per annum in final energy consumption compared to 2015.

Incentive-based Initiatives in the Building Sector

The currently conducted energy efficiency programme in the building sector is the National Programme for Energy Efficiency in Public Buildings in North Macedonia until 2020[45]. The 3rd NEEAP outlines 31 policies and measures, the majority of which have been implemented. The measures are divided in seven sectors: buildings, household, public, commercial, industry, energy and transport. Where the measures overlap multiple sectors, their overall savings are reported separately.

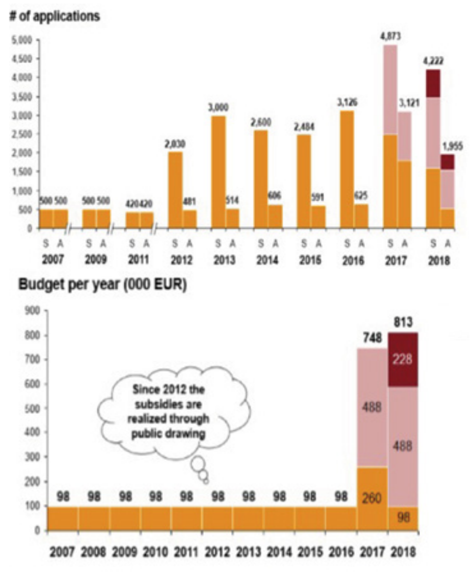
The implementation of measures on solar collectors, municipal street lighting, wider application of RES, and greater use of railway, all exceeded expectations. One third of the

44 https://www.energy-community.org/implementation/North_Macedonia/reporting.html
45 Draft National program for energy efficiency in public buildings in North Macedonia until 2020 (Phase I) is developed under the GEF Sustainable Energy Project and with technical assistance of, the World Bank Institute.

measures are partially implemented and only one (heat cost allocators) was not implemented at all.

The usage of RES and EE in households is promoted under the annual National Programme, implemented by the MoE. The following support schemes are stipulated in the programme: up to 30% reimbursement, with a cap of 300 €, of the costs for purchasing and installation of solar thermal collector system; up to 50% reimbursement, with a cap of 500 €, of the costs for purchasing and installation of PVC or aluminium windows; and up to 50% reimbursement, with a cap of 500 €, of the costs for purchasing a pellet stove. The eligible technologies are revised each year. The programme's popularity has been rising in previous years, as shown in Figure 5.211.

Figure 5.211 **Number of applicant and budget for promotion of RES and EE in households, 2007 - 2018**



Source: Energy Development Strategy until 2040

Furthermore, the Government adopted the Program for Promotion of Renewable Energy Sources and Promotion of Energy Efficiency in Households for 2019[46]. In 2019, 763 households were subsidized, out of a total of 1306 applicants who purchased and built solar collectors (about 163,000 €). Furthermore, 1503 households, out of a total of 2471 applicants, were subsidized for purchased and installed PVC or aluminium windows (about 646,000 €) and out of a total of 1863 applicants who purchased pellet stoves in their homes, 932 households were subsidized with about 50,000 € from the Budget.

EU Funded (or otherwise funded) Energy Efficiency Programmes in the Building Sector

The 3rd Annual Report Under the Energy Efficiency Directive[47] issued in June 2019 reports the following internationally funded projects, which are currently ongoing:

- A World Bank Public Sector Energy Efficiency Project through which, according the key findings and agreements reached during the mission in May 2019, the project will include a 25 million € IBRD loan to reduce energy consumption in the public sector and support the establishment and operationalization of a sustainable financing mechanism for the public sector (the proposed Energy Efficiency Found);
- An EBRD project through which five municipalities will conclude public private partnerships (PPPs) for providing public lighting energy services;
- A technical assistance form GIZ for operationalization of the Monitoring and Verification Platform (MVP) has been provided. The MVP platform will enable good communication and coordination between the national and local levels;
- A Residential Energy Efficiency project in the Western Balkans (WB) as part of the Economic Resilience Initiative-Infrastructure Technical Assistance (ERI-ITA) project, funded by the European Investment Bank (EIB);
- A Cool Heating project financed by Horizon 2020 - Framework programme for research and innovation 2014-2020. The project promotes an implementation of "small

46 Program for Promotion of Renewable Energy Sources and Promotion of Energy Efficiency in Households for 2019, Official Gazette No.15 / 2019
47 https://www.energy-community.org/implementation/North_Macedonia/reporting.html

modular renewable heating and cooling grids" for communities in SEE.

Cogeneration: Regulatory Framework, Installed Capacity

The currently operational cogeneration plants (CHPPs) in North Macedonia are CHPP TETO (227 MWe)[48], CHPP ESM Energetika (25 MWe) and CHPP Kogel Sever (30 MWe)[49].

The production of electricity by these three CHPPs is included within the information on electricity sector and specifically can be observed in Table 5.160. According to the new EE Law, the 5-year Programme for implementation of the Energy Development Strategy until 2040 (to be in place by mid-2020) should include the potential for application of highly efficient cogeneration and efficient district heating and cooling as well as cost-benefit analyses.

District Heating applications

The ERC Annual Report 2019[50] states that active district heating systems in the Republic of North Macedonia are present only at the territory of the City of Skopje, where there are three functioning systems. The largest district heating system is the one managed by BALKAN ENERGY GROUP JSC Skopje (BEG)[51], which in 2019 had about 53,281 consumers connected, with overall of engaged capacity of 475 MW, while 3,740 consumers were connected to the system of ESM JSC Skopje, Energetika Subsidiary with a total engaged power of 50 MW, and 496 consumers were connected to Skopje Sever JSC Skopje with an engaged power of 8 MW.

According to the Energy Law, for the systems with installed power of consumers of over 80 MW, licenses holders for production, distribution and supply of heat cannot be a single legal entity.

Therefore, BEG comprises three subsidiaries: BEG Heat Production, BEG Distribution of Heat and BEG Supply of Heat. In the systems operated by ESM JSC, Energetika Subsidiary and Skopje Sever, engaged power of the consumers is under 80 MW, and therefore all three licenses for production, distribution and supply are given to the single companies. They are all regulated businesses.

The BEG Heat Production capacities, connected to the grid of BEG Distribution of Heat, are:

- Thermal power plant Istok with installed thermal power of 279 MW, located in the east industrial zone of the city,
- Thermal power plant Zapad, with installed thermal power of 171 MW, located in the Taftalidge settlement and
- Thermal power plant 11-ti Oktomvri with installed thermal power of 28 MW, located in the Kisela Voda settlement.

The total installed thermal power of the heat plants (HPs) managed by BEG Heat Production is 478 MW, whereby natural gas is used to produce thermal energy. The CHPP TETO JSC Skopje is also connected to the distribution grid of BEG Distribution of Heat. It is with installed thermal power of 160 MW and is an only unregulated heat producer. ESM JSC Skopje, Energetika Subsidiary[52] owns the CHPP ESM Energetika and the CHPP Kogel Sever.

The total installed thermal power of ESM JSC Skopje, Energetika Subsidiary amounts 96 MW. ESM JSC Skopje also owns the majority part of the distribution grid managed and used by ESM JSC Skopje, Energetika Subsidiary.

Skopje Sever JSC Skopje produces thermal energy through two boilers of 23 MW each, i.e. has total installed thermal power of 46 MW. Heat production capacities of different producers, in 2019[53], are summarized in Table 5.160.

48 CHPP ESM Energetika untypically exists of two turbogenerators with installed electrical power of 12.5 MW each, built on the top of three existing thermal turbines with installed power of 32 MW each. The thermal units are mainly used for production of thermal energy. Source of information: ESM JSC Skopje
49 ERC, Annual Report 2018
50 https://www.erc.org.mk/pages_en.aspx?id=98
51 http://balkan-energy.com/en_US/
52 https://www.esm.com.mk/?page_id=3582&lang=en
53 ERC, Annual Report 2019, https://www.erc.org.mk/pages_en.aspx?id=98

Table 5.160 **Installed heat production capacities, in 2019**

Company	Heat Plant / Boiler	Fuel	Tech-nology	Capacity [MW]
BEG Production	TO Istok	Natural gas	HP	279.12
BEG Production	TO Zapad	Natural gas	HP	170.97
BEG Production	TO 11 Oktomvri TO	Natural gas	HP	28.21
TE-TO Skopje	TE-TO Skopje	Natural gas	CHPP	160
ESM	ESM Energetika K1	Natural gas	HP	32
ESM	ESM Energetika K2	Natural gas	HP	32
ESM	ESM Energetika K3	Natural gas	HP	32
ESM	TE-TO KOGEL TE	Natural gas	CHPP	13.58
SKOPJE SEVER	Skopje Sever K1	Natural gas	HP	23
SKOPJE SEVER	Skopje Sever K2	Natural gas	HP	23

Source: ERC, Annual Report 2019

The overall heat production capacity is 793.88 MW, whereby, the engaged capacity of users is approximately of 510 MW. This situation provides connection opportunities for new heat consumers in the City of Skopje.

The heat production is dependable on the meteorology conditions, and usually the largest production is reached in the months of December and January. The overall heat production (kWh) in 2019[54] is presented in Table 5.161, below.

In line with the information of BEG Heat Distribution, the total length of its distribution network, including the length of connection points to facilities, as by the end of December 31, 2019, is 227 km. The length of BEG's distribution network and of the networks of the other two distributers, are given in Table 5.162. This Table also contains an information on average losses by distribution network.

Table 5.162 **Length of Distribution Networks and related Average Losses, in 2019**

Distributer	Length of Distribution Network (km)	Average Losses (%)
BEG Distribution	227	11.37
ESM Energetika	38	12.00
Skopje Sever	10	17.30
Total	275	

Source: ERC, Annual Report 2019

BEG Heat Supply is with the largest share of 88 % in the overall of the delivered quantities of heat. Next, is the system of AD ESM, Subsidiary Energetika with the share of 10 %, and the last is Skopje Sever with the share of 2 % in the overall delivered quantities of heat. Most of the consumers, about 77%, belong to the category of households.

The delivered quantities of heat in the past 10 years, by the three operational suppliers, are presented in the Figure 5.212.

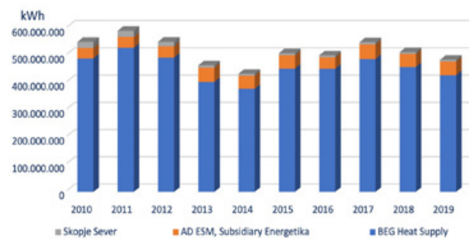
Table 5.161 **Production of heat (kWh), by months and producers, in 2019**

January	67,455,499	69,823,099	10,887,000	2,244,000	150,409,598
February	55,112,299	36,707,400	9,844,000	1,485,000	103,148,699
March	52,641,598	0	5,103,000	831,000	58,575,598
April	27,609,400	0	2,623,000	448,000	30,680,400
October	6,612,200	6,118,099	1,514,000	268,000	14,512,299
November	36,600,700	17,882,000	4,938,000	976,000	60,396,700
December	56,208,899	50,658,900	12,015,000	1,802,000	120,684,799
Total	302,240,595	181,189,498	46,924,000	8,054,000	538,408,093

Source: ERC, Annual Report 2019

54 ERC, Annual Report 2019, https://www.erc.org.mk/pages_en.aspx?id=98

Figure 5.212 **Delivered heat by supplier (kWh), in the past 10 years**



Source: ERC, Annual Report 2019

Development and Investment Plans

In the forthcoming five-year period, BEG Heat Production plans to invest about 3 million €, in modernization and increased efficiency of its production facilities. It is expected that this investment will prolong the life cycle of their heat plants for the next 20 years[55].

Planned New Major Projects

The 3rd Annual Report Under the Energy Efficiency Directive[56] identifies the preparation of the following new EE projects in the Building Sector:

- An IPA2 Grant scheme for implementation of pilot measures for climate change and energy efficiency with emphasis on public buildings is under preparation, through which 4 million € will be provided from EU IPA funds;
- Negotiations are under way for launching a 25 million € through Loan Agreement for the Public Sector Energy Efficiency Project, which is part of the new four-year Strategy of EBRD – World Bank for partnership with our country for the period 2019-2023;
- EE Renovation of State Student Dormitories Project until 2024. The total investment value of the project amounts to approximately 25 million € (a loan from Germany, via KfW, in the amount of 20 million € and a grant from EU in the amount of 4.785 million €).

Furthermore, application of measures such as Energy Efficiency Binding Scheme, which prescribes rules and obligations for the distribution network operators and/or suppliers to achieve savings in the end-use energy consumption or to prove it by application of alternative measures, are prescribed by the new Law. Alternative measures include introduction of new pollution taxes, sale of energy-efficient products (other than those already in place), establishment of an EE Fund, voluntary agreements introducing high-efficiency technologies, campaigns, introduction of fees for purchasing inefficient products, i.e. use of inefficient services, renovation of municipal buildings and public enterprises, etc. The Law introduces an obligation for reconstruction of at least 1% of the total area of buildings used and/or owned by Government, annually.

Lastly, the EnC Secretariat places a focus on EE in buildings with its programme 2021 -2027[57]. Taking into account that the topic is expected to be prominent in the next EU financial framework 2021-2027, the EnC Coordination Group prepared this programme to tackle forthcoming EE issues. In order to do so, the programme sets out to assess and improve the national institutional, legal and regulatory frameworks governing the housing sector with an impact on energy investment. Its priorities include working with municipalities on heating and cooling, as well as nearly zero energy buildings, stricter EE requirements for appliances, and innovative funding programmes for residential buildings renovation

55 ERC, Annual Report 2019, https://www.erc.org.mk/pages_en.aspx?id=98
56 https://www.energy-community.org/implementation/North_Macedonia/reporting.html
57 https://energy-community.org/news/Energy-Community-News/2020/03/12.html

Energy Investment Outlook

The Energy Development Strategy sets out the following estimates and principles regarding investments between 2020 and 2040:

- A cost competitive transition would require a cumulative overnight capital investment ranging 9.4 – 17.5 billion € in the energy system of North Macedonia, depending on selected strategic scenario (Green, Moderate or Reference scenario).
- EE and RES investments are the primary focus of all scenarios. This allows the opportunity to benefit from increasing access to funding programmes that recognize the importance of energy transition projects - primarily EU funds as well as international financial institutions and donors.
- EE and RES projects, as well as the revitalization of TPP Bitola, will be also supported through the national budget.
- The pivotal year in the development is 2025, and decisions made in 2020 or 2021 at the latest will greatly influence the path through the energy transition. This requires immediate actions from the relevant energy stakeholders to start activities at all governance levels.

Since the Energy Development Strategy was adopted just recently (February 2020), an Action Plan for implementation of the Strategy, which will specify projects in different sectors, is to be prepared during 2020. Therefore, only information on short to mid-term investment plans of the regulated companies in the electricity and natural gas sectors of North Macedonia are available, either from the ERC's Annual Report 2018 or from sources within the companies themselves. That data is presented in the following sections. Collected information from different unstructured sources on potential mid-term investments in EE are presented along with the project descriptions in sections 4.6(c) and 4.6(e) of this text.

Electricity and Renewables

According to MEPSO's Ten-Year Network Development Plan until 2029[58], the major investments are presented in Table 5.163 and Table 5.164.

Table 5.163 **MEPSO Development Plan for the period 2019-2029**

No.	Projects	Budget Contract (MEUR)	Development plan (2019)	Development plan (2018)	Explanation about the costs difference or the time for commencement
Интерконективни врски					
1	400 kV interconnection line SS Bitola 2 – Macedonian/Albanian border	29.40	27.01	29.31	Costs structure is updated following the completed project and tender documentation and the procurement plans.
New transmission lines and transformer substations					
2	Transformer substation 400/110 kV SS Ohrid and new 400 kV OHL bay SS Bitola 2	14.00	13.72	17.61	Costs structure is updated following the completed project and tender documentation and the procurement plans.
3	Connection of 110 kV OHL HPP Vrutok - SS Skopje 1 in a transformer substation in the region of Polog	5.10	5.10	5.10	The completion time is prolonged for a year due to the specifics of the terrain, and the difficulties during tracing the access corridor.
4	Costruction of SS 400/110 kV Kumanovo (1 x 300 MVA)	15.00	15.00	8.60	The investment cost is updated in accordance with the actual prices of equipment, design and built of this type of facility.
Revitalization/ reconstruction of 110 kV lines					
5	Revitalizations of 110 kV lines	3.00	3.00	3.00	
6	Revitalization of OHL 2x110kV section Vapila - SS Ohrid 1	0.58	0.58	0.58	
7	Reconstruction of 110 kV OHLs section Vrutok - Tetovo	0.54	0.54	0.54	
8	Reconstruction of 110 kV OHL SS Shtip - TC Probishtip	2.45	0.42	1.92	The realization of the project has begun in 2018, the cost is updated according to the signed Contract, and in the development plan (2019) are given the funds for 2020.
9	Reconstruction of 110 kV OHL SS Bunardzik - SS Miladinovci	1.20	1.20	3.20	A new route is suggested as per rational execution; the newconnection point of the 110 kV OHL towards Miladinovci will be SS Bunardzik.
10	Reconstruction of 110 kV OHL SS Veles - SS Ovche Pole	1.81	1.16	3.19	In the development plan (2018) are used investment costs, while the contracts were signed at the end of 2019. The execution has stared in 2019. The costs and rate of progress were updated as per thesigned contracts and construction plans in coordination with the Bank. In the development plan (2019) the price was updated as per the contracts and the dynamic of costs given from 2020 onwards.
11	Reconstruction of 110 kV OHL SS Ovhe Pole - SS Shtip	1.41	1.01	2.88	
12	Reconstruction of 110 kV OHL SS Bitola 1 – SS Prilep	3.92	3.23	4.23	
13	Reconstruction of 110 kV OHL SS Skopje 4 –SS Petrovec - SS Veles	2.99	2.31	4.03	
14	Reconstruction of OHL 110 kV Gostivar (Bukovikj) - TPP Oslomej - Kichevo - Sopotnica - Bitola 1 length = 100 km AAAC)	3.10	3.10	3.10	The completion time is postponed for a year due to the optimization procedure during designing.
15	Reinforcement of the grid in the southeast region variant 1:Double-circuit 110 kV OHL to Strumica length = 57,5 km, AAAC-Z) or variant 2: 400/110 kV SS in Strumica (300 MVA)	7.1-25.0	7.10	5.24	The commencement of the project is planned 3 years earlier due to the increased interest for construction of RES in th SEE region. Unvestment costs were given about two variants, the costs wil be determined depending on the results from the Study (No.43).

58 https://www.mepso.com.mk/en-us/Details.aspx?categoryID=123

Table 5.163

No.	Projects	Budget Contract (MEUR)	Development plan (2019)	Development plan (2018)	Explanation about the costs difference or the time for commencement
16	Reconstruction of OHL 110 kV Polog - HPP Vrutok - HPP Shpilje - HPP Globochica - Struga length = 100 km, AAAC)	7.95	1.00	9.06	The investment cost is updated following the actual prices of equipment, design and built of this type of facility, and in the plan ae given the funds for 2027-2029.
Revitalization /Reconstruction of transformer substations					
17	Revitalization of transformer substations	14.20	14.20	14.20	
Reconstruction/upgrade of swichyard Kratovo					
18	Construction of 110 kV transmission bays, complete Reconstruction and digitalization of the switchyard	0.70	0.70		New project for upgrade of switchyard Kratovo.
Ревитализација на ТС Скопје 4					
19	High-voltage equipment (breakers, disconnectors, *measurement transformers)*, control panels	4.80	2.34	4.36	
20	Power transformer (5-СК4-1ТА)	2.50	2.50	2.50	
Revitalization of SS Dubrovo					
21	High-voltage equipment (breakers,disconnectors, measurement transformers), auxiliary equipment (relay protection, SCADA, measurement transformers), rectifiers of 220 DC systems)	4.62	0.24	1.41	
22	Power transformer (3-ДУБ-1ТА)	2.50	2.50	2.50	
Revitalization of SS Bitola 2					
23	High-voltage equipment (*110 kV breakers)*, secondary equipment	1.00	0.42	0.93	
24	Power transformer	2.40	2.40	2.40	
Revitalization of SS Valandovo					The costs and the rate of progress are updated according to the signed contracts and current plans for execution; the dynamic of costs are given from 2020 onwards.
25	BH equipment (measurement transformers, breakers and disconnector)	0.77	0.18	0.70	
Revitalization of SS in TPP Oslomej					
26	BH equipment (diconnectors breakers measurement transformers)	0.63	0.21	0.57	
Revitalization of SS in HPP Tikvesh, HPP Vrutok, HPP Globochica and HPP Shpilje					
27	Secondary equipment (relay protection)	0.63	0.19	0.56	
Revitalization of SS Prilep 1					
28	High-voltage equipment (breakers,disconnectors, measurement transformers), auxiliary equipment (relay protection, SCADA, measurement transformers), исправувачи на 220 DC систем)	1.12	0.26	1.01	
Revitalization of SS Veles and SS Kavadarci 1					
29	Adaptation. Supply and installation of the primary equipment, installation of SACS, Protection and DC supply	0.54	0.54	0.52	
Revitalization of SS Kochani					
30	Shunt compenzation in 110 kV SS Kochani (25 Mvar)	0.75	0.75	0.75	
Modernization of the transmission system					
31	Telecommunication equipment and remote monitoring of the transformer substations	5.00	5.00	4.79	The cost and dynamic are updated following the plans for supply and installation.
32	Underground facility for optical connection	0.20	0.20	0.20	The commencement period is postponed for a year due to terrain problems.
33	Balkan Digital Highway	5.80	5.80		*Студија за развој на оптичка и телекомуникациска мрежа и проценка на вкупни трошоци за интегрирање во национален широко појасен план* и *Проектот за ревитализација на телекомуникациска мрежа* се надградени во регионален проект за креирање „дигитален автопат", финансиран преку WBIF и координиран од Светска Банка.
34	Wide Area Monitoring System-WAMS	0.15	0.15	0.15	Цената и динамиката е ажурирана според плановите за набавка и инсталација.
35	DLR - Dynamic Line Rating	1.23	1.23	0.60	New smart grid project as part of the Implementation of new technologies in the transmission grid; the project is needed for optimal utilization of the existing capacity of the transmission lines
36	Special software and hardware package for maintenance of the transmission grid	0.27	0.27	0.20	The cost and dynamic are updated following the plans for supply and installation.
Research on Power Transmission System					
37	CROSSBOW	0.18	0.10	0.15	The costs are updated in in accordance to the planned undertakings in 2020 and 2021.
38	TRINITY	0.80	0.08	0.08	New scientific and research project financed by Horizon2020.
39	Study on Optimal Utilization of the Double-circuit Busbars in the Substations	0.02	0.02	0.02	The commencement period is shortened as to faster concept implementaton.
40	Transmission Network Development Study	0.08	0.08		Preparation of a new Transmission Grid Development Study based on the new Energy Development Strategy.
41	Action Plan for Power Grid Strengthening to Support Renewable Eenergy Projects in North Macedonia	0.08	0.08		New study financed by EBRD because of the actuality of the RES integration.
42	Study on Voltage Profile Improvement of the Smart Grid	0.60	0.60	0.60	The Study is expected to be completed at the beginning of 2020.
43	Strengthening the Transmission Network in the Southeast Region of North Macedonia	0.25	0.25	0.03	The Study will be carried out as part of the WBIF Grant for technical support and and will have enlarged scope of work: more variants, project and tender documentation for optimal variant.
Cancelled/posteponed projects and undertakings in the new development plan					
	Reconstruction/revitalization of 110 kV OHL SS Kavadarci -HPP Tikvesh				By the Strategy for reconstruction/revitalization of the transmission grid, these reconstructions have a lower priority for realization and are excluded from the 10-year period.
	Reconstruction/revitalization of 110 kV OHL SS Gj. Petrov –SS Skopje1				
	Study for tower testing station				The project is delayed.
	Study for Procedures and Technologies for Organization, Operation and Planning in MEPSO				The study is delayed.
	Investigation of Potential Increase of the Bidirectional Transfer Capacity in the MK-GR Border				The results of the new calculations for system requirements by ENTSO-E TYNDP2020 are expected.

Projects financed by loans, investment grants and Smart Grid grant (EBRD 46iO's own funds
Projects financed by loans EBRD 44114 and AD MEPSO's own funds
Grant WBIF
Grant EBRD
Grant HORIZON 2020

Source: ERC, Annual Report 2019

Table 5.164 **Overview of cost for connection to transmission grid**

No.	Connections	Defined and approved documents connection costs to the transmission grid	Connection costs: Fixed costs: Costs for:	amount (MKD without VAT)	Variable costs*: Costs for:	amount (MKD without VAT)
1	VPP Bogoslovec	Study on connection to the transmission grid prepared: 25.04.2017 Annex to the Study on connection to the transmission grid prepared: 05.06.2018 Approval for connection to the transmission grid issued: [illegible]	1. Study on connection to the transmission grid	1,650,090.00	transmission grid comprised of: 1. Connected 2x110kV line 2. 110kV switchyard and MEPSO's Control and Command Building in SS Bogoslovec 3. Equipping of the 110kV	2,278,000.00
			2. Approval of technical documentation	55,003.00		
			3. Construction supervision	16.500,90 x T**		
			4. Compliance testing	in accordance with the real costs		
2	VPP Demir Kapija	Study on connection to the transmission grid prepared: 19.06.2018 Approval for connection to the transmission grid issued: 19.07.2018	1. Study on connection to the transmission grid	1,644,780.00	Connection to the transmission grid comprised of: 1. 110 kV transmission bay in SS Dubrovo	325,000.00
			2. Approval of technical documentation	54,826.00		
			3. Construction supervision	16.447,80 x T**		
			4. Compliance testing	in accordance with the real costs		
3	VPP Miravci	Study on connection to the transmission grid prepared:: 05.2019	1. Study on connection to the transmission grid	1,644,780.00	Connection to the transmission grid comprised of: 110 kV transmission bay in SS Valandovo	325,000.00
			2. Approval of technical documentation	54,826.00		
			3. Construction supervision	16,447.80 x T**		
			4. Compliance testing	in accordance with the real costs		
4	VPP Krushevo and TPP Krushevo	Preliminary study on connection to the transmission grid prepared: 07.2019	1.Study on connection to the transmission grid	1,717,680.00	Connection to the transmission grid comprised of: 110 kV transmission bay in SS Sopotnica	325,000.00
			2. Approval of technical documentation	57,256.00		
			3. Construction supervision	17,168.80 x T**		
			4.Compliance testing	in accordance with the real costs		
5	Direct user Cranfield Foundry	Study on connection to the transmission grid prepared: 17.11.2015 Annex to the study on connection to the transmission grid prepared: 03.09.2018 Approval for connection to the transmission grid issued: 04.09.2018	1. Study on connection to the transmission grid	547,770.00	transmission grid comprised of: 1. Connected 2x110kV OHL 2. 110 kV Switchyard and MEPSO's Control and Command Building in SS Neokazi 3. Equipping of 110kV Transmission bay in SS	1,804,000.00
			2. Approval of technical documentation	54,777.00		
			3. Construction supervision	16.447,80 x T**		
			4. Compliance testing	in accordance with the real costs		
6	Direct user IGM Trade	Study on connection to the transmission grid prepared: 02.2018 Approval for connection to the transmission grid issued: 26.03.2019	1. Study on connection to the transmission grid	548,260.00	Connection to the transmission grid comprised of: 1. Connection 110 kV lines 2. 110 kV swithcyard and Control and Command Building in SS IGM Trade 3. Equipping of 110 kV transmission bays in SS [illegible]	892,000.00
			2.Approval of technical documentation	54,826.00		
			3. Construction supervision	16.447,80 x T**		
			4.Compliance testing	in accordance with the real costs		
7	second transformer in SS Ovche Pole	Study on connection to the transmission grid prepared: 08.2017 Approval for connection to the transmission grid issued: 03.10.2019	1. Study on connection to the transmission grida	286,280.00	Connection to the transmission grid comprised of:110 kV transmission bay in Ovche Pole	325,000.00
			2. Approval of technical documentation	57,256.00		
			3. Construction supervision	17,176.80 x T**		
			4. Compliance testing	in accordance with the real costs		

Source: MEPSO, Ten-Year Network Development Plan until 2029

According to the Investment Plan of Elektrodistribucija for the period 2019-2024, the distribution system operator daughter company of EVN JSC, planned investments in the electricity distribution system are presented in Table 5.165.

Table 5.165 **Investment plan of Elektrodistribucija for the period 2020-2024 in 000 €**

Description	2020	2021	2022	2023	2024	Total 2020 - 2024
LV and MV projects	2,755	2,415	2,415	3,265	3,265	14,115
HV lines	/	2,590	1,551	926	520	5,587
Substations 110 kV and 35 kV	7,351	5,115	6,105	5,047	4,150	27,768
Transformers (110 kV, 35 kV, 10/20 kV)	/	1,872	1,372	1,872	1,272	6,386
ITC projects	2,919	1,064	1,153	934	719	6,789
Metering devices	8,075	7,902	7,726	7,441	8,076	39,220
Work safety & Environmental protection	377	253	404	302	373	1,710
IT (hardware & software)	/	1,574	1,272	731	692	4,269
Buildings	3,162	300	315	715	1,300	5,792
Vehicles	/	290	454	578	155	1,477
Unplanned projects	800	1,000	1,000	1,500	1,500	5,800
Connection of new users	8,000	8,000	8,000	8,000	8,500	40,500
Dislocation of meters	2,884	3,550	3,550	3,550	3,550	17,084
Investments by client's request	831	800	800	800	800	4,031
Total	**37,155**	**36,725**	**36,117**	**35,661**	**34,871**	**180,529**

Source: Elektrodistribucija, Investment Plan for the period 2019-2024

The latest Investment Plan of ESM considers the period 2020 – 2022 and its main aspects are presented in Table 5.166.

Table 5.166 **Investment projects and funds of ESM in the period 2020 - 2022**

No.	Project description	2020	2021	2022	Total 2020 - 2022
1	Solar PV PP 10 MW Oslomej 1	7,057	0	0	7,057
2	Solar PV PP 10 MW Oslomej 2	1,900	7,600	0	9,500
3	Solar PV PP 2x40 MW (up to 2x50 MW) Oslomej 3	100	2,400	0	2,500
4	Solar PV PP 20 MW Bitola 1	4,000	16,000	0	20,000
5	Wind park Bogdanci I and II phase	3,404	10,824	6,661	20,889
6	Wind park Miravci	165	430	14,433	15,028
7	Modernization and upgrade of DSO Energetika	634	33,545	53,610	87,789
8	Central heating system from TPP Bitola to 3 nearby villages, phase I	10,541	15,765	20,455	46,761
9	TPP Bitola mines	24,294	20,446	2,400	47,140
10	Design, revision and construction of lignite purification system	2,195	8,415	0	10,610
11	Revitalization and modernization of TPP Bitola, II phase	5,341	0	0	5,341
12	Revitalization and modernization of TPP Bitola, III phase (reduction of SOx and dust)	10,797	10,667	10,667	32,131
13	Other installations in TPP Bitola	1,081	2,504	2,504	6,089
14	Revitalization of HPP Globocica, III phase	200	15,951	10,434	26,585
15	Completing investments in HPP system Treska	386	2,142	0	2,528
16	HPP Cebren	396	6,755	1,921	9,072
17	SCADA in the ESM dispatch centre	400	1,600	0	2,000
18	Commercial software	640	0	0	640
19	Uncompleted investments from 2019	3,535	1,479	0	5,014
20	Studies, maintenance, equipment and tools	45,915	38,479	5,625	90,019
	Total	**122,981**	**195,002**	**128,710**	**446,693**

Source: ESM, Investment Plan for 2020 – 2022

Natural gas

Data on planed mid-term investments, which are presented in section 4,2(g), are gathered from the latest ERC's report and presented in Table 5.167 and Table 5.168.

Table 5.167 **Development and investment plan of natural gas TSO, GA-MA, in thousand €**

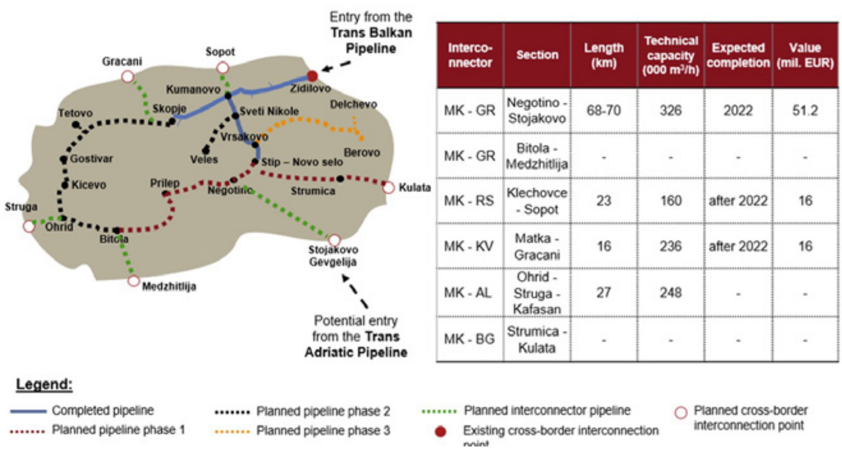
Investments	2019	2020	2021	2022	2023	Total
x1000 €	4,472	3,203	2,585	1,724	2,130	14,114

Table 5.168 **Development and investment plan of DTIDZ for TIDZ Skopje (thousand €)**

Investments	2019	2020	2021	2022	2023	Total
Equipment supply	33	65	65	65	65	293
Constructing pipe for connecting new users in "TIDZ Skopje1"	163	/	/	/	/	163
Constructing pipe for connecting new users in "TIDZ Skopje2"	407	/	/	/	/	407
Total	602	65	65	65	65	862

These correspond to an ambitious country-wide gasification plan. DTIDZ plans to provide the necessary investment funds from the Budget of the Republic of North Macedonia, as well as from the funds collected from the self-funding activities of the Directorate. Projects related to phase 1 are expected to be completed by 2020, phase 2 by 2022 and phase 3 after 2022.

Map 5.54 **Country-wide natural gas projects and planned interconnection points**



Interconnector	Section	Length (km)	Technical capacity (000 m³/h)	Expected completion	Value (mil. EUR)
MK - GR	Negotino - Stojakovo	68-70	326	2022	51.2
MK - GR	Bitola - Medzhitlija	-	-	-	-
MK - RS	Klechovce - Sopot	23	160	after 2022	16
MK - KV	Matka - Gracani	16	236	after 2022	16
MK - AL	Ohrid - Struga - Kafasan	27	248	-	-
MK - BG	Strumica - Kulata	-	-	-	-

Source: Energy Development Strategy until 2040

ROMANIA

Romania

Economic and Political Background

Romania's GDP was USD 250 billion in 2020, while the GDP per capita was 12,900 USD, according to the World Bank. For the first time ever, the World Bank classified Romania as a high-income country, based on 2019 data (per capita income of $12,630) - an important development for accession negotiations to the Organisation for Economic Cooperation and Development (OECD)[1].

The IMF's database of October 2020[2] showed that Romania's economy contracted 1.4% in annual terms in the final quarter of last year, above the preliminary estimate of a 1.5% decline and softening from the 5.6% drop tallied in the third quarter. All in all, the economy shrank 4.8% in 2020, swinging from 2019's 4.1% expansion and logging the worst reading in a decade. A second release showed that Romania's economy contracted 1.4% in annual terms in the final quarter of last year, above the preliminary estimate of a 1.5% decline and softening from the 5.6% drop tallied in the third quarter. All in all, the economy shrank 4.8% in 2020, swinging from 2019's 4.1% expansion and logging the worst reading in a decade.

Private consumption fell at a sharper rate of 5.5% year-on-year in Q4 2020, deteriorating from the 4.3% contraction in the previous quarter. Moreover, government spending dropped for the first time since Q2 2018, declining 1.2% (Q3: +3.5% y-o-y). However, fixed investment grew at a stronger rate of 6.5% in Q4 compared to the 2.7% increase recorded in the prior quarter. On the external front, exports of goods and services contracted at a slower pace of 3.1% year-on-year in the fourth quarter (Q3: -5.2% y-o-y). Meanwhile, imports of goods and services flatlined at the tail end of the year (Q3: -4.3% y-o-y).

On a seasonally-adjusted quarter-on-quarter basis, economic growth moderated to 4.8% in Q4 from 5.6% in the previous quarter. Looking ahead, the Romanian economy is expected to bounce back from 2020's pandemic-induced plunge on the back of reviving domestic and foreign demand. Moreover, incoming EU funds and an accommodative monetary policy should further support the recovery. However, much depends on the progress of vaccination efforts at home and in key trading partners, with new strains of Covid-19 and the possible prolongation of restrictions clouding the outlook. IMF estimates that Romania's GDP will expand by 4.6% in 2021, significantly higher than -4.8% in 2020.

The justice laws in Romania draw again tensions among politicians. The Chamber of Deputies finally voted for the abolishment of the Section for the Investigation of Crimes in Justice, a controversial prosecution office created for the investigation of corruption cases among magistrates. However, the bill adopted by the deputies also includes an amendment stipulating that magistrates can be prosecuted only with the approval of the magistrates' body, which raised the fear that a super-immunity of magistrates could be enhanced in this way. While the governing coalition agrees to the actual format of the law, the major opposition party supports the preservation of the institution. Recent tensions inside the coalition parties on new amendments to the justice laws point to further discussions on this topic.

A note on Unemployment

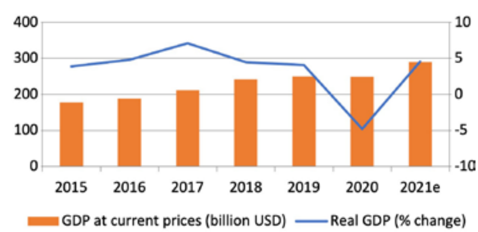
When it comes to **unemployment**, the official statistic for Romania has to be taken with a grain of salt. While low (5%) compared to the EU average (7%) – data for 2020[3], it does not reflect reality. Structurally, Romania has had, for a long time, a significant number of people active in the underground economy (an estimated 1/5 of the labor force).In addition, an estimated 3 million Romanians reside and work abroad, most of them in the EU.

[1] https://www.worldbank.org/en/country/romania/overview

[2] It should be noted that most of the available analyses (feeding the chapter "Energy and Emissions Projections for SE Europe") do not include the effect of the COVID-19 pandemic and its possible long-term effects to the macroeconomic development and the energy systems of the countries in the region.

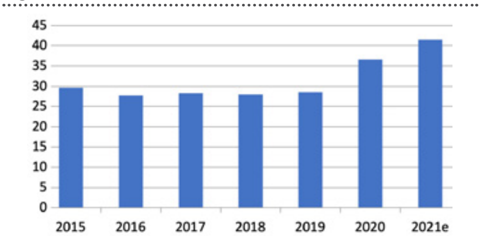
Of those who stayed in Romania, people who have been out of a job for many years have stopped looking altogether relying on informal, seasonal or household work (especially in rural areas) in order to get by, which is why a significant number of unemployed (at least 10%) are completely unaccounted for in the official statistics (since they are neither "employed" nor "unemployed" nor "looking for a job"). The **real unemployment figure should be at least 15%**. Romania has a population of 19 million, of which 7 million are economically inactive (children, pensioners, people with disabilities, housewives) which leaves a labor force of 12 million. According to the ILO, total labour force participation rate in Romania is just 55% (2018 data) which translates into 6.6 million employed people, implying that the remaining 45% (5.4 million) are unemployed. Of the 45% unemployed, only 5% (500,000 persons) are counted in the official unemployment rate. Another 20% (2.5 million) work in the underground economy, while the remaining 20% of the unaccounted unemployed is made up of structurally unemployed or the "extremely poor" (10%, 1.25 million) and seasonal workers that go abroad for short periods of time (10%, 1.25 million).

Figure 5.213 **Romania's GDP and its annual GDP growth**



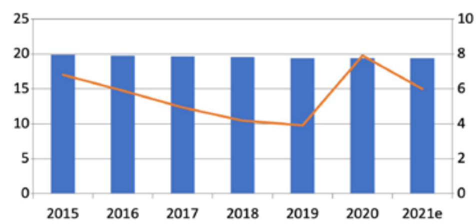
Source: IMF World Energy Outlook (October 2020

Figure 5.214 **Romania's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.215 **Romania's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy

The primary objective of Romania's energy policy is to ensure energy supply from its own internal sources. According to the final Integrated National Energy and Climate Plan (INECP) submitted by Romania in April 2020, energy policy is structured around 5 dimensions: decarbonization, energy efficiency, energy security, internal energy market, and research, innovation and competitiveness.

In some ways Romania's national energy strategy can be described as a white elephant. A document originally written in 2016, and subsequently re-written over 2017-2018 (but never adopted), it has little insight to offer, since much has changed in the past 2-3 years. Assumptions used 5 years ago are no longer valid. A more recent document, the INECP, also lacks focus and is mostly a wishlist – a collection of plans of state-owned companies combined with a regurgitation of EU legislation. Estimates made in Romania's INECP are already outdated, since they are based on assumptions made in 2016 by the PRIMES scenario. For instance, annual economic growth was projected to be 2.7% during 2020-2025 and 2% during 2025-2030 (INECP, pg. 141) – a projection that is already outdated.

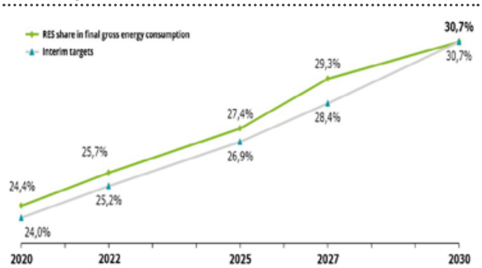
During 2017-2019, the country struggled to move towards decarbonization (decision makers fought to keep the coal-fired generation

[3] https://ec.europa.eu/eurostat/documents/portlet_file_entry/2995521/3-04032021-AP-EN.pdf/cb6e5dd6-56c2-2196-16b7-baf811b84a4f

until the very last moment, some still do). Only reluctantly Romania agreed to up the target for renewable energy sources for 2030 - initially set at 27.9%, it was increased to 30.7%, which is still below the 34% recommended by the European Commission. Under pressure from the European Union, Romania grudgingly agreed to mitigate.

In Romania, GHG mitigation during the next decade will mean:
- radical overhaul of the main coal-based electricity producer (Complexul Energetic Oltenia), which is to switch from coal to natural gas and renewables;
- extending the operating period of existing nuclear units + building new nuclear capacities;
- adding new RES capacities and promoting the use of hydrogen;
- developing/upgrading the existing infrastructure of electricity and natural gas networks;
- developing storage capacities.

Figure 5.216 **Projected RES share in final energy consumption (2021-2030), in %**



Source: INECP 2020

This target for RES will most likely be exceeded, due to the availability of extra funding for green projects, especially through the Resilience and Recovery Facility in the next few years and through the Modernization Fund (mechanism 10d), on top of the traditional EU funding channeled through the 7-year Multiannual Financing Framework (MFF). Hence, the key issue becomes Romania's ability to attract all this available money. Everything hinges on its ability to understand what energy transition is and what it is not. For instance, note analysts, energy transition does not mean granting a state loan of 250 €million to the main coal-fired electricity producer. On the other hand, it means having mature green projects, and avoiding wasting any more time and money with loss making enterprises by trying to keep them alive. There is a general consensus today in Romania that the Green Deal has not been sufficiently internalized and well understood, and the necessary strategic documents have not been updated to reflect the new imperatives.

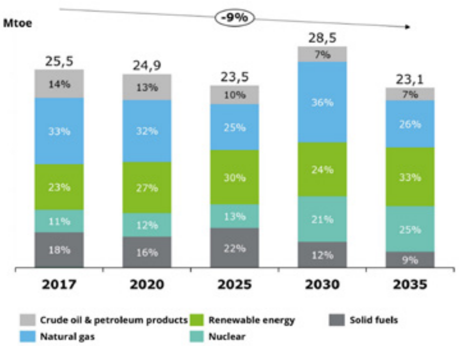
Governmental institutions
- **Parliament, the Committee for Industries and Services**, is responsible for drafting the primary legislation in the energy sector.
- **Energy Ministry** coordinates the state-owned companies in the energy field (with the exception of the TSO in electricity and natural gas).
- **General Government Secretariat/ Prime Minister's Office** has kept oversight of two key energy companies - the electricity and natural gas TSOs (Transelectrica and Transgaz).
- **National Agency of Mineral Resources (ANRM)** organizes tenders and concludes contracts for mineral resource exploration and production, including oil and gas. Extremely weak institution, subordinated to the Prime Minister's office.
- **Romanian National Regulatory Agency (ANRE)**, independent and autonomous body, under the supervision of Romanian Parliament, which is in charge of drafting the secondary legislation for electricity, natural gas and heat.
- **OPCOM** – state-owned market operator. Manages the platform for trading of electricity, natural gas, and issues Green Certificates. It is not the only market operator, since there is also the Romanian Commodity Exchange (Bursa Romana de Marfuri, BRM).
- **Ministry of Environment** issues environmental permits.
- **Environment Guard** has a weak law enforcement capacity.
- **Transelectrica** is the electricity TSO. Authorizes connections to the grid, is in charge of electricity transmission activity, grid maintenance and carrying new investments, issues Green Certificates (GCs) and administers the cogeneration bonus.
- **Transgaz** is the gas TSO.

Energy Demand and Supply

National energy demand and supply

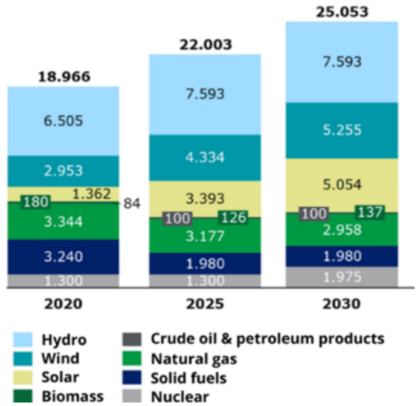
As shown in Figure 5.217, demand is projected to decrease after 2030, but supply as shown in Figure 5.219 is projected to grow by 2030.

Figure 5.217 **Primary energy production, by energy source (2017-2035 forecast, in Mtoe)**



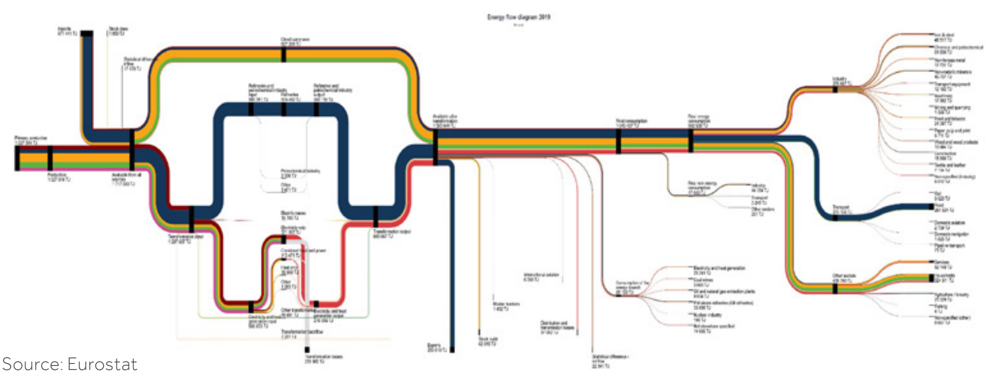
Source: INECP 2020

Figure 5.219 **Expected development of net installed capacity by source (in MW)**



Source: INECP 2020

Figure 5.218 **Romania energy balance for 2019 in Terajoule (TJ)**

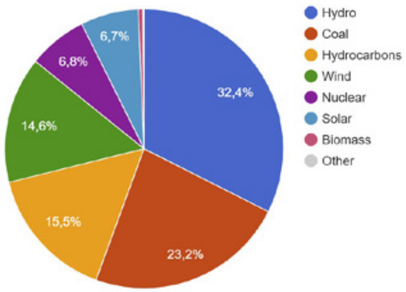


Source: Eurostat

Electricity mix

Presently, Romania has a well-balanced electricity mix, with the highest installed capacity in hydro (6,704 MW equivalent to 32.4% of the total installed capacity), followed by coal (4,787 MW, 23.2% of total installed capacity), and by natural gas (3,211 MW, 15.5% of total capacity). In terms of installed capacity, wind comes 4th (with 3,024 MW, and a 14.6% share), and nuclear 5th (1,413 MW, 6.8%), and solar is 6th (1,392 MW, 6.7%). See the figure below.

Figure 5.220 **Installed electricity capacity per source (in % share)**

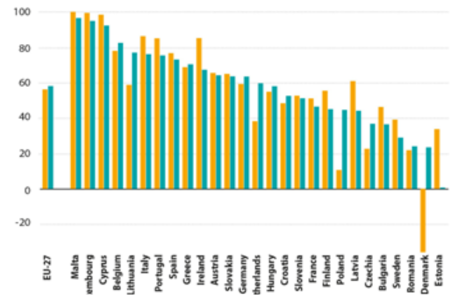


Source: ANRE, March 2020

Degree of energy dependence

Romania constantly ranks as the third (and second, after Brexit) least energy dependent country in the EU. While the EU-27 average rate of energy dependency was 58% in 2018, Romania's dependency rate was a little over 20%. Along with Denmark and Estonia, Romania was among the top 3 countries with the lowest energy dependence in 2018. This is due to rich domestic resources such as hydro, coal, natural gas, nuclear and renewables. This is, to a large extent a legacy of the communist regime, which pursued a policy of self-reliance and diversification. Contemporary Romania has further built on this favorable inherited mix, with efforts focusing on developing new RES capacity (mostly other than hydro) and on shrinking the share of coal in the energy mix. However, this good fortune also led to complacency with regard to developing new hydrocarbon resources, as evident by the 8-year delay in the development of the Black Sea natural gas resources discovered in 2012. The decrease of coal's share in the energy mix is still unfolding, but it is mostly the result of the pressure from Brussels and of the EU energy and climate policy, not an autonomous or conscientious decision made by the Romanian government.

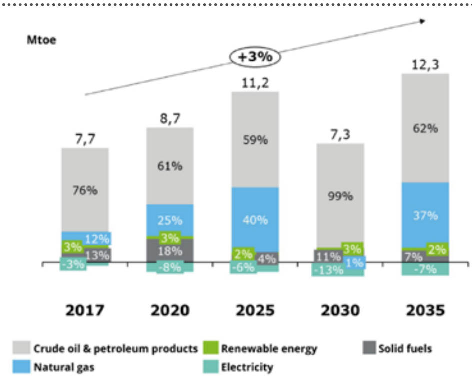
Figure 5.221 **Energy dependency rate (%), 2018 vs. 2000**



Source: Eurostat

Despite Romania's favorable current situation, overall energy dependence is expected to increase by 2025, then to drop in 2030 (due to an increase in domestic gas production) and increase once again by 2035.

Figure 5.222 **Net imports by energy source (2017-2035 forecast)**



Source: Romania's INECP, 2020

The energy import forecast for 2017-2035, as shown in Fig. 8, suggests that Romania will remain an electricity exporter until 2035. This, however, is already no longer the case, as in 2019 Romania became a net electricity importer. Whether Romania will be an importer or exporter of electricity will depend on how fast new generation assets will come online.

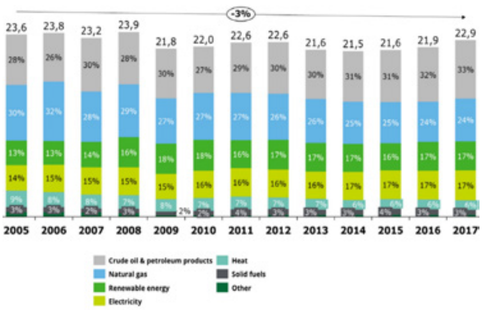
Most likely, until 2025 Romania will be a net electricity importer, and will revert to electricity exporter status only after the additional generation capacity is put in place (see plans for new power plants detailed in the "Cogeneration" and "Energy investment outlook" sections).

The Energy Market

Oil and Petroleum Products

(a) Oil supply and demand

Figure 5.223 **Structure of final energy consumption by energy source (2005-2017)**



Source: Romania's INECP, 2020

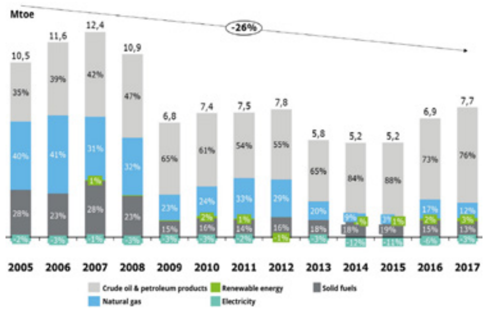
Between 2005 and 2017, oil and petroleum products accounted for 30% (on average) of final energy consumption – the largest share of all energy sources, as shown in Fig. 9 on the structure of final energy consumption by energy source.

While overall energy imports decreased by 26% from 2005 until 2017, the share of crude and petroleum products in energy imports doubled during this period (from 35% in 2005 to 76% in 2017). See Fig. 5,224 on net energy imports. At the same time, as Romania exhausts its domestic oil reserves without improving its reserve replacement, the import of crude and petroleum products is likely to go up. The main crude producer in Romania remains OMV Petrom. The company is also the main user of the oil pipeline system (OMV Petrom is Conpet's largest client, accounting for 80% of its revenues). Key Romanian refineries are Petromidia (5 Mt/year refining capacity), Petrobrazi (4.5 Mt/y) and Petrotel - Lukoil (2.7 Mt/y).

(b) Oil imports/dependence

The quantity of energy imports fell in 2009 and never recovered to its pre-2008 level. Net energy imports dropped from 10.9 Mtoe (2008) to 6.8 Mtoe (2009) and hovered around 7 Mtoe during the next decade. Crude and petroleum products (which used to account for 35% of imports in 2005) represented 76% of total energy imports in 2017. On the other hand, the share of natural gas and solid fuels has dropped significantly since its peak years (2005-2008), a trend that is persisting, as shown in Figure 5.224.

Figure 5.224 **Net energy imports, by energy source (2005-2017)**

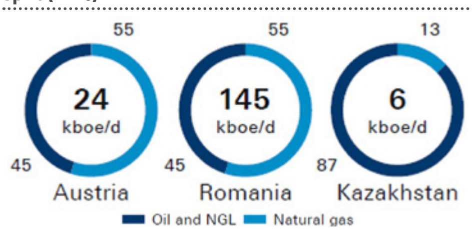


Source: Romania's INECP, 2020

(c) Upstream sector - domestic production and exploration

OMV Petrom remains the largest oil producer in Romania. At the end of 2019, the company operated 193 onshore and offshore production licenses and was active in 10 exploration licenses. Total hydrocarbon production was 145 kboe/d, of which 55% natural gas and 45% crude. Romania remains the most important country in OMV's production portfolio. By comparison, its assets in Austria produce just 24 kboe/d and those in Kazakhstan produce just 6 kboe/d.

Figure 5.225 **OMV production in CEE, plus oil and gas split (in %)**



Source: OMV Factbook 2019

Figure 5.226 **Daily production of OMV in CEE (in kboe/d)**

Although OMV has expanded and now has a global footprint, Romania remains the top hydrocarbon producer (145 kboe/d) in its upstream portfolio, followed by Russia (100 kboe/d), and Norway (87 kboe/d).

Table 5.169 **OMV global hydrocarbon production in 2019, by country and by region (2015-2019)**

Production

In kboe/d

	2015	2016	2017	2018	2019
Central and Eastern Europe	**211**	**202**	**196**	**186**	**176**
Austria	32	28	28	26	24
Romania	170	166	161	153	145
Kazakhstan	9	8	7	7	6
Middle East and Africa	**31**	**27**	**46**	**54**	**70**
Tunisia	8	8	7	5	4
Pakistan[1]	13	10	8	4	–
Libya	0	1	25	30	30
Yemen	2	–	–	3	5
Kurdistan Region of Iraq	7	7	7	8	9
United Arab Emirates	–	–	–	5	22
North Sea	**48**	**71**	**79**	**75**	**87**
Norway	47	70	79	75	87
United Kingdom	1	1	0	–	–
Russia	**–**	**–**	**9**	**100**	**100**
Asia-Pacific	**20**	**18**	**17**	**13**	**55**
New Zealand	20	18	17	13	42
Malaysia	–	–	–	–	13
Total	**310**	**318**	**348**	**427**	**487**

Source: Romania's INECP, 2020

Table 5.169 underscores the central role that Romania continues to play in OMV's upstream portfolio. Despite OMV's diversification and market entry in other geographical areas (Middle East, Africa, Asia Pacific, Kazakhstan, Russia), so far none of these new assets have outstripped the hydrocarbon production OMV has in Romania. However, there has been a visible decline between 2015-2019 in OMV's Romanian hydrocarbon production: from 170 kboe/d in 2015 to 145 kboe/d in 2019.

As Table 5.170 shows, Romania holds a prominent place among OMV's major licenses in various countries.

Table 5.170 **OMV's major licenses in Romania, Austria, Kazakhstan, Norway and Russia**

Country	Working interest[2,3]	Type of production and license	OMV operatorship	Primary type of hydrocarbon[4]
Romania				
Asset Crișana	100%	Production	Operated	Oil and NGL
Asset Muntenia Vest	100%	Production	Operated	Oil and NGL
Asset Muntenia	100%	Production	Operated	Oil and NGL
Asset Oltenia	100%	Production	Operated	Natural gas
Asset Moesia	100%	Production	Operated	Oil and NGL
Asset Moldova	100%	Production	Operated	Oil and NGL
Asset Petromar	100%	Production	Operated	Natural gas
PEC Țicleni	100%	Production	Non-operated	Oil and NGL
PEC Turnu	100%	Production	Non-operated	Oil and NGL
PEC Timiș	100%	Production	Non-operated	Oil and NGL
Asset Hunt JOA	50%	Production	Non-operated	Natural gas
Neptun Deep	50%	Appraisal	Non-operated	Natural gas
Austria				
AREA 1 Nord	100%	Production	Operated	Oil and NGL
AREA 2 Matzen	100%	Production	Operated	Oil and NGL
AREA 4 Hochleiten	100%	Production	Operated	Oil and NGL
AREA 36	100%	Production	Operated	Natural gas
AREA 5 SüdGAS	100%	Production	Operated	Natural gas
AREA 7 West	100%	Production	Operated	Natural gas
AREA 8 Thann	100%	Production	Operated	Natural gas
Kazakhstan				
Aktas	100%	Production	Operated	Oil and NGL
Tasbulat	100%	Production	Operated	Oil and NGL
Turkmenoi	100%	Production	Operated	Oil and NGL
Komsomolskoye	100%	Production	Operated	Oil and NGL
North Sea				
Norway				
Aasta Hansteen	15%	Production	Non-operated	Natural gas
Edvard Grieg	20%	Production	Non-operated	Oil and NGL
Gudrun	24%	Production	Non-operated	Oil and NGL
Gullfaks	19%	Production	Non-operated	Oil and NGL
Wisting	25%	Appraisal	Non-operated[5]	Oil and NGL
Hades/Iris	30%	Appraisal	Operated	Natural gas
Russia				
Russia				
Yuzhno-Russkoye	24.99%	Production	Non-operated	Natural gas

Operated / Non-operated / Oil and NGL / Natural gas

Note: Romania's and Austria's licenses are clustered into asset units due to their large number (more than 190 in Romania, more than 150 in Austria).

For the exact location of the 12 cluster assets in Romania, please see map on next page.

5

Map 5.55 **OMV Petrom's oil & gas assets (as of December 2019)**

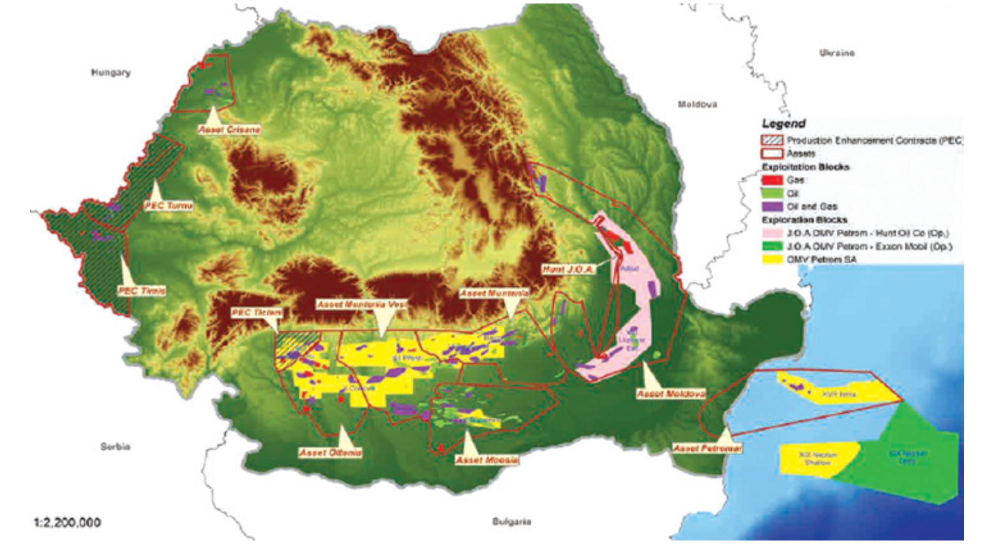


Table 5.171 **OMV production in 2019 in Romania and Kazakhstan, oil and natural gas**

	Oil and NGL		Natural gas		Total
	mn t	mn bbl	bcm	mn boe	mn boe
Romania	3.34	24.06	4.42	28.92	52.97
Kazakhstan	0.27	2.07	0.05	0.30	2.37
OMV Petrom Group	**3.61**	**26.12**	**4.47**	**29.22**	**55.35**

In Romania, 26% of Petrom's total domestic production is based on EOR techniques. Heavy oil accounts for 36% of the total crude and NGL production.

Since 2010, OMV Petrom concluded partnerships with international companies, such as PetroSantander and Expert Petroleum, for production enhancement. The production enhancement contracts (PECs) cover 22 mature fields in total, which are clustered in 3 groups: PEC Timis, PEC Turnu, PEC Țicleni. Under this type of contract, the contractors finance and take over operations, but OMV remains the sole titleholder of the concession and owner of the hydrocarbon production and assets. Total production under PECs was 7.3 kboe/d in 2019, of which 3.9 kboe/d from PEC Țicleni, 1.2 kboe/d from PEC Turnu and 2.2 kboe/d from PEC Timis.

Under the Joint Operations Agreement with Hunt Oil (50% OMV Petrom, 50% Hunt Oil as operator) production was 1.4 kboe/d (OMV Petrom share). Total production under PECs and the Joint Operations Agreement with Hunt Oil was 8.7 kboe/d, representing juts 6% of OMV Petrom's domestic production in Romania.

(d) Downstream and midstream sectors infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

The main players in the downstream sector are OMV Petrom (the main player on the Romanian fuels market with a 32% market share also in the region), Rompetrol (8% market share in Romania) and Lukoil.

OMV Petrom operates one refinery in Romania - Petrobrazi.

Petrobrazi refinery has a refining capacity of 4.5 million tons per year and achieved a utilization rate of 97% in 2019 (up from 85% in 2018). Petrobrazi can process OMV Petrom's entire Romanian equity crude oil. The refinery also has a hydrogen plant on its premises.

Its latest upgrade was the Polyfuel plant, with an investment worth 65 million EUR. The plant allows 90,000 tons of high-octane gasoline and diesel to be obtained through reconversion of LPG and low-grade light gasoline. The unit is "the third of its kind worldwide and the first to convert low-grade light gasoline as well, not just LPG" according to the company annual report for 2019.

OMV Petrom has a network of 793 filling stations in the Black Sea region, most of which (556 stations) are located in Romania. It has 94 filling stations in Bulgaria and 81 in Moldova.

Table 5.172 **Number of filling sations per country at the end of period**

Romania	556
Moldova	84
Bulgaria	94
Serbia	62
Total	**793**

In terms of sales, OMV sold 5.5 million tons of refined products in 2019, of which 2.8 million tons were retail sales. Retail sales in Romania were 2.4 million tons in 2019. The company boasts to have achieved a record throughput in Romania: 5 million liters per filling station in 2019.

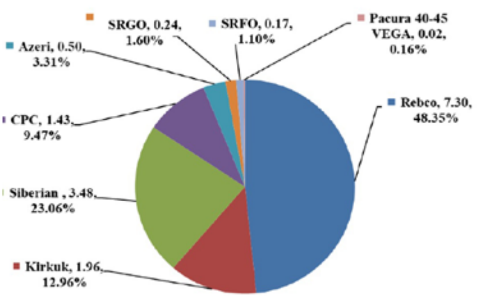
Rompetrol operates 2 refineries in Romania: **Petromidia Refinery** (in Constanta) and **Vega** refinery (in Ploiesti) and a **petrochemical plant** (in Navodari, Constanta).

Petromidia refinery is the largest in Romania and one of the most modern in the Black Sea region with a Nelson complexity index of 11.4. Ranked 9th among 250 refineries in Europe and Africa by Wood MacKenzie in 2018. The refinery has the highest white product output in the region (86.2%) and a utilization rate of 90% (higher than the average European utilization rate of 83%).

In addition, it has the highest in the region capability to extract sulphur from oil, obtaining exclusively Euro 5 fuels. KazMunayGaz (KMG) has invested 1.6 billion USD since it took over the company, of which 1 billion USD was invested in Petromidia. The largest project was the upgrade and increase of its capacity from 3.5 Mt/year to 5 Mt/year, a project worth 450 million USD.

As shown in Fig. 5.228, the total feedstock processed in 2019 was 6.33 million tons while gasoline production was 1.37 million tons, jet group production was 406 ktons, diesel production 2.93 million tons (highest ever).

Figure 5.227 **Petromidia refinery: feedstock structure in 2019 (in 000 tons/day, and % it represents)**



The yield for diesel was 48.5% and for fuels (gas, diesel, Jet, automotive LPG fuel) is 75.4%. The finished products are sold in the domestic market as well as in the international market.

The main export markets, by petroleum product, are:

- gasoline: Greece, Georgia, Lebanon, Bulgaria, Moldova, Turkey;
- diesel: Greece, Bulgaria, Moldova, Turkey, Georgia;
- jet fuel: Moldova, Georgia, Bulgaria, Albania;
- petcoke: Turkey, Moldova, Ukraine, Serbia, Hungary;
- sulphur: Egypt, Ukraine.

Table 5.173 **Petromidia refinery: structure of deliveries in 2019**

OIL PRODUCTS	TOTAL DELIVERIES	DELIVERIES					
		DOMESTIC *		EXPORT		TRANSFER	
	[tons]	[tons]	[%]	[tons]	[%]	[tons]	[%]
Gasoline	1,376,024	357,266	25.96	1,018,758	74.04		
Gasoline for chemical use	232,965	0	0,00	27,779	11.92	205,186	88.08
Petroleum	406,180	316,369	77.89	78,826	19.41	10,986	2.70
Auto diesel fuel	2,927,053	1,890,099	64.57	1,036,954	35.43	0	0.00
Fuel oil	182,204	6,604	3.62	29,256	16.06	146,343	80.32
Vacuum distillation	152,561	0	0.00	0	0.00	152,561	100.0
Propylene	284,304	284,304	100.0	0	0.00	0	
Liquefied Petroleum Gas LPG	264,804	178,678	67.47	86,131	32.53	0	
Petroleum Coke	54,147	78	0.14	57,069	99.86	0	
Petroleum Sulphur	72,682	39,396	54.20	0	0.00	33,286	45.80
Other Products	1,376,024	357,266	25.96	1,018,758	74.04	0	
TOTAL	**5,955,930**	**3,072,857**	**51.59**	**2,334,773**	**39.20**	**548,362**	**9.21**

** The quantities delivered for domestic consumption include the petroleum products marketed on the domestic market. The deliveries to Vega and Petrochemical are included under the heading "transfer"*

Most of the gasoline produced at Petromidia is exported (1 million tons or 74%) and only 357,000 tons (26%) is supplied to the domestic market. In contrast, most of the diesel fuel (1.9 million tons, or 65%) and most of the LPG (178, 678 tons or 68%) is sold in the domestic market. Overall 52% of the finished products are sold in the domestic market, and 40% are exported. Motor fuels (gasoline, diesel, LPG) account for 80% of total finished products sales.

Vega refinery is the oldest processing unit in Romania (115 years). It is the only domestic producer of bitumen and hexane. Its total feedstock in 2019 was 436 kt while hexane production was 92 kt and bitumen production was 120 kt. Vega works in perfect synergy with the Petromidia refinery.

Table 5.174 **Vega refinery: structure of petroleum products deliveries in 2019**

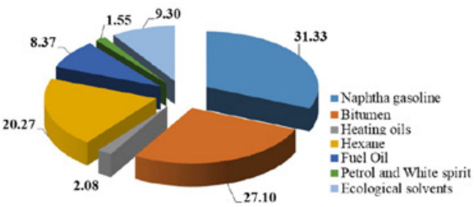
Group of products	TOTAL DELIVERIES 2019		DOMESTIC		EXPORT	
	[tons]	% of total sales	[tons]	%	[tons]	%
Naphtha gasoline	138,953	31.33	48,823	35.14	90,130	64.86
Bitumen	120,199	27.10	119,219	99.18	980	0.82
Heating fuels	9,247	2.08	9,247	100.00	-	-
Hexane	89,889	20.27	3,110	3.46	86,779	96.54
Heavy fuel oil	37,120	8.37	36,833	99.23	287	0.77
Petroleum and White spirit	6,890	1.55	4,926	71.50	1,964	28.50
Ecologic solvents	41,228	9.30	679	1.65	40,549	98.35
Total	**443,526**	**100.00**	**222,837**	**50.24**	**220,689**	**49.76**

Vega focuses on the production of solvents (SE 30/60, n-Hexane, white spirit)), naphta, heating fuels, normal road bitumen and modified bitumen (Fig. 5.229). Two thirds of the naphta gasoline produced at Vega is exported. The entire bitumen production (119,219 tons or 99%) and 100% of the heating fuels (9,247 tons) is used in the domestic market, as is 99% of the heavy fuel oil. On the other hand, ecological solvents go mainly to export (98%).

The main export markets for petroleum products produced at Vega are:

- naphta: Hungary, Slovakia, Czech Republic, Poland, Spain;
- hexane: India, Turkey, Ukraine, Bulgaria, Russia;
- ecological solvents: Germany, Cyprus, Spain, Ukraine, Hungary, Moldova;
- white spirit: Bulgaria, Moldova;
- fuel oil: Bulgaria;
- bitumen: Bulgaria.

Figure 5.228 **Structure of Vega sales, by product (in %)**



Navodari petrochemical plant is the only producer of polypropylene (PP) and polyethylene (LDPE, HDPE) in Romania.

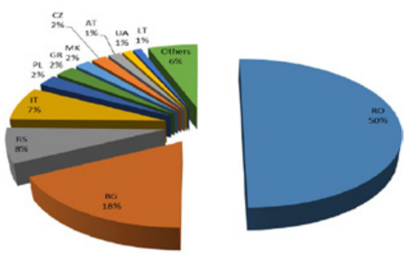
Table 5.175 **Navodari petrochemical plant: structure of polymers deliveries in 2019**

		DELIVERIES			
PRODUCTS	TOTAL DELIVERIES	DOMESTIC		EXPORT	
	[tons]	[tons]	[%]	[tones]	[%]
PP	91,771	40,112	44%	51,659	56%
LDPE	38,121	25,053	66%	13,069	34%
HDPE	3,316	1,101	33%	2,215	67%

Note: PP = polypropylene; LDPE = low density polyethylene; HDPE = high density polyethylene.

In addition to its own products, the petrochemical plant also sells products of high demand in the domestic market (which are not produced there) such as HDPE variants, LLDPE, PVC, or PET. The main markets for polymers (PP, LDPE, HDPE, PET, PVC) are Romania (50%), Bulgaria (18%, Serbia (8%) and Italy (7%), as shown in Figure 5.229.

Figure 5.229 **Polymer Sales by Destination 2019**



Domestic fuel sales:

Rompetrol Downstream distribution segment has 964 points of sale (December 2019) which include its own network of stations plus partner stations and mobile stations. Rompetrol Downstream sold 2.11 million tons of fuel on the Romanian market in 2019, an increase compared to 2018, largely due to a boost in diesel sales. Diesel has the highest share (84%) of the total motor fuels sold by Rompetrol nationwide.

Lukoil

In Europe, the company fully owns 3 refineries (in Romania, Bulgaria and Italy) and holds a 45% share of a refinery in Netherlands as shown in Table 5.176.

Table 5.176 **Lukoil owned refineries in Europe in 2019**

Country	Refinery	Built	Acquired	Refining capacity	Nelson index
Romania	Petrotel-Lukoil	1904	1998	2.7 million tons	10
Bulgaria	Burgas	1964; 1975	1999	7 million tons	13
Italy	Isab	1964	2008 (49%); 2011 (60%); 2012 (80%); 2013 (100%)	14 million tons	10.6
Netherlands	Zeeland (ex-TRN)	1973	2009	3.6 million tons	8.4

Source: compiled by author

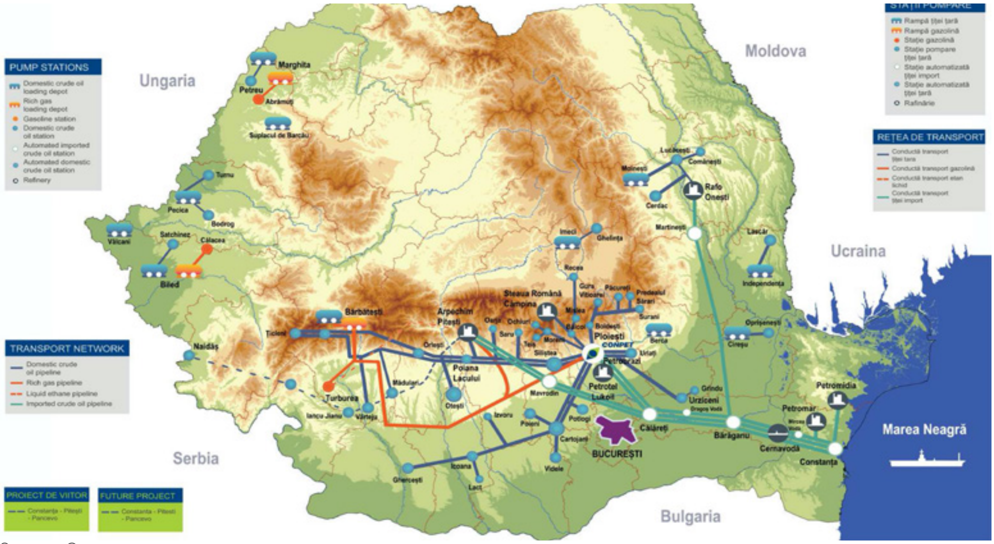
Petrotel-Lukoil is the oldest of these 4 refineries, built in 1904, which is why it was also the first to be modernized. Until 2013-2014, Lukoil's Romanian refinery was the most advanced one in its portfolio of refineries outside Russia (and the only one with a Nelson index of 10 at the time). Following subsequent upgrade and modernization programs in other refineries, this is no longer the case, as the Burgas refinery (Bulgaria) and Isab refinery (Italy) now have a higher Nelson index than Petrotel (in Romania). In terms of refining capacity, Petrotel-Lukoil has the lowest refining capacity (only 2.7 million tons) compared to Burgas (7 million tons) or Isab (14 million tons). Petrotel processes Urals oil and oil produced at Romanian fields. Its refining throughput was 2.485 million tons in 2019.

Table 5.177 **Key figures for Petrotel Lukoil refinery in Romania**

	2015	2016	2017	2018	2019
Refining capacity, mln t/year	2.7	2.7	2.7	2.7	2.7
Nelson index	10.0	10.0	10.0	10.0	10.0
Refinery throughput, mln t	2.237	2.771	2.368	2.723	2.485
Petroleum products output, mln t	2.173	2.709	2.320	2.659	2.368

The refinery is located in Ploiesti, some 55 km away from Bucharest. Crude is delivered to the refinery by railway and via a pipeline from Constanta. Finished products are shipped by railroad and motor trucks.

Map 5.56 **OMV Petrom's oil & gas assets (as of December 2019)**



Source: Conpet

Romania has an extensive crude pipeline system for transporting oil within the country. Romania's crude pipeline system is concentrated almost entirely in the central-southern part (Constanta, Bucharest, the outer Carpathian region). The main gateway for crude import is Constanta. The oil transport system is not connected to any of the neighboring countries and has mostly a domestic purpose. Conpet is the operator of the oil transport system (also referred to as "crude oil, rich gas, condensate and ethane pipeline transport system"). For areas not connected to the transport system, Conpet uses railway tanks.

The National Transport System was built to transport crude from the oil fields to the refineries. The system has 3,800 km of pipelines, out of which 3,161 km are currently used. The system has the following subsystems, grouped according to the transported products:

- **Domestic crude and condensate transport subsystem** (approx. 1,540 km) transports crude oil and condensate produced in OMV Petrom areas to the refineries. The domestic crude oil and condensate production is transported via pipelines, by railway tanks, or combined (rail and pipelines).
- **Rich gas transport subsystem** transports rich gas from the separation units in Ardeal (Biled and Pecica) to Petrobrazi refinery.
- **Ethane transport subsystem** from Turburea ethane separation platform to Arpechim Pitesti refinery. Currently, due to the shutdown of Arpechim refinery, the subsystem is not used, except for one portion of the pipeline which is used to transport condensate from Totea warehouse to Petrobrazi refinery.
- **Subsystem for crude** imports transports crude oil from Oil Terminal Constanta to the refineries in Ploiești, Arpechim-Pitești and Midia.

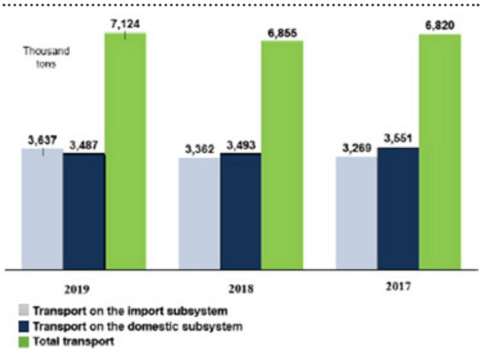
Three quarters of Conpet's revenues come from the domestic transport of oil -and not from the transport of imported oil- despite the fact that the overall quantities are about the same. The total annual volume transported through the oil pipeline system is 7 million tons, which translates into a transport throughput utilization rate of 40%.

Table 5.178 **Conpet: oil volumes transported and revenues (2017-2019)**

Indicators	M.U.	2019	2018	2017
Quantities transported on the domestic subsystem	Thousand tons	3,487	3,493	3,551
Quantities transported on the import subsystem	Thousand tons	3,637	3,362	3,269
TOTAL TRANSPORTED QUANTITIES	**Thousand tons**	**7,124**	**6,855**	**6,820**
Revenues on the domestic transport subsystem	mRON	295.63	290.16	284.89
Revenues on the import transport subsystem	mRON	106.39	90.42	87.47
Total transport revenues	**mRON**	**402.02**	**380.58**	**372.36**

Source: Conpet

Figure 5.230 **Conpet: oil volumes transported in 2017-2019**



Source: Conpet

Oil transport is a natural monopoly activity, therefore Conpet has no competitors. Tariffs are set by ANRM. They are higher for the use of the domestic subsystem than for the import subsystem. There is also a differentiation in tariff value for the import subsystem based on volume.

Table 5.179 **Oil transport tariffs for the domestic subsystem**

Period	Transport tariff (RON/ton)	Approved by NAMR Order no.
January 01st, 2018 - June 18th, 2018	79.75	32/2016
June 19th, 2018 – December 30th, 2019	84.37	117/2018
Starting December 31st, 2019	87.53	427/2019

Table 5.180 **Oil transport tariffs for the import subsystem**

Period	Installments	Arpechim Refinery	Ploiesti Basin (Petrobrazi and Petrotel Lukoil refineries)	Petromidia Refinery	Approved by NAMR Order no.
	Thousand tons/month	RON/ton	RON/ton	RON/ton	
January 1st, 2018 - June 18th, 2018	< 100	38.85	38.00	8.00	32/2016
	>100	16.60	16.00	7.33	
June 19, 2018 30.12.2019	< 120	38.85	38.00	27.00*	117/2018
	>120	16.60	16.00	24.74*	
Starting with December 31, 2019	< 120	40.40	39.50	15.00	427/2019
	>120	17.25	17.00	12.85	

Source: Conpet

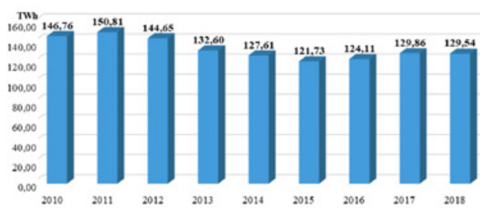
Natural Gas

(a) Natural Gas Supply and Demand

Currently, Romania is the 2nd natural gas producer in the European Union, after Netherlands. Presently, annual domestic production stands at 10 Bcm. Romania is traditionally an onshore gas producer. The most impressive discovery to date – the Neptune gas field in the Black Sea, in 2012 - has not led to an investment decision yet. The first Romanian Black Sea gas may start flowing in 2021 from the Ana and Doina gas fields, part of the Midia project, developed by Black Sea Oil and Gas (BSOG) which will add 1 Bcm/year to the market.

As shown in Figure 5.231, Romania's gas consumption reached a low in 2015 (121.7 TWh), has rebounded since, without however reaching the 2010-2012 levels.

Figure 5.231 **Natural gas consumption in Romania (2010-2018)**

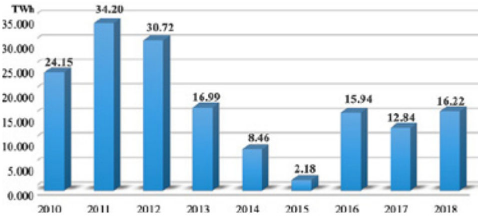


Source: ANRE

Romania's consumption profile is determined by high gas imports during winter and low gas imports during summer (when consumption relies mostly on domestic gas). The highest gas imports in the past decade were recorded in 2011 and 2012, and the lowest gas imports were recorded in 2015 as shown in Figure 5.232.

(b) Natural Gas Imports

Figure 5.232 **Romania's natural gas imports (2010-2018)**



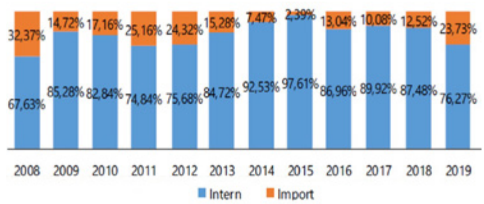
Source: ANRE

Romania achieved full liberalization of its gas market on July 1, 2020. Until June 30, 2020, there was a *de facto* price cap on domestic gas at 68 lei/MWh (€14/MWh). More broadly, the current situation in the gas market is shaped by demand reduction (due to the economic Covid-induced slowdown).

(c) Dependence (%)

It should be noted that, thanks to its sizable indigenous gas production, Romania has the lowest gas import dependency in the region (See Figure 5.233). At present Romania has 44 active concession areas, where the companies involved undertake exploration, development and production activities on the strength of submitted programs approved by ANRM. Map 5.57 shows these active areas.

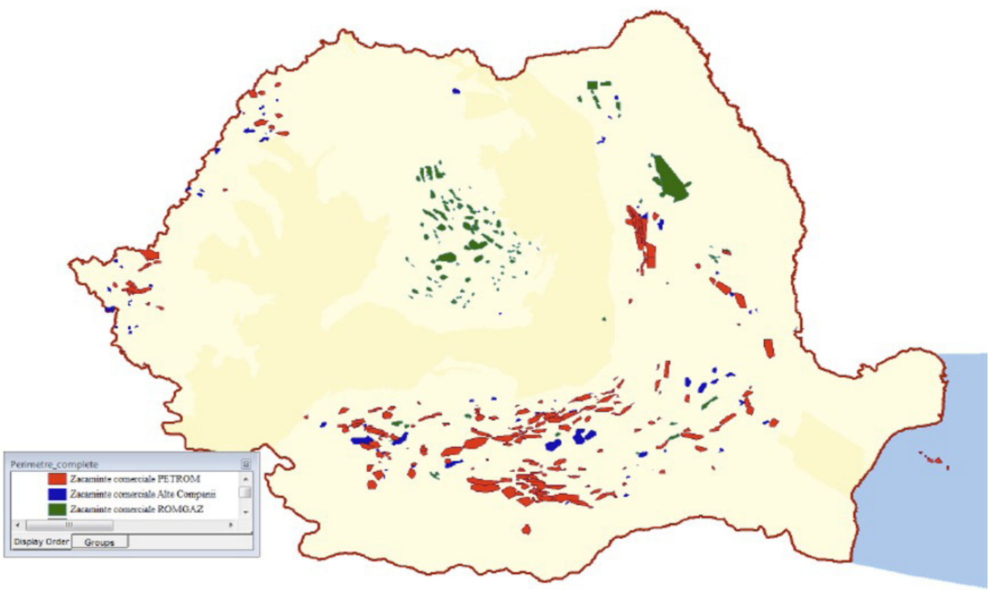
Figure 5.233 **Share of domestic vs. import gas (2008-2019)**



Note: color code: blue = domestic gas, orange = import gas
Source: ANRE (for 2008-2015) and Transgaz (for 2016-2019

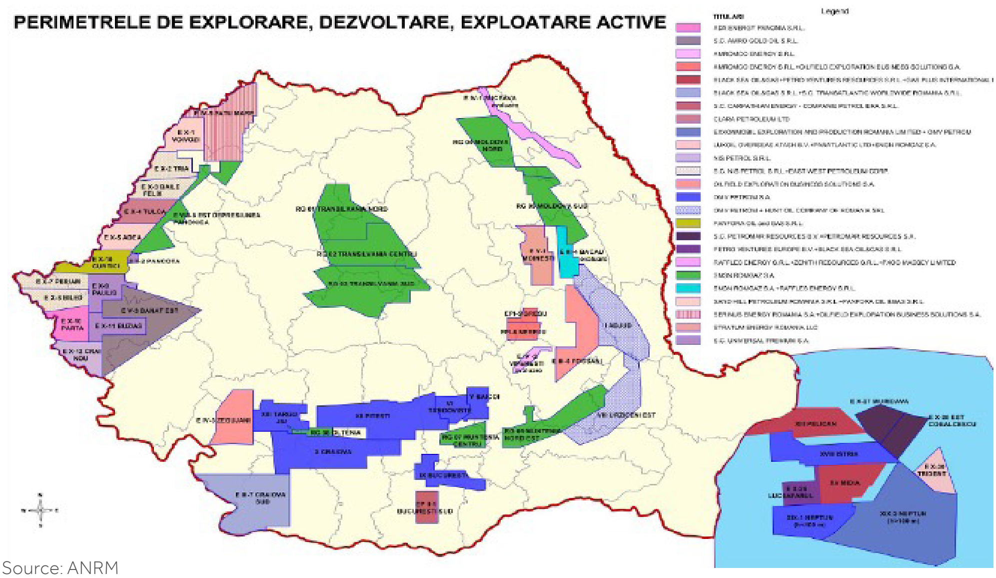
(d) Domestic Production and Exploration

Map 5.57 **Romania: national oil transport system**



Source: ANRM
Note: color code: red = OMV Petrom, green = Romgaz, blue = other companies

Map 5.58 **Romania's Hydrocarbon concession areas**



Source: ANRM

(e) Infrastructure (Pipelines, Storage)

Pipelines

The National Gas Transmission System is a radial-ring system interconnected with the starting points in the deposit area of Transylvania, Oltenia and Muntenia East, and the destination area of Bucharest-Ploiești, Moldova, Oltenia and Central and North Transylvania. Natural gas is transported via gas pipelines and gas supply connections, a network operating at pressures between 6 and 35 bar. The gas network, which is managed by Transgaz as shown on Map 5.59, is connected to Ukraine, Hungary, Bulgaria and Moldova through seven interconnection points as follows:

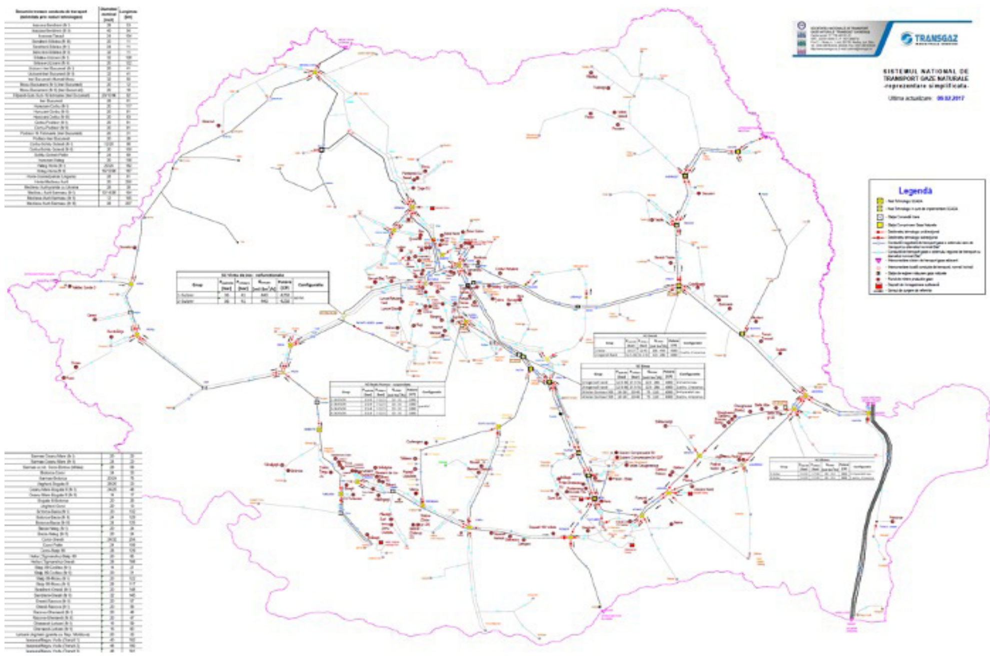
- Medieșul Aurit entry point with annual import capacity of 4 bcm (42.2 TWh) and regime pressure of 70 bar;
- Isaccea entry point with an annual import capacity of 8.6 bcm (90.73 TWh) and regime pressure of 55 bar;
- Isaccea 1/Orlovka 1 with capacity of 6.8 bcm/year. Pressure: 49.5 bar at import, 45 bar at export
- Csanadpalota entry and exit point with an annual import capacity of 1.75 bcm (18.46 TWh), 63 bar pressure, an annual export capacity of 0.087 bcm (0.91 TWh) and annual interruptible export capacity of 0.35 bcm (3.69 TWh). As of October 2019, the import capacity grew to 2.2 bcm/year.

After the completion of phase II of the BRUA gas pipeline, the transport capacity towards Hungary will increase to 4.4 bcm/year.

- Iași-Ungheni exit point, with an annual capacity of 1.5 billion cubic meters (15.8 TWh), 50 bar.
- Giurgiu-Ruse entry/exit point, with annual capacity of 1.5 bcm from Romania to Bulgaria and 0.5 bcm from Bulgaria towards Romania. Pressure: 40 bar at export, 30 bar at import.
- Negru Voda 1/ Kardam with a capacity of 6.4 bcm at export, 55 bar pressure.

Romania's maximum annual import capacity is 14.35 bcm (151.39 TWh). The nominal annual export capacity is 1.58 bcm (16.74 TWh). Physical gas export is possible only with Hungary (Csanadpalota), Bulgaria (Giurgiu-Ruse) and Moldova (Iasi-Ungheni).

Map 5.59 **Romania National Gas System**



Source: ANRM

Table 5.181 **Transgaz investment plan for 2017-2026**

No	Interconnection	Status	Commissioning
1	Interconnection România-Bulgaria	Final Investment Decision (FID)	Dec. 2016
2	NTS development in North-East Romania	Non-FID, advanced stage	2018
3	Interconnection of the NTS with the distribution system and reverse flow at Isaccea	Non-FID (PCI 6.15)	2019
4	New Developments for the Black Sea projects	Non-FID	2019
5	Development of the NTS on the Romanian territory: BRUA	Phase I: FID (PCI 6.24.2) Phase II: Non-FID, advanced stage (PIC 6.25.7)	2020 2020
6	Development of the Southern Corridor on the Romanian territory	Non-FID, advanced stage (PCI 6.24.8)	2020
7	Eastring – Romania	Non-FID (PIC 6.25.1)	2021
8	Extension of BRUA – phase 3	Non-FID (PCI 6.25.3)	2023

Source: SNAM-BCG (2017), ENPG (2018)

Romania's flagship project in the last 5 years (2015-2020) has been the BRUA (Bulgaria – Romania – Hungary – Austria) pipeline. While Hungary has extracted itself from the original route, Romania pressed ahead in completing phase I of the project on its territory. The BRUA project was initially designed along 3 stages, of which only the first one has been realized:

Phase I

- is considered a Security of Supply project (SoS)
- Cost: €478.6 million, of which €179.3 million come from the EU.
- Construction start: June 2018
- Completed: November 2020

• Status: As of now, it is "a pipeline from nowhere to nowhere". The pipeline links the Romanian Black Sea gas to export gas markets in Central and Eastern Europe. It was supposed to carry natural gas (yet to be produced) and transport it through Hungary further to Austria. Hungary has chosen instead to be part of the alternative Russian project (Turkish Stream), making the Romanian gas unnecessary, since Bulgaria, Hungary and Serbia all signed on to the Russian project, making the Romanian leg irrelevant.

Phase II

- Considered a commercial project (will go ahead only if commercially viable)
- Lack of market interest
- Cost: €74.5 million
- Status: cancelled

Phase III – a back-up plan for phase II, in case additional gas volumes require transportation in excess of the volumes shipped West through BRUA stage II. Currently not applicable.

Storage

Romania's current nominal storage capacity is 4.5 bcm /cycle (47 TWh), with a regular use of 3 bcm/cycle (31 TWh). There are two storage operators: Romgaz (Depogaz) and Depomures. There are 6 UGS set up in depleted reservoirs, five of which are operated by Romgaz (total capacity of 2.76 bcm), and only one by Depomures (0.3 bcm). Table 5.182 shows the status of Romania's underground gas storage facilities.

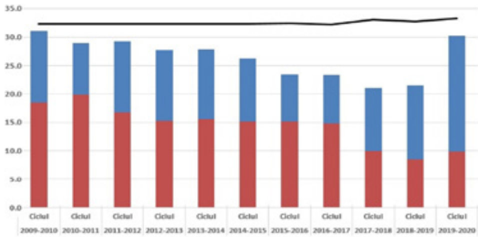
Table 5.182 **Capacity of underground gas storages (UGSs)**

Storage name	Operator	Active capacity (TWh/cycle)	Extraction capacity (GWh/day)	Injection capacity (GWh/day)
Balaceanca	Depogaz	0.5452	13.176	10.98
Bilciuresti	Depogaz	14.3263	152.782	109.13
Ghercesti	Depogaz	1.6343	21.4	21.4
Sarmasel	Depogaz	9.5987	79.035	68.497
Urziceni	Depogaz	4.0168	50.157	33.438
Targu Mures	Depomures	3.1545	29	27
Total		**33.2758**	**345.55**	**270.445**

Source: Transgaz, PDSNT 2020-2029

Storage is not very flexible, as it was mainly developed to deal with seasonal variations, and hence, the rate of injection/extraction is not designed for fast commercial use. Tariffs for gas storage are regulated.

Figure 5.234 **Reserved gas storage capacity (2009-2019)**



Note: color code: red = producers, blue = others, black = technical capacity   Source: Transgaz

As Figure 5.234 shows, in the previous 4 cycles before the last one, storage usage dropped below 25 TWh, and climbed back to 30 TWh in the 2019-2020 cycle, reflecting a wider stock build up and glut in the market. In addition, national legislation now obliges gas suppliers to hold minimum required quantities for each market segment.

(f) Domestic Gas Market

The Romanian gas market is highly concentrated on the production side, it is essentially an oligopolistic market, with 2 big players: Romgaz and OMV Petrom (together they account for 90% of the domestic gas production). The other players are Amromco Energy, Serinus Energy Romania, Stratum Energy Romania, Raffles Energy, Mazarine Energy Romania, Hunt Oil Romania, and Foraje Sonde. It is a less concentrated market on the supply side, with 84 gas suppliers and 31 gas distributors.

Gas transport, storage and distribution is regulated, while the rest of activities are conducted in the free market on a competitive basis. In Romania, households account for up to 30% of gas consumption, while industry and commercial end-users account for 70%. Households in urban areas use natural gas, while in the countryside it is largely biomass

5

(firewood) that is used for heating and cooking. There are 3.6 million residential consumers. Gas supply in the residential sector is dominated by Engie and E.ON, which together account for 90%.

Industry: The non-residential consumers (industry, electricity production, district heating, chemical industry) amount to 200,000. OMV Petrom is an important supplier to large industrial customers and commercial customers (businesses, small industrial customers), but is not present on the residential segment. Both Romgaz and Petrom's domestic production, but also imported gas, supply the chemical industry which is one of the biggest consumers. **Azomures** (the biggest producer of fertilizers, since 2011 owned by Swiss company Ameropa) is now the main industrial **consumer of gas**, especially since Interagro's plants have closed down or have been under restructuring following bankruptcy procedures in the past years.

District heating: CHPs are major users of natural gas, with ELCEN (the main supplier of heat in Bucharest) being the biggest such customer. Romgaz is the main gas supplier for CHPs. Many coal-fired power plants have switched in recent years to natural gas in order to comply with stricter environmental standards. This trend will continue in the coming years, with natural gas displacing coal-fired power generation, especially in cogeneration.

Utilization of natural gas (CH4) in transport is incipient. Despite having domestic gas production, Romania did not give too much thought until now to natural gas as an alternative fuel (as CNG or LNG) for sustainable transport. No LNG re-fueling infrastructure exists to date.

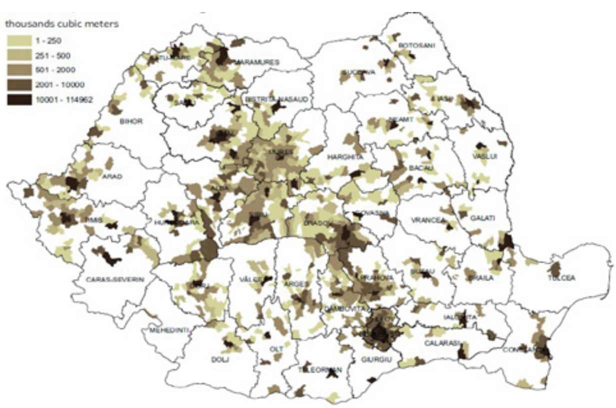
(g) National NG policy - strategic plan

At EU level, there is a major shift away from natural gas under way. Financial institutions (such as the European Investment Bank) have excluded fossil fuel projects (including gas) from future financing, with EBRD and some commerce banks following suit. As climate finance develops further driven by EU's aggressive decarbonization agenda, this will reduce funding opportunities available for gas projects.

In Romania, it took more than 10 years for decision-makers to understand that natural gas is a transition fuel (hence its days are numbered). Therefore, the upcoming decade presents a last window of opportunity to invest in domestic gas related infrastructure. Despite being a gas producer since 1909, Romania's gas grid covers less than half of the country's household use (estimates range between 35% and 40% in terms of household that have access to the gas grid).

The prevailing situation concerning household use is clearly shown on Map 5.60.

Map 5.60 **Consumption of natural gas for household use**



Source: ANRM

In October 2020, Romania's president approved **Law no. 214**, which enacts GEO no. 128/2020 which creates a **National program for connecting the population to the gas grid**. The law creates the possibility for the costs of connecting to the gas grid to be covered by EU funds during 2014-2020 (under LIOP, Axis 8)[4] as well as in the upcoming 2021-2027 period[5]. The funding will support the „transformation of existing natural gas grids into smart gas distribution grids".

In September 2020, the EU Parliament has passed an amendment which would allow EU countries to use the Just Transition Fund also for natural gas projects in coal dependent monoindustrial regions. This keeps the door open for gas as a transition fuel in the next decade.

On the upstream side, 6 years were lost (between 2012-2018) without adopting a fiscal regulatory framework for Black Sea gas development. When finally it was adopted in 2018, the oil and gas companies did not like it and held back on making an investment decision. Furthermore, with the changed global circumstances (gas glut and demand destruction), Exxon wants to exit the Romanian Black Sea, and so does Lukoil. Both are looking to sell their shares in the offshore concession areas where gas discoveries were made.

Onshore, the situation does not look any better. Excessive and haphazard regulation (such as the price freeze at 68 lei for sale of domestic gas to end-consumers in 2019-2020) resulted in over-taxation of domestically produced gas in comparison to imported gas (which was not subject to these additional taxes), and led to an increase of gas imports in 2019 and the shutdown of some domestic gas wells deemed unprofitable (mostly belonging to Romgaz). At the same time, a dash for gas in power generation has been underway since 2015, with more and more CHPs gradually switching from coal to natural gas in Romania.

(h) Planned new projects

The biggest development in natural gas was supposed to be the start of gas production in the Romanian Black Sea, which was expected in 2018. However, 8 years since the gas discovery was first made in Neptune Deep in 2012, no FID has been taken. Exxon wants out of the perimeter and has been looking for two years for potential buyers of its 50% stake. Finally, after much foot dragging and other proposals under consideration, Romgaz submitted a bid to buy Exxon's share of the perimeter for €900 million in early April 2021.

If Romania manages to get its act together and kickstart production of Black Sea gas, that would be the biggest development in the natural gas market.

Solid Fuels

(a) Supply and consumption

In 2020, Romania had 4,787 MW of coal-fired installed capacity which accounted for 23% of its total installed capacity. In its initial INECP (2019), Romania outlined a moderate reduction in net installed coal capacity (from 5.5 GW in 2019 to 3.2 GW in 2030) – a reduction of 2.3 GW in the span of a decade. Retirement of coal-fired capacities started with the write-off of obsolete units (which existed on paper only, labeled as "reserves", but were not functional in practice). Nevertheless, Romania does not yet have an official coal phase-out strategy, with a clear commitment to back away from coal. Instead, the country has an ambivalent position on the issue of coal phase-out. On the one hand, it plans to retire 2.3 GW of coal capacity by 2030, but on the other hand, it shies away from adopting a coal phase-out strategy or making an explicit time-bound commitment, and tends to avoid the topic of coal phase-out in public discussions. This is complicated by the fact that there are regions in Romania (such as Hunedoara, with 1,225 MW installed

[4] The National program financed from EU funds allocated for 2014-2020 will run until December 31, 2023.
[5] The National program financed from EU funds allocated for 2021-2027 will run until December 31, 2029.

coal capacity) where no alternative to coal generation has been put in place yet. Which is why old powerplants have to function partially (at minimum 400 MW) for system stability reasons until the end of 2020, despite being practically bankrupt.

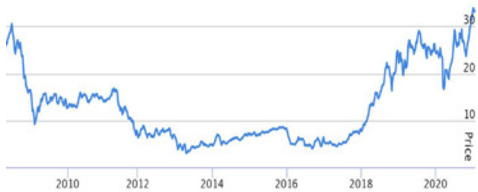
The entire coal production of Romania is used for heat and power generation. Hard coal is mined by Complexul Energetic Hunedoara (CEH) and lignite by Complexul Energetic Oltenia (CEO). Complexul Energetic Oltenia (CEO)'s power plants run entirely on lignite (3,240 MW in total) while Complexul Energetic Hunedoara's power plants run entirely on hard coal (1,225 MW, as shown in Table 5.183.

Table 5.183 **Coal-fired power generation in 2017**

Power supply		2017
Total gross power generation	TWh	64.3
Net power imports (exports)	TWh	(2.9)
Total power supply	TWh	56.0
Power generation from hard coal	TWh	1.2
Power generation from lignite	TWh	15.6
Hard coal power generation capacity	MW gross	1 225
Lignite power generation capacity	MW gross	3 240

The pressure to decarbonize grew in 2018-2020, especially after the price of carbon emissions under the EU ETS jumped significantly, as shown in Figure 5.235. This has put even more pressure on coal-fired power generation. In order to benefit from state-aid, some producers have agreed to restructure completely. This is the case of Complexul Energetic Oltenia which has tabled an ambitious plan to reorganize its assets, by abandoning coal-generation entirely and replacing it with natural gas and renewables in the coming years.

Figure 5.235 **EAU price evolution**

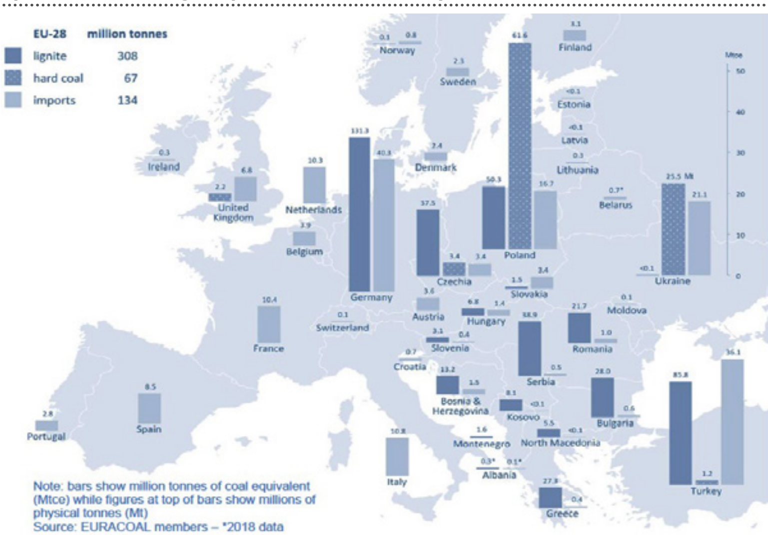


Source: Ember

(b) Local production and exploration

Romania ranks fifth in the EU by domestic coal production (after Germany, Poland, Bulgaria, and Greece) and 7th on the European continent (with Turkey and Ukraine having a larger coal production than Romania). Map 5.61 shows the prevailing situation in Europe and Turkey.

Map 5.61 **Europe: hard coal and lignite production and coal imports in 2019**



Source: ANRM

(c) Deposits

Hard coal resources are estimated at 2,446 million tonnes, of which 11 million are economically recoverable. Lignite resources are estimated at 9,640 million tonnes, of which 280 million tonnes are proven reserves. Almost 90% of lignite is located in Oltenia basin and 80% can be surfaced mined. Table 5.184 shows Romania's coal resources and reserves.

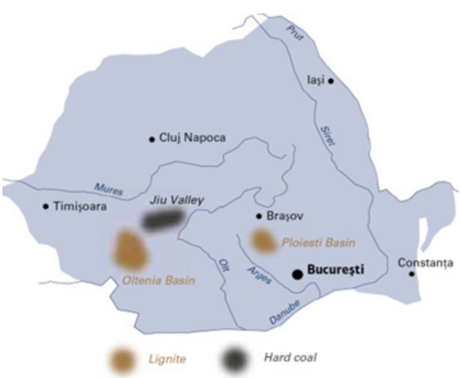
Table 5.184 **Romania's coal resources and reserves**

Coal resources and reserves		as at 1.1.2018
Total resources hard coal	Mt	2 446
Total resources lignite	Mt	9 920
Reserves hard coal	Mt	11
Reserves lignite	Mt	280

The Romanian government agreed in 2011 to close the loss-making mines. The closure targets only unprofitable mines. The following hard coal mines have been closed: Petrila mine (oldest in Romania) in 2015, Paroşeni and Uricani mines in 2017, Lonea and Lupeni (in 2018). Only two hard coal mines are still being exploited: Vulcan and Livezeni (belonging to CEH).

In terms of lignite mines, the following are scheduled to be closed: Rovinari, Husnicioara, Lupoaia, Pesteana (which belong to CEO). Map 5.62 shows the geographic location of the above mines.

Map 5.62 **Location of lignite and hard coal deposits**



Source: Euracoal

(d) Core imports

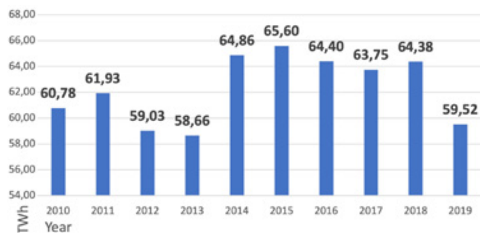
Romania imported 0.9 Mt of coal in 2018. No coal was exported in that year.

(e) Planned new projects: There are no new coal projects under consideration.

Electricity

(a) Electricity supply and demand (in TWh)
Romania's gross electricity production in 2019 was 59.5 TWh – almost the same as a decade ago (60.8 TWh in 2010) as shown in Figures 5.236 and 5.237 which provide further information on electricity consumption patterns.

Figure 5.236 **Actual annual gross electricity production in Romania (2010-2019)**



Source: Transelectrica data

Figure 5.237 **Average net consumption 2017-2019 (MWh/h)**

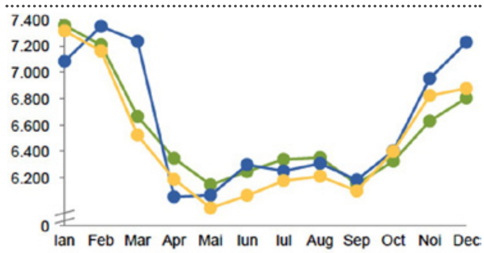


Table 5.185 **Maximum hourly consumption (2017-2019)**

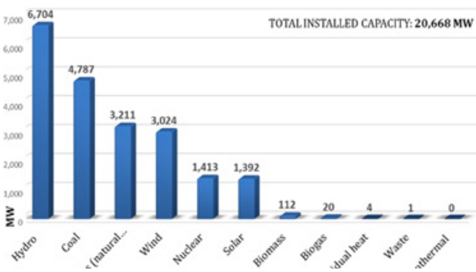
Year	Month	Value (MWh/h)
2017	January	8,940
2018	February	8,920
2019	January	8,812

Source: Transelectrica data

b) Installed Capacity (in MW)

The evolution of Romania's installed electricity capacity is shown in Table 5.186, while Figure 5.238 depicts the installed capacity per source for 2020. The total installed capacity has steadily been decreasing in late years on account of thermal units scale down as RES capacity is moving upwards.

Figure 5.238 **Installed capacity per source (in MW)**



Source: ANRE data, 2020

In terms of installed capacity in MW, hydro has by far the largest capacities, see figure above.

Table 5.186 **Evolution of installed capacity (2017-2019)**

MW	2019	2018	2017
Termo	8.026	11.888	12.029
Nuclear	1.413	1.413	1.413
Hidro	6.704	6.759	6.761
Regenerabile	4.553	4.546	4.535
Total	20.696	24.606*	24.738

Source: Transelectrica
Note: thermal means coal + natural gas

Electricity imports - exports

Table 5.187 **Electricity balance (2017-2019)**

Year	2017	2018	2019
Net domestic production	59.8 TWh	60.7 TWh	56 TWh
Import	3.2 TWh	2.8 TWh	5.5 TWh
Export	6.1 TWh	5.4 TWh	4 TWh
Net domestic consumption	56.9 TWh	58.1 TWh	57.5 TWh

Source: Transelectrica

Tariffs

Electricity transport is a natural monopoly activity and tariffs are regulated. As of January 2021, ANRE set the following tariffs for electricity transmission as shown in Table 5.188:

Table 5.188 **Transmission tariffs in 2021**

Tariff type	Lei/ MWh	€/MWh
Average tariff for electricity transport	20.55	4.22
TG – tariff for injecting power in the grid	1.3	0.27
TL – tariff for extracting power from the grid	19.22	3.95
Tariff for system services	11.96	2.46

Source: ANRE Order no. 214/ December 9, 2020

(c) Cross-border interconnections:

There are 16 cross-border electricity interconnections which are summarized in Table 5.189.

Table 5.189 **Cross border power lines**

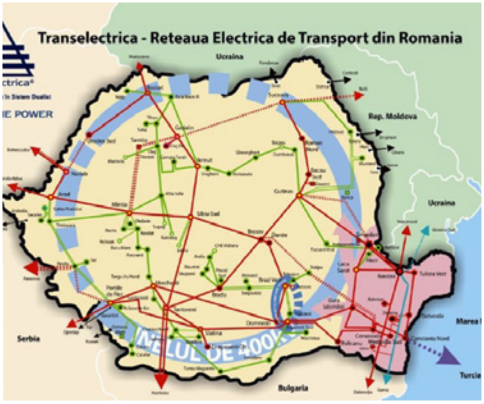
Order no.	Border	OEL interconnection
1	Bulgaria	400 kV Ţânţăreni – Kozlodui OPL
2	Bulgaria	400 kV Stupina – Varna OPL
3	Bulgaria	400 kV Rahman – Dobrudja OPL
4	Serbia	400 kV Iron Gates – Djerdap OPL
5	Serbia	400 kV Reşiţa – Pancevo OPL
6	Serbia	110 kV Jimbolia – Kikinda OPL
7	Serbia	110 kV Gura Văii – Sip OPL
8	Serbia	110 kV Ostrovu Mare – Kusjak OPL
9	Hungary	400 kV Arad – Sandorfalva OPL
10	Hungary	400 kV Nadab – Bekescsaba OPL
11	Ukraine	400 kV Roşiori – Mukachevo OPL
12	The Republic of Moldova	400 kV Isaccea – Vucăneşti OPL
13	The Republic of Moldova	110 kV Stânca – Costeşti OPL
14	The Republic of Moldova	110 kV Cioara – Huşi OPL
15	The Republic of Moldova	110 kV Ţuţora – Ungheni OPL
16	The Republic of Moldova	110 kV Falciu – Goteşti OPL

Source: Transelectrica, ETG Development Plan for 2018–2027, Annex B-2, Electricity Transmission Grid in Romania, http://www.transelectrica.ro/web/tel/transport-detalii

(d) **Planned new projects focus mostly on the domestic level.** Transelectrica considers as priority the following projects to be completed by 2030:

- 400 kV OPL Nădab – Oradea South;
- 400 kV OPL Iron Gates - Reșița and extension of 220/110 kV Reșița Station by building a new 400 kV station;
- 400 kV OPL in double circuit Cernavodă – Stâlpu, with an entry/exit circuit in Gura Ialomiței station;
- 400 kV OPL in double circuit Reșița - Timișoara - Săcălaz, including construction of the 400 kV Timișoara station;
- 400 kV OPL in double circuit Smârdan – Gutinaș;
- 400 kV OPL in double circuit Timișoara – Săcălaz - Arad, including the construction of the 400 kV Săcălaz station and extension of the 400 kV Arad station.

Map 5.63 **Romania Electricity Transmission network**



On account of these projects Romania aims to achieve a 15.4% rate of interconnectivity by 2030.

Renewables

(a) Overview of the sector's development

Significant investments (€8 billion) made in the renewable energy sector during 2010-2015 led to 5 GW of new renewable energy sources (RES) capacity being added. It must be mentioned however that, in RES Romania started from a strong position due to the existence of a large hydro base. To date, its hydro capacity remains the largest in the country (6,704 MW of installed capacity). On the other hand, geothermal capacity continues to remain underdeveloped (below 1 MW). No significant new RES capacities were added during 2017-2019.

To date, most of the investments in new RES capacities built in Romania were carried out by foreign companies, with little to no interest (until 2020) from the large state-owned enterprises (SOEs), with the exception of Hidroelectrica.

The biggest investors in wind are CEZ (600 MW in total), Enel Green Power Romania (499 MW), Energias De Portugal Renovaveis - EDPR (386 MW), Verbund Wind Power Romania (226 MW), STEAG (108 MW), IKEA (123 MW), Engie (98 MW), and Lukoil (84 MW). CEZ sold its Romanian assets to Macquire Infrastructure and Real Assets (MIRA), an Australian investment fund in a transaction valued over €1 billion, a record amount for Romania, where only three other M&A transactions ever exceeded this threshold (Erste-BCR; Vadofone-Connex, and Rompetrol - KMG).

The biggest projects in solar energy belong to Samsung (98 MW in total), GPBS Solaris 48 (56 MW), Green Vision Seven (46 MW), Enel Green Power Romania (34 MW), XPV (23 MW), EDPR (22 MW), Eye Mall (20 MW) and WDP Development Romania (12 MW).

The largest investors in small hydro projects are Hidroelectrica (38 MW in total), Elsid SA (36 MW), CEZ through TMK Hydroenergy power (22 MW), Vienna Energy Forta Naturala (20 MW), MHC Water Power (15 MW), Electrocarbon (14 MW) and Luxten Lighting Company (9 MW).

The largest biomass projects belong to Bioenergy Suceava (30 MW), Holzindustrie Schweihofer (21 MW), Bio Electrica Transilvania (20 MW), and Egger Romania (15 MW).

Currently, **Romania has no offshore wind capacity.** Moreover, there is a significant onshore wind potential that remains unexploited, estimated at 9.0 GW of the 12 GW overall.

With the exception of Hidroelectrica, the majority of the state-owned enterprises (SOEs) have largely been indifferent to renewable projects during the peak years of RES development in Romania (2011-2015). This is now changing. The new government policy is to encourage diversification of the power generation portfolio of SOEs, moving away from the hitherto business model of power generation by one energy source which existed between SOEs (Hidroelectrica for hydro generation, Romgaz for natural gas, Oltenia and Hunedoara for coal). This trend will only speed up in the context of the Green Deal and as funding for green infrastructure projects is becoming available in the coming years.

(b) Latest legislation, incentives and national RES policy

Romania's Integrated National Energy and Climate Plan (INECP) aims for a share of 30.7% from RES in gross final energy consumption by 2030. This target is a step-up from 27.9% which was included in the first draft (December 2018). In its final version Romania's INECP (April 2020), Romania increased the target to 30.7% (a level still considered conservative by the EC, which recommended a RES target of at least 34%). In order to achieve this target, an additional 6.9 GW of renewable generation should be added by 2030, compared to 2015. Fortunately, Romania possesses a generous potential when it comes to RES. According to a study by Deloitte, Romania's renewable potential by RES type is:

- 54 GW in solar (19 GW industrial, 35 GW rooftop)
- 16 GW in wind (12 GW onshore, 4 GW offshore)
- 11 GW in hydro

The two main non-technical barriers that, if removed/solved, could allow additional RES development are:

- allowing conclusion of Power Purchase Agreements (PPAs)
- the possibility to use EU funds for power grid consolidation, in areas where new RES projects are located, in order to facilitate integration of RES into the grid.

(c) Installed capacity per source (in MW)

Table 5.190 **Accredited RES-E producers (2018)**

RES technology	Number of producers	Installed capacity	Share of accredited RES-E
Wind	66	2,961 MW	62%
Small hydro (<10 MW)	102	341 MW	7%
Solar PV	576	1,359 MW	28%
Biomass	28	124 MW	3%
Total	772	4,785 MW	100%

Source: ANRE National Annual Report for 2018

(d) Planned new major projects

There is an interest in offshore RES potential signaled by Hidroelectrica (the largest RES player, entirely state-owned) which stated its intention to build 300 MW of offshore wind, as well as from the banking sector.

Romgaz (a traditional natural gas producer) is planning to build 250 MW of RES capacity in the next five years (2020-2025), according to the National Investment and Economic Recovery Plan of July 2020.

The largest coal producer, Complexul Energetic Oltenia (CEO), has tabled a restructuring plan that aims to "decarbonize" its electricity production by building 8 PV parks (totaling 700 MW) and 2 small hydro projects (12 MW), but also replacing all of its coal-fired generation capacity with natural gas-fired units by 2026.

Energy Efficiency and Cogeneration

Romania aims to achieve **10 million toe of cumulative energy savings** between 2020 and 2030. Investments will be concentrated in 2020-2025, with effects to be felt from 2025 onwards. Table 5.191 shows the targeted energy savings for 2021-2030.

Table 5.191 **Target energy savings for 2021-2030 based on avg. final energy consumption (2016-18)**

Year	Annual energy savings										TOTAL
2021	0.11										0.11
2022	0.11	0.11									0.23
2023	0.11	0.11	0.16								0.39
2024	0.11	0.11	0.16	0.18							0.57
2025	0.11	0.11	0.16	0.18	0.18						0.76
2026	0.11	0.11	0.16	0.18	0.18	0.18					0.94
2027	0.11	0.11	0.16	0.18	0.18	0.18	0.32				1.26
2028	0.11	0.11	0.16	0.18	0.18	0.18	0.32	0.34			1.60
2029	0.11	0.11	0.16	0.18	0.18	0.18	0.32	0.34	0.34		1.95
2030	0.11	0.11	0.16	0.18	0.18	0.18	0.32	0.34	0.34	0.34	2.29
TOTAL cumulated energy efficiency in the period 2021-2030[20]											10.12

Source: INECP

Romania plans to seriously focus on buildings and has drafted a National long-term strategy for building renovation (2020-2050), which was approved by the government in November 2020. The strategy targets an annual increase of energy savings from 0.03 Mtoe (in 2021) to 0.83 Mtoe (in 2030) – a total of **3.4 Mtoe in energy savings in the building sector** is foreseen for the next decade. Table 5.192 shows the energy efficiency targets for the residential sector for 2021-2030.

Table 5.192 **Energy efficiency in residential sector to be achieved in the period 2021-2030 [Mtoe]**

Year	Energy saving in the residential sector										TOTAL
2021	0.03										0.03
2022	0.03	0.04									0.07
2023	0.03	0.04	0.05								0.12
2024	0.03	0.04	0.05	0.05							0.17
2025	0.03	0.04	0.05	0.05	0.06						0.23
2026	0.03	0.04	0.05	0.05	0.06	0.08					0.31
2027	0.03	0.04	0.05	0.05	0.06	0.08	0.11				0.42
2028	0.03	0.04	0.05	0.05	0.06	0.08	0.11	0.12			0.54
2029	0.03	0.04	0.05	0.05	0.06	0.08	0.11	0.12	0.14		0.68
2030	0.03	0.04	0.05	0.05	0.06	0.08	0.11	0.12	0.14	0.15	0.83
TOTAL cumulated energy efficiency in the residential sector in the period 2021-2030											3.4

Source: World Bank, INECP

The National long-term strategy for building renovation (2020-2050) considered 3 scenarios for building renovation which differ in terms of renovation speed, in comparison to the baseline (current annual renovation rate of the building stock of just 0.5%). Scenario 1 assumes a gradual increase of annual renovation rate over the next 3 decades. Scenario 2 assumes an aggressive increase of the annual renovation rate in the first decade (2020-2030). Scenario 3 assumes a relative constant annual renovation rate of 3-to-3.6% over the entire period. The various scenarios are shown in Table 5.193.

Table 5.193 **Scenarios for building renovation in 2020-2050**

	Annual renovation rates 2021-2030	Annual renovation rates 2031-2040	Annual renovation rates 2041-2050
Baseline scenario	0.50 %	0.50 %	0.50 %
Scenario 1	Gradual increase from 0.53 % to 1.56 %	Gradual increase from 2.22 % to 4.78 %	Gradual increase from 4.85 % to 6.41 %
Scenario 2	**Gradual increase from 0.69 % to 3.39 %**	**3.79 %**	**4.33 %**
Scenario 3	3.13 %	3.24 %	3.62 %

Source: World Bank, INECP

The strategy ultimately chose Scenario 2 which was included in the *National Integrated Energy and Climate Plan* that Romania submitted to the European Commission in 2020. The implications and required investments to achieve scenario 2 are summarized in the Table 5.194.

Table 5.194 **Scenario 2 of building renovation**

Types of buildings	Category	Area [million m²]	Buildings [number]	Investment [million EUR]	Energy savings [million toe]	CO_2 reduction [million tonnes]	Increased renewable energy share [million toe]
Residential – Single-family residences	Rural	10.57	162 475	1 736.87	0.17	0.04	68.63
	Urban area	9.39	102 120	1 449.88	0.14	0.11	39.77
Residential- Multi-family condominium	<= ground-floor + 4 floors	21.62	21 124	2 791.47	0.11	0.47	24.96
	> ground-floor + 4 floors	44.04	23,471	4 877.24	0.36	1.41	50.64
Education	Educational establishments	4.24	4 361	874.84	0.03	0.14	14.81
Health	Hospitals	1.61	161	318.33	0.01	0.06	5.28
	Other	1.07	14 324	192.52	0.01	0.02	3.11
Administrative offices		1.35	1 539	236.55	0.01	0.03	4.41
Commercial	Hotel	0.04	73	9.38	-	0	0.18
	Restaurants/cafes	0.12	2 394	27.05	-	0	0.50
	Shops	1.31	7 686	269.40	0.01	0.6	5.03
Total		95.36	339 728	12 783.53	0.83	2.34	217.31

Source: Romania's long-term renovation strategy for 2020-2050

According to the strategy, the investment requirement to achieve scenario 2 is estimated at 12.8 billion EUR. The funding for energy efficiency programs could come from:

- State budget or EU funds: 5 billion EUR, of which 3 billion EUR non-reimbursable grants;
- Reimbursable grants/loans: 6-to-9 billion EUR;
- Owners' co-financing: 1.8 billion EUR.

The following years will present an auspicious period for energy efficiency projects in Romania, with a variety of funding instruments available for all types of green projects. A general overview of the main European financing channels is provided in Table 5.195.

On top of the funding it receives for the 2021-2027 under the classic EU budget (EU Multiannual Financial Framework), Romania is earmarked to receive €30 billion from the Recovery and Resilience Facility. A part of these resources will be channeled towards building renovation.

Table 5.195 **Overview of main EU funds available to Romania in 2021-2027**

Program	Amount	Comment
Cohesion Policy Funds (ERDF, ESF+, Cohesion Fund)	€29.2 billion	Does not include sums under Connecting Europe Facility.
Recovery and Resilience Facility	€30 billion (approx.)	€13.8 billion of which will be grants.
Just Transition Fund	€3.5 billion	Amount was increased in September from €1.7 billion
Modernization Fund	€3 billion	approximation
ETS auction revenue	€0.7 billion	Revenues from auctioning of allowances under the EU Emission Trading System (ETS); approximation.

On April 7, 2021, the Romanian government approved the National Recovery and Resilience Plan (NRRP), the final version of which will be submitted to the European Commission by May 31, 2021. Building renovation is included under pillar I (Green Transition) and named "Renovation Wave – Fund for green and seismic renovation" (I.5). Its initial negotiating budget is €2.2 billion. Renewable energy is also part of pillar I (Green Transition), and is titled "Renewable energy and energy efficiency" (I.6.) and is allocated an initial negotiating budget of €1.3 billion. However, the numbers in the NRRP are not final yet, and are change following the feedback received from the European Commission.

(d) Cogeneration: Regulatory framework, installed capacity

Romania has a cogeneration bonus (introduced by GD 1215/2009). It is a support scheme that was approved by the European Commission as state aid and became operational on April 1, 2011. The bonus is granted upon request, for electricity produced by high efficiency cogeneration units, which must be included in an approved producers list. The bonus can be granted also to producers who replace, on the same site, old capacities with new ones. The scheme was amended in 2016 to extend also to cogeneration units of less than 1 MW. The state aid is granted for operation and is meant to cover the difference between costs and revenues, allowing a rate of return (RoR) of maximum 9%. It is granted for maximum 11 years, until the end of 2022.

The level of the bonus is set annually by ANRE. The bonus has a reference value for each fuel used as feedstock (coal or natural gas). Its value is adjusted annually based on the following factors: average price of fuel, average price of CO_2 certificate, average price of electricity on DAM, and inflation. In case of overcompensation, a producer can be granted a bonus which is lower than the reference bonus. The contribution for cogeneration is collected from all electricity consumers as a unitary tariff applied on the electricity bill. This contribution is not applied to exported electricity (exemption as of July 2014). In 2019, the value of the bonus was 11.86 lei/MWh in the first semester and 15.64 lei/MWh in the second. The value of the cogeneration bonus for the first half of 2021 was set at 17.12 lei/MWh, valid from January 1, 2021 until June 30, 2021. The bonus is not granted to capacities that have been completely depreciated. The maximum capacity that can benefit from the support scheme over its duration is 4,000 MW. Once this limit is reached, only new capacities (that replace existing ones) can be granted support, in excess of this limit. In 2020, the number of companies that benefited was 36, as shown in Table 5.196.

Table 5.196 **Accredited cogeneration assets for 2020**

Company	CHP/ location	Total installed capacity	Total high efficiency capacity	Of which eligible for the bonus
Electrocentrale Galati	CET Galati	375 MW	45.4 MW	45.4 MW
Veolia Energie Iasi	CET Iasi II	100 MW	51.81 MW	51.81 MW
	CET Iasi I	4.4 MW	4.4 MW	4.4 MW
Veolia Energie Prahova	CET Brazi	288.04 MW	104.43 MW	104.43 MW
Complexul Energetic Hundeoara (CEH)	Mintia – unit 3	210 MW	36.9 MW	36.9 MW
	Paroseni	150 MW	26.4 MW	26.4 MW
CET Arad	CET / Arad	50 MW	33.73 MW	32 MW
Electrocentrale Bucuresti				
(ELCEN Bucharest)	CET Bucuresti Sud	200 MW	187.2 MW	187.2 MW
	CET Bucuresti Vest	186.25 MW	186.25 MW	186.25 MW
	CET Grozavesti	100 MW	71.83 MW	71.83 MW
	CET Progresu	150 MW	128.46 MW	128.46 MW
Thermoenergy Group	CET Bacau	24.95 MW	24.95 MW	24.95 MW
Complexul Energetic Oltenia (CEO)	CET Craiova II	300 MW	106.55 MW	106.55 MW

Termoficare Oradea	CET Oradea	145 MW	62.24 MW	62.24 MW
Cogen powerplant Oradea	46 MW			
CET Govora SA	CET Govora	200 MW	62.79 MW	62.79 MW
Electro Energy Sud SRL	Cogen powerplant			
Giurgiu	17.6 MW	17.6 MW	17.6 MW	
OMV Petrom SA	CET Petrom City	4.54 MW	4.54 MW	2.72 MW
Colterm Timisoara	CET Freidorf	1MW	1MW	1MW
	CET Buzias	1MW	1MW	1MW
	CET Dunarea	1MW	1MW	1MW
ENET Focsani	CET Focsani	8MW	13.6 MW	13.6 MW
	13.6 MW			
SC CET Grivita SRL	CET Grivita Bucuresti	11.4 MW	5.4 MW	5.4 MW
R.A.G.C.L. Pascani	CT 5/ Pascani	0.69 MW	0.55 MW	0.55 MW
SC Colonia Cluj-Napoca Energie SRL	CT 3 Gheorgheni	0.58 MW	0.58 MW	0.58 MW
	CT 8 Gheorgheni	0.21 MW	0.21 MW	0.21 MW
	CTZ Somes Nord	3.1 MW	4.65 MW	4.65 MW
		1.55 MW		
SC Rulmenti SA Barlad	CET	11.99 MW	11.99 MW	5.07 MW
SC UATAA Motru SA	CET	5.5 MW	4.52 MW	4.52 MW
SC BEPCO SRL	CET Nord/Brasov	20.17 MW	20.17 MW	20.17 MW
	CET Metrom/ Brasov	6.71 MW	6.71 MW	6.71 MW
	CET Noua/ Brasov	2.68 MW	2.68 MW	2.68 MW
	CET Nord 2/ Brasov	13.19 MW	13.19 MW	13.19 MW
SC Vest-Energo SA	CET Militari / Bucuresti	6.09 MW	22.96 MW	22.96 MW
		8.07 MW		
		8.8 MW		
SC Servicii Comunale SA Radauti	CET Radauti	7 MW	7 MW	7 MW
SC Ecogen Energy Buzau	CET	6.09 MW	6.09 MW	6.09 MW
SC Modern Calor SA	CET Botosani	8.8 MW	8.8 MW	8.8 MW
ContourGlobal Solutions	CET Ploiesti	6.08 MW	6.08 MW	5.53 MW
SC Compa SA	CET / Sibiu	3.1 MW	3.1 MW	3.1 MW
Urbana SA	CET/ Sibiu	0.95 MW	0.48 MW	0.48 MW
Tereos Romania SA	CET/Ludus	6 MW	3.17 MW	0.55 MW
Politehnica University	CET/ Bucharest	1.67 MW	1.67 MW	1.29 MW
Petrotel-Lukoil	CET PetrotelLukoil/Ploiesti	66 MW	15.24 MW	7.81 MW
Prefab SA	Work point Calarasi	5.4 MW	5.4 MW	4.45 MW
Petrocart SA	Petrocart/			
Piatra Neamt	1.8 MW	1.8 MW	0.28 MW	
Poligen Power Energy SRL	CT Tudor III/ Miercurea Ciuc	4 MW	4 MW	4 MW
Donau Chem SRL	Donau Chem CHP/ Turnu Magurele	20.25 MW	12.79 MW	3.58 MW
Electroutilaj SA - Campina	Electroutilaj CHP/ Doicesti	1.06 MW	0.44 MW	0.44 MW
Soceram SA - Campina	Soceram CHP/ Doicesti	1.06 MW	1.06 MW	1.06 MW

Source: ANRE, Annex to president's decision no. 585 of 08.04.2020

(e) Planned new major projects

The current support scheme (cogeneration bonus) ends in 2022. Romania wants to extend it, and has submitted a proposal to the EC in this regard. If approved, the new support scheme will apply as of March 2022. The new support scheme should be optimized since the previous one failed to attract any new investments in high efficiency cogeneration since 2015.

It is expected that the new conditions will be stricter and much more difficult to comply for older cogeneration units. It is largely believed that the 2011 support scheme was used more to cross-subsidize and keep on life support older capacities (of Complexul Energetic Hunedoara, CEO, ELCEN Bucharest, ELCEN Galati, CET Govora), instead of serving its primary purpose – that of incentivizing the construction of new cogeneration units. The lack of investments in any new capacities after 2015 is a case in point confirming that the 2011 support scheme was highjacked and redirected to serve another purpose (i.e.: delay reform and artificially keep alive outdated generation capacities). In the past year (2019), under pressure to decarbonize and move away from coal, many new cogeneration projects have been announced. Most of the planned capacities are natural gas-fired ones. The largest investment in such capacities is expected to be made by Complexul Energetic Oltenia (CEO) – which alone will account for 1,400 MW of the new installed gas-fired capacity. Table 5.197 shows the status and plans for gas-fired capacities.

Table 5.197 **Planned gas-fired capacities (selection)**

Program	Amount	Owner	Status and plans
CCGT Iernut	430 MW	Romgaz	To be completed by June 2021
CCGT Mintia	400 MW	Romgaz	Feasibility study; could be operational by 2022
Craiova 2	200 MW	CEO	Feasibility study; operational by 2024
Isalnița	800 MW	CEO	Coal-to-gas switch; operational by 2025
Turceni	400 MW	CEO	Coal-to-gas switch; operational by 2025
ALRO	467 MW	ALRO, Romgaz	n/a. 300 MW for Alro's own consumption, 100 MW earmarked for sale on the power market
Halanga	150 MW	Romgaz, GSP	Proposal, MoU signed in September 2020
CCGT Midia	73 MWe	Rompetrol Group	Funded through the Romanian-Kazakh investment fund; deadline n/a
Titan	50 MW	Titan Power SA	deadline n/a.

Note: CEO = Complexul Energetic Oltenia

The Iernut CCGT (430 MW), a Romgaz project initiated in 2013 and still not completed, has had a rocky evolution. Romgaz signed a contract for a turn-key project with a JV made up of Duro Felguera (Spain) and Romelectro (largest Romanian contractor) in 2016.

The project is the first greenfield investment made by the Romanian state (Romgaz is a majority state-owned company) in the past 30 years. The project was meant to mark Romgaz's entry into a new market (electricity production). Estimated at €268 million (without VAT), the contract has experienced cost and time overruns. Things are advancing so slow that Romgaz announced it wants to cancel the contract altogether (currently under discussion with the JV). However, we could use the cost of Iernut (€300 million) as proxy for building 400 new MW, to estimate the cost of adding 3,000 MW of new generation capacity to be at least €2 billion until 2030.

Energy Investment Outlook

The investment requirement in the energy system (only on the demand side) until 2030 was estimated back in 2018 to be €20 billion on average (with a minimum of €15 billion and a maximum of €30 billion).

This estimate was made *before* the Green Deal, so it does not reflect the new EU level of ambition for clean energy. It is, therefore, safe to conclude that the updated investment requirement should be at least **€28-30 billion**, that being a conservative (a minimum) figure to include all investments made (private, public and EU-funds) and distributed as follows by sector:

- RES and storage: €15-17 billion (could go as high as €20 billion if offshore wind takes off)
- Grids (electricity, heat, natural gas): €3 billion
- Buildings: €4 billion
- Nuclear: €4 billion
- «Natural gas-fired generation: €2 billion

Table 5.198 **Estimated investments by energy sector in Romania until 2030**

Sector	Technology type	Capacity	Comment
Nuclear	CANDU (unit 3 of Cernavoda NPP)	700 MW	Estimated investment of **€3.5-4 billion** for unit 3 of Cernavoda NPP, to be put in operation by 2030-2031. Construction start planned for 2024
Hydro	units>10 MW	1,000 MW	Total targeted new capacity in all RES is 6.9 GW by 2030. Estimated investment requirement: **€15-17 billion**
RES	Wind + PV	5,900 MW	
Natural gas	CCGT+CHP	3,000 MW	of which 1,400 MW (gas-fired CCGTs) will belong only to Complexul Energetic Oltenia (CEO) Estimated investment requirement: **minimum €2 billion**
	grid development	n/a	
Energy efficiency	Building renovations	100,000 buildings	**€4 billion**

Source: compiled by author

In the version of the National Recovery and Resilience Plan adopted on April 7, 2021, energy is allocated €4.1 billion: €2.2 billion (building renovations), 1.3 billion (RES and energy efficiency), €600 million (natgas and hydrogen infrastructure). An additional €6-7 billion is available for clean energy projects under the Modernization Fund. Another source of funds is the MFF 2021-2027.

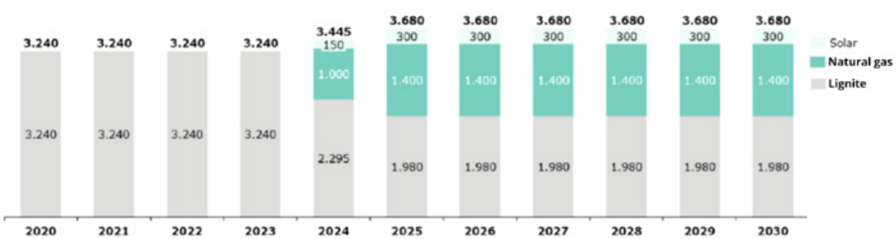
Nuclear

The latest available study estimated the construction cost for both Cernavoda NPP units (number 3 and 4) at €7 billion, meaning €3.5 billion per each unit. The figure has to be updated, but it is realistic to assume €4 billion/unit, given the cost inflation associated with nuclear projects.

Coal phase-out

Although not spoken of explicitly, with no official national calendar for retiring coal generation, with no commitment to a clear deadline, and no coal phase-out strategy, Romania will nevertheless go through this process. In fact, it already is. In February 2020, the Romanian government received the approval from the European Commission to grant a €251 million loan to Complexul Energetic Oltenia (CEO) – the largest coal-fired electricity producer - to help the company buy CO_2 certificates. The cost of CO2 certificates went up significantly in the past 2 years (accounting for 41% of the company turnover in 2018, and 45% in 2019). The loan was to be repaid in 6 months. Since this did not happen, the company opted to send the Commission a restructuring plan (meant to restore profitability). This is how the Decarbonization Plan of Complexul Energetic Oltenia came to be written. If carried out, it will be one of the most significant developments in power generation in the next decade. Currently entirely coal-based (all 3,240 MW), Complexul Energetic Oltenia (CEO) plans to reduce its coal-fired generation to 1,980 MW and add 1,400 MW of natural gas and 300 MW of solar by 2030 – a decarbonization of 54% of its generation assets in just 10 years. The bulk of the current coal capacity will be replaced by natural gas and renewable assets (mostly solar).

Figure 5.239 **Forecast for installed power (in MW) at Complexul Energetic Oltenia (2020-2030)**



Source: The 2020-2030 Development and decarbinisation plan of CE Oltenia

Natural gas

It is positioned to become the largest fuel in power generation over the next decade. There is a total of at least 3,000 MW worth of new projects announced/planned, such as:

- Romgaz CCGT at **Iernut** (430 MW);
- new 200 MW gas-fired block at **Craiova 2**, i.e.: construction of a combined cycle gas-fired high-efficiency cogeneration unit (CCGT) to supply heat to Craiova city and to economic operators (i.e.: Ford), which is to replace the current lignite-fired capacities of 2 x 150 MW;
- new 400 MW unit (CCGT) at **Turceni**, which will replace a current 300 MW lignite-fired capacity at Turceni (project of Complexul Energetic Oltenia);
- two new 400 MW units (CCGT) at **Ișalnița** which will replace unit 7 and 8 (two lignite-fired units of 315 MW each) - project of Complexul Energetic Oltenia;
- new CCGT at **Mintia** (400 MW), in the North-West (a Romgaz project);
- new unit of 70 MW in Midia (project of Rompetrol);
- a CCGT unit at Grozăvești (Elcen project);
- a CCGT unit at **Bucharest South**, of approx. 200 MWe and 200 MWt (Elcen project);
- a gas-fired cogeneration capacity at Progresu (Elcen project);
- upgrade of **Bucharest West** in order to extend its lifespan/implementation of a new combined cycle unit of approximately 186 MWe and 170 Gcal/h.
- CCGT at Halanga (RES, CCGT + hydrogen).

Renewables

The estimate for investments of €15-17 billion is based on a number of assumptions. In the last decade Romania added some 5 GW of new renewable capacity at a cost of €8 billion. Romania targets an additional 6.9 GW by 2030, which should cost up to €11 billion, assuming traditional RES areas (onshore wind and solar). If offshore wind is added into the mix (which is more expensive), this figure can be even higher (€20 billion). At the moment, Romania's wind capacity is situated exclusively onshore.

But the Black Sea in general is considered to hold significant potential for offshore wind: according to the World Bank, 453 GW of technical offshore wind potential – 269 GW for bottom-fixed and 166 GW for floating offshore wind. In addition, Europe published its Offshore Renewable Energy Strategy in November 2020. Banks are keen to finance offshore wind in Romania. Hidrolectrica, the state-owned hydro producer, already announced its plans to build 300-500 MW of offshore wind projects. There is currently no regulatory framework for offshore wind, however the Romanian Parliament is debating a draft Offshore Wind Bill. Furthermore, Romania's National Integrated Energy and Climate Plan (INECP) in its current version does not foresee any offshore wind development, but this can change in 2023 (next document update).

Offshore wind projects will require grid reinforcement in Dobrogea (already operated at capacity in this area), or investment in new power lines to allow the uptake of the new electricity produced offshore. The next decade is also likely to bring about the first electricity storage projects in Romania. Proposals for such projects have already been submitted in response to the call for projects conducted for the Modernization Fund (10d mechanism), under which some € 6-7 billion can be accessed specifically for RES, storage and grid modernization projects (including power lines). Therefore, the estimated investment of €15-17 billion in renewables by 2030 is the sum of the €11 billion (for traditional RES projects) plus an allowance of minimum €4 billion and maximum €6 billion for electricity storage and offshore wind development projects as well as any RES-related grid reinforcement costs.

It is important to note that all these are estimates. There are no guarantees as to which projects will be implemented eventually. Romania has a wish-list, but in the end a lot will depend on the financiers (IFIs, EIB, European Commission) who have a say in project selection (which projects can secure funding). And a lot will depend on timely project execution.

SERBIA

Serbia

Economic and Political Background

Serbia's GDP slid at a milder pace of 1.1% year-on-year in the final quarter of 2020, following the 1.4% contraction tallied in the third quarter. On a seasonally-adjusted quarter-on-quarter basis, economic growth waned markedly in Q4, slowing to 2.2% from the previous period's 7.2% increase. Taking the year as a whole, the economy shrank 2.5% in 2020, contrasting 2019's 4.2% expansion and marking the first contraction since 2014.

The fourth quarter's softer annual contraction largely came on the back of a rebound in the external sector. Exports of goods and services bounced back in Q4, growing 2.1% year-on-year (Q3: -8.5% y-o-y). In addition, imports of goods and services rebounded in Q4, growing 0.8% and contrasting Q3's 2.7% decline.

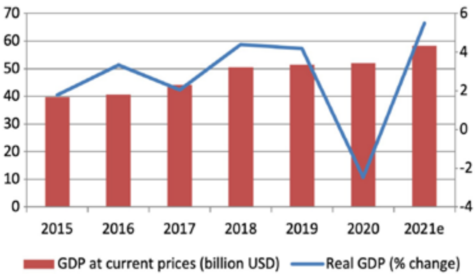
Meanwhile, on the domestic front, private consumption fell 2.7% in the fourth quarter - a sharper drop than the third quarter's 1.1% contraction - likely reflecting the tightening of restrictions amid a resurgence in Covid-19 cases. On the other hand, government spending bounced back, growing 4.6% in Q4 (Q3: -1.1% y-o-y), while fixed investment dropped at a milder pace of 4.1% in Q4 (Q3: -4.5% y-o-y).

Economic growth is forecast to return this year as activity rebounds amid the relaxation of restrictive measures. Moreover, the reopening of foreign economies will boost external demand. That said, the outlook is clouded by lingering downside risks amid uncertainty over the evolution of the pandemic, a rise in unemployment and the phasing out of some relief measures. IMF estimates that Serbia's GDP will expand by 5.5% in 2021, significantly higher than -2.5% in 2020.

The year 2020 was expected to bring further increase in Aleksandar Vučić's power after the parliamentary elections.

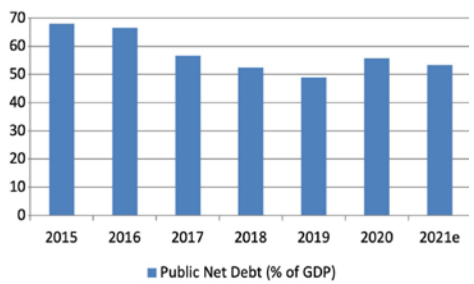
This was complicated by coronavirus pandemic, but with careful management, weakness of the opposition and some luck, achieved anyway. At the end of the previous year, Vučić looked forward to the third "victory over coronavirus" without parliamentary opposition and at least temporarily relieved from pressure over Kosovo issue.

Figure 5.240 **Serbia's GDP and its annual GDP growth**



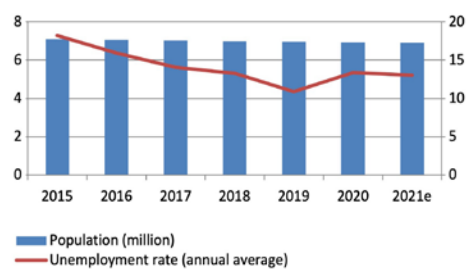
Source: IMF World Energy Outlook (October 2020)

Figure 5.241 **Serbia's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.242 **Serbia's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

National Energy Policy

Serbia's economy is strongly impacted by market forces, but the state's influence remains significant in certain areas that require long-term approach and exhibit broad (socio-economic) implications.

In Serbia the state is still the key player in the energy sector. The national energy policy and development strategy of the Republic of Serbia are formulated at central government level and adopted by the National Assembly.

Legal commitments under the Energy Community Treaty, the EU accession process and the Paris Climate Agreement (2017) need to be converted into actions, within the transition roadmap and the further structural transformation of the energy sector.

All national goals, activities and measures in the energy sector are in line with the objectives of the Energy Strategy of Energy Community, which implies creating a competitive and integrated energy market, attracting investment in the energy sector and ensuring safe and sustainable energy supply. Serbia's coal-based energy sector is under pressure to adapt to new political priorities and the new decarbonized energy landscape.

In view of the three components of EU's energy policy, i.e. security of supply, competitiveness, and sustainability, Serbia as an EU accession country will have to harmonize its energy and climate policies.

The new upcoming obligation (2018) including the preparation of National Energy and Climate Plan (NECP) should cover the period from 2021 to 2030 with the intention of achieving agreed 2030 targets set by Energy Community. The NECP is currently under preparation and is planned to be submitted to the EnC by the end of 2021. All subsector strategies will have to merge in the NECP. EU Commission is expected to propose the 2030 targets for the Energy Community in the first half of 2021.

Improving energy efficiency and decarbonizing the Serbian energy system is a capital-intensive process that essentially involves the substitution of fossil fuels. From the transition perspective, natural gas can provide near-term benefits when replacing more polluting fuels. Scaling up the utilization of renewable energy sources is important not just for power, but for the heating and transport sectors also.

In general, Serbia faces a unique dual transition: transition towards decarbonized society and transition from centralized state-controlled systems to open and competitive markets.

Policies and policy measures in Serbia in general are defined by Laws and other documents, which in most cases include strategies and action plans. The main characteristic of the current Energy Law adopted in December 2014 (Official Gazette 145/2014) is the abolition of monopolies and the introduction of market competition in all energy activities and transposition as provided by the Third Energy Package.

National energy policy is elaborated in more detail through the Energy Sector Development Strategy for the period 2015-2025, with projection up to 2030, the Implementation Program of the Energy Development Strategy for the period 2017 to 2023 and the annual Energy Balance of the Republic of Serbia.

The Strategy is a document outlining the energy policy and energy sector development planning and it is adopted by the National Assembly for a period of at least 15 years. The Implementation Program establishes the conditions, manner, dynamics and measures to implement the Strategy for a period of up to six years.

The Ministry of Mining and Energy (MoME) is responsible for preparing the country's annual energy balance. Consequently, the Energy Balance defines the needs for energy and energy products, sources to provide the required quantities, and the required level of reserves. The Energy Balance is adopted by the government, not later than late December of the current year for the following year.

Serbian Governmental Institutions

The National Parliament adopts energy related legislation, approves Energy Sector Development Strategy and appoints the Council members of the Energy Agency of the Republic of Serbia (AERS).

The Government, as the top executive political body, determines conditions for supply and delivery of energy products (electricity, natural gas and oil), as well as intervention measures in the event of the major disturbances in the energy market. Government adopts the Energy Sector Development Strategy and secondary legislation, decides on launching tendering procedures for the construction of energy facilities (following proposals of the Ministry of Mining and Energy).

The Ministry of Mining and Energy (MoME) is responsible for state administration related to mining, energy, and energy balance of the Republic of Serbia, together with power, gas and oil industry development. The Ministry is in charge of formulating the country's energy policy, energy sector development strategy, energy related legislation and secondary legislation concerning security of supply, energy efficiency and utilisation of renewable energy sources. The Ministry monitors the implementation of the Strategy and development of legal framework within the energy sector. It is responsible for introducing energy-related legal norms of the EU and Energy Community into the legal system of the Republic of Serbia.

The Regulatory Authority - Energy Agency (AERS) is the regulatory authority established with the purpose of improving, directing and supervising the electricity and natural gas markets based on the principles of non-discrimination and efficient competition, by creating a stable regulatory framework, as well as ensuring high standards of service in energy supply. Agency adopts and monitors implementation of methodologies, technical and market rules, tariffs, certificates and prices for regulated market activities. Agency also plays an important role in the work of the Energy Community institutions and offers support to other institutions on national and international levels. In future the competences of AERS will have to be extended to include a complete set of regulatory powers and objectives foreseen under the Third Energy Package, particularly the right to carry out investigations, impose measures to promote competition and proper energy market functioning.

Local municipal authorities have competences in the field of heat, energy efficiency and renewable energy use. They cooperate directly with the citizens, and have a very important role in motivating and promoting rational energy use. They are in charge of energy planning and energy balance at the local level.

PE Serbian Electricity Transmission System and Market Operator (EMS), with main activities in electricity transmission, transmission system control and organisation of electricity market. PE EMS is 100% owned by the Republic of Serbia. In 2015, EMS established SEEPEX - Electricity Exchange in partnership with EPEX SPOT, France.

PE Electric Power Industry of Serbia (EPS), 100% owned by the Republic of Serbia performs activities of electricity generation, trade and supply of electricity, coal production, steam and hot water production, rivers and lakes hydropower utilisation. After the envisaged restructuring measures had been realised, PE EPS became a joint-stock company in 2020. In 2015, EPS established EPS Distribution with its main activity of electricity distribution and distribution system operation.

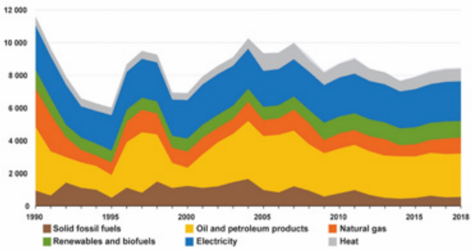
PE Srbijagas holds licenses for natural gas supply, public gas supply, distribution and storage. The transmission operators are the newly formed companies Srbijagas-Transportgas, Yugorosgas-Transport and Gastrans. The expected unbundling in market activities of Srbijagas is ongoing.

PE Transnafta is the public company established by the Government of the Republic of Serbia in 2005 for the purpose of carrying out pipeline transportation of crude oil and oil derivatives. The company is also licensed for trade and storage of oil and petrol derivatives.

Energy Demand and Supply

Today, Serbia faces serious challenges when it comes to harmonization of its Energy and Climate policy in a sustainable way.

Figure 5.243 **Serbia – Final energy Consumption 1990-2018 (ktoe)**



Source: Eurostat

Serbia has survived the last 30 years in very turbulent circumstances. Civil war and partition of the former Yugoslavia, economic blockade (1992-2002), NATO bombing (1999) and the perennial problem with the province of Kosovo and Metohija.

Figure 5.243 shows declines and fluctuations in energy consumption that result from these historical circumstances. Serbia's economy and industry have not yet reached the 1990 development level.

Security of energy and fuel supply to Serbia's energy market is reliable and still optimal owning to the considerable reserves of domestic coal and some reserves of oil and natural gas. Coal is and will continue for some time to be a relevant energy source in Serbia's primary energy supply

Table 5.199 **Serbia - Primary Energy Consumption (Mtoe)**

Primary Energy Consumption	2015	2016	2017	2018
GROSS INLAND CONSUMPTION - TPES	15.054	15.668	16.023	15.802
PRIMARY ENERGY PRODUCTION	10.862	10.791	10.577	10.116
IMPORT	5.733	6.183	6.962	7.148
EXPORT	1.473	1.431	1.439	1.569
STOCK CHANGES & BUNKERS	-0.068	0.125	-0.077	0.107
NET IMPORT	4.260	4.752	5.523	5.579
ENERGY IMPORT DEPENDANCE %	28.30	30.33	34.47	35.30

Source: SORS Statistical office of the Republic of Serbia

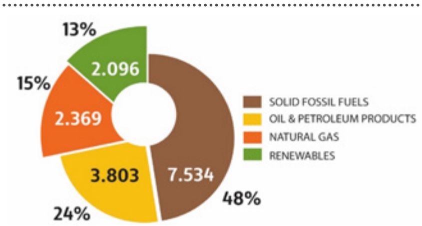
The average energy import dependency ratio for Serbia is in the range of 30-35% (average EU 28 – 53%). For 2018, energy import dependence equalled to 35.30% (coal 10.13%, oil and oil products 76.70%, natural gas 82%). Serbia's energy import expenses for 2018 were around 2 Bill.€.

Table 5.200 **Serbia - Primary Energy Consumption by Fuel (Mtoe)**

Primary Energy Consumption	2015	2016	2017	2018
GROSS INLAND CONSUMPTION-TPES	15.054	15.668	16.023	15.802
SOLID FOSSIL FUELS	7.744	7.889	7.874	7.534
OIL & PETROLEUM PRODUCTS	3.455	3.781	3.792	3.803
NATURAL GAS	1.945	2.101	2.352	2.369
RENEWABLES	1.910	1.897	2.005	2.096

Source: SORS Statistical office of the Republic of Serbia

Figure 5.244 **Serbia – Primary Energy Consumption by Fuel 2018 (Mtoe)**



Source: SORS

Primary energy consumption of the Republic of Serbia in 2018 was 15.802 million toe, while its structure is presented in Table 5.202. Over

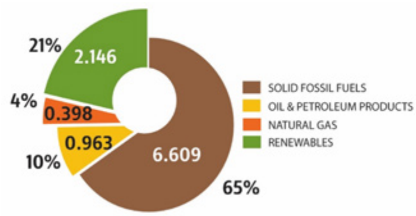
90% of the necessary coal amounts, whose share in the primary energy consumption is 48%, are secured from domestic sources. Coal consumption is dominantly connected with energy generation (about 86%), where thermal power plants have the highest share.

Table 5.201 **Serbia - Primary Energy Production by Fuel (Mtoe)**

Primary Energy Production	**2015**	**2016**	**2017**	**2018**
PRIMARY ENERGY PRODUCTION	10.862	10.791	10.577	10.116
SOLID FOSSIL FUELS	7.200	7.201	7.216	6.609
OIL & PETROLEUM PRODUCTS	1.113	1.018	0.977	0.963
NATURAL GAS	0.506	0.463	0.433	0.398
RENEWABLES	2.043	2.109	1.951	2.146

Source: SORS Statistical office of the Republic of Serbia

Figure 5.245 **Serbia – Primary Energy Production by Fuel 2018 (Mtoe)**



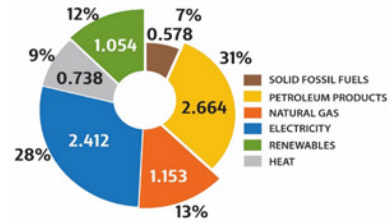
Source: SORS

A race is underway among coal, natural gas and renewables to provide power and heat to Serbia's fast-growing economy. Coal share decreases, natural gas consumption increases and renewables have a greater share in the energy mix than before.Considering the depleted natural gas and crude oil deposits in Serbia, the trend of increased import dependence continues. In 2018 import dependency has already reached 77% for oil and 82% for natural gas.

Table 5.202 **Final energy consumption by Fuel (Mtoe)**

Final Energy Consumption	**2015**	**2016**	**2017**	**2018**
FINAL ENERGY CONSUMPTION	8.045	8.370	8.496	8.599
SOLID FOSSIL FUELS	0.582	0.722	0.574	0.578
PETROLEUM PRODUCTS	2.541	2.623	2.652	2.664
NATURAL GAS	0.827	0.878	1.048	1.153
ELECTRICITY	2.338	2.373	2.418	2.412
HEAT	0.716	0.730	0.751	0.738
RENEWABLES	1.041	1.044	1.053	1.054

Figure 5.246 **Serbia – Final energy consumption by Fuel 2018 (Mtoe)**



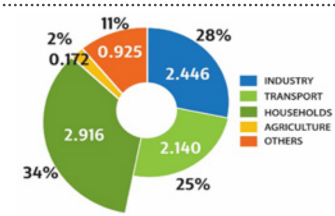
Source: SORS

Table 5.203 **Final energy consumption by Sector (Mtoe)**

Final Energy - Mtoe	**2015**	**2016**	**2017**	**2018**
FINAL ENERGY CONSUMPTION	8.045	8.370	8.496	8.599
INDUSTRY	2.088	2.212	2.316	2.446
TRANSPORT	1.987	2.029	2.112	2.140
HOUSEHOLDS	2.895	2.996	2.903	2.916
AGRICULTURE	0.156	0.195	0.193	0.172
OTHERS	0.919	0.938	0.972	0.925

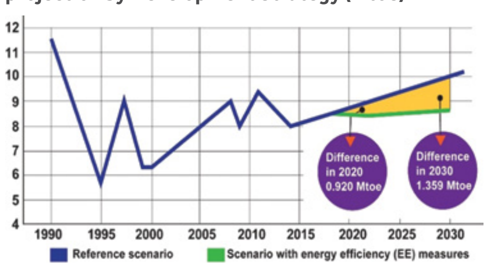
Source: SORS Statistical office of the Republic of Serbia

Figure 5.247 **Serbia – Final energy consumption by Sector 2018 (Mtoe)**



Source: SORS

Figure 5.248 **Serbia – Final energy consumption projection by Development Strategy (Mtoe)**



Source: Energy Sector Development Strategy of Republic of Serbia

Energy Resources and Potentials of the Republic of Serbia

The most significant domestic fuel source at present is coal with sufficient stocks to last even after 2050, according to the projected consumption levels. Table 5.204 shows Serbia's geological fossil fuel reserves.

Table 5.204 **Serbia - Geological reserves and resources of fossil fuel (Mtoe)**

Resources (Mtoe)	Proved and probable geological reserves	Total geological reserves and resources
HARD COAL	2.77	4.02
BROWN COAL	37.7	45.17
BROWN-LIGNITE COAL	134.25	193
LIGNITE	1.583(780*)	3.698
OIL	10.14	50
NATURAL GAS	3.37	50
OIL SHALE	-	398**

*Without Kosovo and Metohija
**Kerogen - organic part of oil shale
Source: Updated data from Energy Sector Development Strategy of Republic of Serbia for the period by 2025

The total renewable energy sources potentia which is technically available in the Republic of Serbia, is estimated to 5,65 Mtoe. 1,121 Mtoe of biomass and 0,979 Mtoe of hydropower of this potential is already utilized.

Biomass potential is available in the entire territory of the Republic of Serbia. Wood biomass is mostly located in the area of central Serbia, and agricultural biomass in the area of Vojvodina. The level of wood biomass use is relatively high (70%) while agricultural biomass is used very little (about 2%).

Table 5.205 **Serbia - Overview of technically usable RES potential - 2018 (Mtoe/per year)**

RES type (Mtoe/per year)	Technical potential in use	Unused technical potential	Total available technical potential
BIOMASS	**1.121**	**2.327**	**3.448**
Agricultural biomass	0.033	1.637	1.670
Parts of agricultural species	0.033	0.990	1.023
Parts in fruit growing wine growing and fruit processing	-	0.605	0.605
Liquid Manure	-	0.042	0.042
Wood (forest) biomass	1.086	0.444	1.530
Energy crops	-	-	not available
Biodegradable waste	0.002	0.246	0.248
HYDRO ENERGY	**0.979**	**0.700**	**1.679**
For installed capacities up to 10MW	0.014	0.141	0.155
For installed capacities from 10MW to 30MW	0.049	0.073	0.122
For installed capacities over 30MW	0.916	0.486	1.402
WIND ENERGY	**0.012**	**0.091**	**0.103**
SOLAR ENERGY	**0.001**	**0.239**	**0.240**
For the electricity generation	0.001	0.045	0.046
For the production of heat energy	≈0	0.194	0.194
GEOTHERMAL	**0.005**	**0.175**	**0.180**
For the electricity generation	≈0	≈0	≈0
For the production of heat energy	0.005	0.175	0.180
TOTAL from all RES	**2,118**	**3,532**	**5,650**

Source: Updated data from Energy Sector Development Strategy of Republic of Serbia for the period by 2025

Energy Market

Oil and Petroleum products

Ever since 2009, NIS has been the only company in the Republic of Serbia engaged in crude oil and natural gas research, exploration and production. Oil production in the Republic of Serbia is carried out in 63 oil fields with 666 wells by various extraction methods.Oil processing is performed in two oil refineries in Pancevo (4.8 million t/year) and Novi Sad (2.6 million t/year) producing a wide range of petroleum products. The plant in Novi Sad is not used at present and, so the current processing capacity is 4.8 million tones of crude oil a year.

Table 5.206 **Serbia - Oil and Oil products - Primary Energy Consumption (Mtoe)**

Primary Energy - Mtoe	2015	2016	2017	2018
GROSS INLAND CONSUMPTION	3.455	3.781	3.791	3.803
PRIMARY ENERGY PRODUCTION	1.113	1.018	0.977	0.963
IMPORT	3.012	3.510	3.745	3.859
STOCK CHANGES & BUNKERS	0.107	0.001	-0.064	-0.077
EXPORT	0.777	0.748	0.867	0.942
NET IMPORTS	2.235	2.762	2.878	2.917
ENERGY IMPORT DEPENDENCE %	64.69	73,05	75.92	76.70
OIL & PETROL PRODUCTS IN TPES %	22.95	24.13	23.66	24.00

SourSource: SORS - Statistical Office of the Republic of Serbia

Table 5.207 **Serbia - Oil and Oil products – Final Energy Consumption (Mtoe)**

Final Energy - Mtoe	2015	2016	2017	2018
GFINAL ENERGY CONSUMPTION	2.704	2.623	2.652	2.664
INDUSTRY	0.322	0.355	0.330	0.353
TRANSPORT	2.210	1.993	2.074	2.097
HOUSEHOLDS	0.031	0.065	0.048	0.038
AGRICULTURE	0.043	0.136	0.134	0.112
OTHERS	0.098	0.074	0.066	0.064
PETROL PRODUCTS N FEC %	31.58	31.34	31.21	30.98

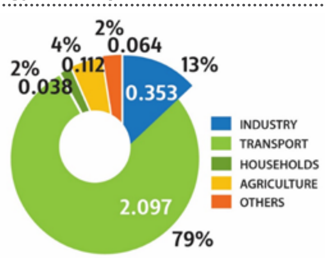
Source: SORS - Statistical Office of the Republic of Serbia

In 2018, Serbia's crude oil production was 0.926 million tons, while imports of crude oil and oil derivatives were around 2.69 mil. tons. The total consumption of crude oil and semi-finished products from domestic production, imports and supplies in 2018 in Serbia was about 3.6 mil. tons and the overall final consumption of petroleum products was 2.66 Mtoe. With regard to motor fuels, unleaded super gasoline accounted for 17.9%, gas oils-euro diesel for 74.3%, and LPG for 7.8%. In the Republic of Serbia, there are about 2.5 million registered vehicles, of which only 200 are electric vehicles, so it can be said that they do not affect the total consumption of motor fuels so far.

Crude oil imports are fully liberalized and the prices are set by the market. The import and trade of crude oil and petroleum products, including biofuels and compressed natural gas and storage, is undertaken by a large number of economic entities.

At the end of 2019 there were 25 licenses issued for crude oil trading and petroleum products storage, 52 for wholesale of crude oil and petroleum products and 461 for petroleum products retail trade. The retail trade of petroleum products in the territory of the Republic of Serbia is performed through a well developed and extensive trade network of about 1500 retail facilities.

Figure 5.249 **Serbia – Oil and Petroleum products final energy consumption 2018 (Mtoe)**



Source: SORS

PE Transnafta is the public company established by the government of the Republic of Serbia in 2005 for the purpose of carrying out pipeline transportation of crude oil and oil derivatives.

The company is also licensed for trade and storage of petroleum derivatives.

Crude oil transport to Pancevo Refinery is operated via Janaf, through the former Yugoslav oil pipeline infrastructure of 622 km from Adriatic Sea to Pancevo. Transnafta performs the oil transport through Serbian territory via a pipeline of 155 km stretching from the Danube on the border with Croatia to Pancevo. Associated pipeline infrastructure consists of a terminal in Novi Sad with four crude oil tanks of 10.000 m³ each. The average annual amount of transported oil is about 2.5 million tons/year (domestic and imported oil).

The transportation of oil derivatives in the Republic of Serbia is carried out by rail, ships and roads. Oil transport by oil pipelines and oil derivatives transport via product lines, are regulated activities of general interest separate from other energy-related activities and are performed by Transnafta under regulated prices. Pipeline transportation is a more economical, efficient and environmentally friendly mode of transport.

There are plans for a project for the construction of the Product Pipeline System connecting the Oil Refinery in Pancevo with the existing storage tanks in Smederevo and Novi Sad. The first section to Smederevo (27 km, with crossing the Danube) was scheduled to be put in operation in late 2020. Project realization after 2020 depends on the fuels' consumption trend and market demands.

A long-term plan for Serbian Product Pipeline System envisages connection of Pancevo to Sombor, in the north, and with the City of Nis, in the south with a total length of 402 km. Crude oil and petroleum products storage has a significant role in ensuring security in the country's energy supply, especially in case of market disruption caused by shortages usually followed by energy prices increase.

By EU Directive 2009/119/EC member states are obliged to maintain emergency stocks of crude oil and petroleum products in quantity of 90 days of average daily net imports or 61 days of average daily inland consumption. Signing the Agreement on the Energy Community of South-East Europe and gaining the EU membership candidate status, and in accordance with the above Directive, the Republic of Serbia is obliged to maintain conditions for keeping the required amount of crude oil and petroleum products that amounted to 1 million tons in 2020.

According to a statement from the Ministry of Mining and Energy, Serbia currently maintains reserves for 18 days of supply (2018).

Map 5.64 **JANAF oil pipeline route through Serbia and Croatia**

Source: Updated data from Energy Sector Development Strategy of Republic of Serbia for the period by 2025

NIS JSC is the dominant market player in Serbia dealing in oil, oil derivatives and natural gas exploration, production, processing and sales. Vertically integrated, it has been in the stock exchange since 2010. It is controlled by the Russian company "Gasprom Njeft" with a share slightly higher than 56%, by the Republic of Serbia with slightly less than 30%, while around 14% is owned by a great number of small shareholders through the Exchange.

The majority of NIS oil fields are located in Serbian territory, in the province of Vojvodina. However, it has business operations both in Serbia and abroad. In 2011, NIS started to expand its business to south-east Europe: Bosnia and Herzegovina, Romania and Hungary.

The company owns and operates oil refineries in Pancevo (annual capacity 4.8 million tons of crude oil) and Novi Sad (annual capacity 2.6 million tons of crude oil), and a natural gas refinery in Elemir. NIS refining complex produces an entire range of petroleum products - from motor gasoline and diesel fuel to mechanical lube oils and feedstock for the petrochemical industry, heavy fuel oil, road and industrial bitumen, etc. NIS accounts for 80% of the Serbian refined products market. The company sells a total of some 2.5 million tons of refined products annually.

In the retail market of motor fuels and other types of fuels, a considerable share is also held by Lukoil, OMV, MOL Serbia, EKO-Serbia, Knez Petrol, Petrol and smaller independent retail operators such as Europetrol, System Mihajlović, Art Petrol, AVIA, etc.Key development projects for NIS in the period 2018 - 2020 were the completion of the „Bottom-of-the-barrel" project at the Pančevo Refinery and the construction of a combined-cycle power plant, also in the town of Pančevo (140MW).

Directive 2009/28/EC, which refers to the required content of biofuels in motor fuels, in order to reduce greenhouse gas emissions, has not yet been implemented in domestic legislation. According to the Renewable Energy Action Plan it is assumed that this obligation would reach 10% of the share of biofuels in motor fuels by 2020, but the share of biofuels in the overall oil products market in 2016 was still negligible. Only one energy company, Biogor Oil doo from Sukova, has been licensed for the activity of biofuel production and bio-liquid production. The same company, with NIS, is only licensed for the energy activity of blending biofuels with fuels of petroleum origin.

Natural Gas

Natural gas is the third most used primary energy source in Serbia, after coal and oil. Gross domestic consumption in 2018 amounted to 2,667 bcm. Domestic production covered 18% of gas demand while the remaining amounts were secured by imports from the Russian Federation under a long-term contract.

At present Serbia has only two interconnections, the one at the border between Hungary and Serbia (entry point) and the other at the border of Serbia and Bosnia and Herzegovina (exit point). Serbia's total geological reserves of natural gas are small and can be estimated at 50 Mtoe.

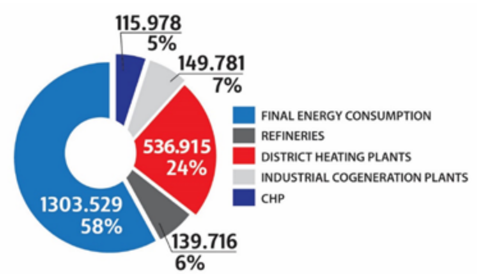
Natural gas exploration and production in Serbia is performed exclusively by the Petroleum Industry of Serbia (NIS). The transmission and transmission system operation are performed by natural gas transmission system operators: Srbijagas-Transportgas and Yugorosgaz-Transport. The length of the Srbijagas-Transportgas transmission system amounted to 2,339 km (95%) in north and central Serbia, while the length of the Yugorosgaz-Transport transmission system is 125 km (5%) in southern Serbia. Natural gas markets in Serbia are still under development.

Table 5.208 **Serbia - Natural Gas – balance and final energy consumption (bcm)**

NATURAL GAS - bcm	2015/ bcm	2016 /bcm	2017 /bcm	2018/ bcm
PRIMARY PRODUCTION	572.502	523.229	489.085	449.567
IMPORT	1,740.221	1,795.226	2,182.632	2,198.330
STOCK CHANGES	-114.511	56.850	-12.807	29.458
GROSS INLAND CONSUMPTION	2,198.212	2,375.305	2,658.910	2,677.355
TRANSFORMATION INPUT	885.174	886.884	935.973	942.390
CHP	20.064	46.582	94.992	115.978
INDUSTRIAL COGENERATION PLANTS	164.998	144.646	149.161	149.781
DISTRICT HEATING PLANTS	563.451	566.640	568.592	536.915
REFINERIES	136.661	129.016	123.228	139.716
CONSUMPTION IN THE ENERGY SECTOR	209.707	180.986	202.969	197.345
LOSSES	11.433	22.544	36.105	36.705
ENERGY AVAILABLE FOR FINAL CONSUMPTION	1,091.898	1,284.891	1,483.863	1,500.915
FINAL NON-ENERGY CONSUMPTION	157.658	292.077	299.305	197.386
FINAL ENERGY CONSUMPTION	934.240	992.814	1,184.558	1,303.529
INDUSTRY	546.388	550.089	680.631	772.581
TRANSPORT	6.931	6.502	6.832	13.329
HOUSEHOLDS	189.822	210.678	240.011	243.982
AGRICULTURE	20.713	28.953	22.564	23.506
OTHER USERS	170.386	196.592	234.520	250.131
NATURAL GAS IMPORT DEPENDANCE %	79	76	82	82

Source: SORS - Statistical Office of the Republic of Serbia

Figure 5.250 **Serbia – Natural gas transformation and consumption structure - 2018 (mcm, %)**



Source: SORS

Natural gas imports from the Russian Federation under long-term and other contracts amounted to 2,198 bcm in 2018, and all imported quantities were delivered at the Serbian – Hungarian border.

Serbia is intensively working on interconnections with neighbouring countries, which will enable gas supplies from new sources. The interconnection with Bulgaria is crucial through the construction of the Nis-Dimitrovgrad-Sofia gas pipeline.

The Bulgaria-Serbia Interconnection (IBS), expected to be completed by the mid 2022 at the latest, along with the Greece-Bulgaria Interconnection (IGB), connecting Serbia to the Southern Gas Corridor and opening up opportunities for the future supply of Caspian gas via the TANAP and TAP pipelines, as well as the regional LNG terminals. In addition to the TANAP and TAP pipelines, whose capacity is limited and already "sold out", the Turkish Stream is a realistically promising option. Under the Gastrans management, Serbia has built a 403 m long line section of the main interconnector gas pipeline from the border with Bulgaria (Zajecar) to the border with Hungary (Horgos), which is a continuation of the TurkStream pipeline.

The Balkan Stream project is of strategic importance for Serbia and provides the backbone of many new energy projects. The construction work is finished on both sides of the border. The earliest date for completion and commissioning would seem to be in the first half of 2021. This represents a new supply and transit route (with capacity of 12,87 bcm/y) of Russian gas primarily, thus increasing Serbia's energy security and will enable further reindustrialization of the country. Furthermore, there are plans for new interconnections between Serbia and Romania (Mokrin – Arad) and between Serbia and Croatia (Futog-Sotin).

Table 5.209 **Serbia - Technical characteristics of the natural gas transmission system – 2018**

Transmission system characteristics	Srbijagas	Yugorosgaz
Capacity	= 18 mil m³/day	= 2.2 mil m³/day
Pressure	16-75 bar	16-55 bar
Length	2339 km	125 km
Diameter	DN 150 - DN 750	DN 168 - DN530
Number of entries	13	1
Number of exits	248	5
Interconnector to B&H	1	/
Natural gas storage	1	/

Source: Serbiagas

Transmission and Storage

Under the agreement of the governments of Romania, Bulgaria, Greece and Serbia, the concept of the Balkan Gas Hub provides for the supply of natural gas from different sources: the Black Sea (Romania and Bulgaria), the Southern Gas Corridor (Caspian region, Middle East and Eastern Mediterranean), LNG terminals in Greece and Turkey and Russian gas via Turkish stream. The shortest route to the Central European gas market is passing through Serbia. Therefore, Serbia has a key role to play in ensuring the transit of natural gas to Central Europe after its entry into the Balkan Gas Hub.

The Bulgaria (Sofia)–Serbia (Nis) Interconnector is one of the priority projects between the two countries. Initially, the interconnector pipeline is expected to deliver 1,8 bcm of natural gas annually. The Nis-Sofia interconnector has a length of 171 km and is planned to be operational in mid-2022. The European Union, through its grants, is contributing to the financing of the project, and 49.6 mill. € has been committed by Serbia. The overall development of the Nis-Sofia transport system, which will provide the full capacity of reverse transmission of natural gas (2,7 bcm from Serbia to Bulgaria and 3,2 bcm from Bulgaria to Serbia), requires additional 208 mill. €.

In June 2017, a Road Map was signed between the Ministry of Mining and Energy and Gazprom for the implementation of the project Balkan Stream, for the construction of the main transport gas pipeline in the territory of the Republic of Serbia, from the border with the Republic of Bulgaria (Zajecar) to the border with Hungary (Horgos).

A joint project company, Gastrans LLC Novi Sad is the project developer and 95% of activity has already been done in Serbia. The "Balkan Stream" gas pipeline in Serbia is just over 400 kilometres long, the projected pressure is 75 bar, the pipe diameter is 1,220 millimetres and annual gas transportation capacity is 12,87 bcm. This pipeline is planned to be operational in the first half of 2021. Implementation of the Bulgaria-Serbia-Hungary main gas pipeline project will significantly increase the level of energy security both in Serbia and the region. On 21 February 2020, the Serbian Energy Agency Council adopted a Decision issuing a certificate to Gastrans LLC as an independent natural gas transmission operator.

Srbijagas-Transportgas is creating preconditions for the connection to neighbouring countries network. In addition to the Nis-Sofia interconnector there are plans to build interconnections with Romania (Mokrin-Arad - 1 bcm) and Croatia (Futog – Sotin -1,5 bcm). Banatski Dvor Underground Gas Storage (UGS) is located at a depleted gas deposit whose capacity used to be 3,3 billion cubic meters of natural gas. There is currently 450 million cubic meters of available capacity while the maximum productivity in the withdrawal process amounts to 5 million m³/day. After phase two of construction, the storage will have increased to 800 million cubic meters of capacity. This storage is connected to the natural gas system through two gas pipelines.

During 2018, more natural gas was taken out of the storage than delivered to the facility. At the beginning of 2018, there was 404 million m³ of commercial gas. From the transportation system, 273 million m³ were delivered to the storage, of which 3 million m³ was consumed by the facility's own needs, while the remaining

270 million m³ of gas was injected for commercial purposes. Users have taken over 299 million m³ from the storage, also delivered to the transport system. At the end of 2018, there was 375 million m³ of commercial gas inside the storage. There are plans to build a new underground facility at Banatski Itebej, with a capacity similar to the existing Banatski Dvor as well as a smaller Tilva storage. Srbijagas and Yugorosgaz have undergone the initial unbundling of transmission activities. The two newly established transmission system operators are the Transportgas Serbia LLC and Yugorosgaz -Transport LLC companies.

Map 5.65 **Serbia – Current natural gas transmission network - 2019**

Source: Gastrans

Natural Gas Market

Natural gas market participants include producers (NIS JSC), suppliers (66 companies), public suppliers (33 companies), transmission system operators Srbijagas-Transportgas and Yugorosgaz-Transport, distribution system operators (33 active companies) and one storage operator UGS Banatski Dvor. Serbia currently consumes about two and a half billion cubic meters of gas annually. Industrial production is beginning to grow and Serbia will certainly need more gas. In the past five years, Serbia's natural gas consumption increased by about 5% per year, while the domestic production has fallen significantly. In the upcoming period, it is expected that the domestic production will continue to decline.

Given the increase in industrial consumption, the planned construction of several CHP installations and expanding the country's natural gas transportation and distribution network, it is estimated that annual consumption in 2030 will be about 4 bcm/y.

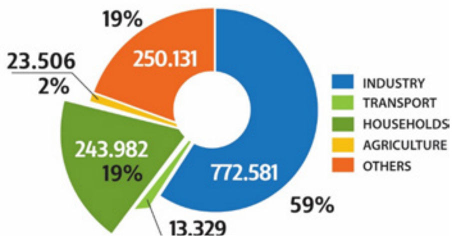
Under the Energy Law, the following regulated energy activities are of general interest:

- natural gas transmission and natural gas transmission system management,
- natural gas storage and natural gas storage facility management,
- natural gas distribution and natural gas distribution system management and
- public supply of natural gas.

Serbia's Energy Agency (AERS) is the competent body regulating the natural gas price for public supply, determining the natural gas transmission and distribution system access price and the natural gas storage access price. In order to ensure supply security of end customers, it is stipulated that households and small customers whose facilities are connected to the natural gas distribution system are entitled to public supply at regulated prices, if they opt not to choose another supplier. Small natural gas consumers are the final customers whose annual consumption of natural gas is less than 100,000 m³.

The government of Serbia appointed Srbijagas as the supplier of public natural gas suppliers under public tendering. The total distribution network length at the end of 2018 was 18.422 km. The share of the Srbijagas distribution network in total distribution network length is 52%. At the end of 2018, there were over 276.581 delivery points of which 64 inside the transport and 276.517 inside the distribution network. Of these, 262.814 or 95% are households, which is only roughly 10% of all households in Serbia. Average annual consumption of natural gas per connected household in 2018 was 1009 m³.

Figure 5.251 **Serbia - Final natural gas consumption (1,303.529 bcm) by sector - 2018 (mcm, %)**



Source: SORS

A bilateral market is functioning in the natural gas sector. In the wholesale natural gas market, buying and selling takes place directly between market participants. The wholesale natural gas market in 2018 was based on trade between natural gas suppliers and between natural gas suppliers and producers. In 2018, three suppliers (Srbijagas, King gas and Cestor Veks) and one producer, NIS, participated in the wholesale market. The average wholesale price at which suppliers sold natural gas to other suppliers in 2018 was 34.03 RSD/m³ (~0.29 €/m³).

At the end of 2018, the business of distribution and distribution system operation was performed by 32 licensed distribution system operators. In addition to distribution system operators, Srbijagas and Yugorosgaz, distribution and distribution system operation is performed by 30 other companies, most of which are owned by municipalities and cities, some are mixed and partly privately owned. The average weighted approved distribution system access price for all distribution networks in Serbia as of 31 December 2018 was 4.35 RSD/m³. In the retail bilateral market supply was carried out at both unregulated and regulated prices. Since 2018 all customers, except households and small customers, had to buy natural gas in the free market. The Serbian government appointed Srbijagas as a supplier supplying public suppliers with natural gas under the same conditions and price. During 2018, a total of 1.881 million m3 was delivered to buyers in the free market, while 321 million m³ was delivered to buyers under regulated prices.

The average weighted retail price realized in the free market in 2018, including transportation and distribution system use costs, was 35.26 RSD/m³ (~0,30 €/m³), while the realized weighted average retail price in the regulated market was 34.82 RSD/m³ (~0,29 €/m³).

The greatest share of natural gas, over 1.778 million m³ (81%) of the total amount was sold to final customers by Srbijagas in 2018. The second greatest share was sold by the DP Novi Sad Gas with 72 million m³, or about 3,3%, while Yugorosgaz came third with 51 million m³ or 2,4% of the total amount sold in 2018. Individual share of the remaining suppliers in the total amount is some 2%.The 2025-2030 Energy Sector Development Strategy considers two natural gas consumption scenarios: reference scenario and energy efficiency measures implementation scenario. Both scenarios foresee an increase of gas consumption, both for transformation input (CHP gas facilities, increase of gas share in district heating plants and auto producers) and for final consumption. Around 5 million, or 70% of Serbia's population, lives in areas with a developed transportation network, with further natural gas system expansion and consumption growth potential. In the upcoming period, natural gas consumption will be governed by various energy sector factors (natural gas price, infrastructure development, prices of other energy sources, etc.), general economic and social development factors (GDP growth, purchasing power of the population, implementation of environmental regulations, demographic indicators, structure of industrial production, etc.). Further increase of import dependency for natural gas can be expected, from 82% in 2018 to around 90% by 2025.

Solid Fossil Fuels - Coal

Coal represents the largest share in Serbia's Total Primary Energy Supply (TPES) (with a share of 48%) followed by Oil (24%), Natural gas (15%) and Renewables (13%). Coal is the most significant domestic fuel, and the estimates suggest that existing deposits should be sufficient even after 2050. The coal sector includes coal extraction and processing. Coal is mined in surface and underground mines and in one underwater mine. However, the domestic coal structure is dominated by low-quality lignite.

Table 5.210 **Serbia - Solid Fossil Fuels - Coal - Primary Energy Consumption (Mtoe)**

Solid Fossil Fuels - Mtoe	2015	2016	2017	2018
GROSS INLAND CONSUMPTION	7.744	7.889	7.874	7.534
PRIMARY ENERGY PRODUCTION	7.200	7.201	7.216	6.609
IMPORT	0.629	0.638	0.686	0.780
EXPORT	0.007	0.015	0.017	0.016
STOCK CHANGES	-0.079	0.064	-0.011	0.162
NET IMPORT	0.623	0.624	0.669	0.763
ENERGY IMPORT DEPENDANCE %	8.04	7.91	8.49	10.13
COAL IN TPES %	51.44	50.35	49.14	47.68

Source: SORS - Statistical Office of the Republic of Serbia

Table 5.211 **Serbia - Solid Fuels - Coal - Energy Balance (Mtoe)**

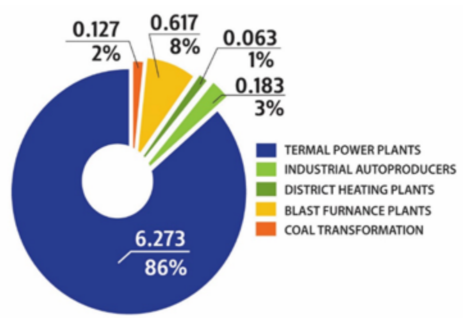
Solid Fossil Fuels Energy Balance	2015	2016	2017	2018
GROSS INLAND CONSUMPTION	7.744	7.889	7.874	7.534
TRANSFORMATION				
INPUT	7.277	7.345	7.513	7.263
THERMAL POWER PLANTS	6.688	6.622	6.712	6.273
INDUSTRIAL AUTOPRODUCERS	0.068	0.068	0.074	0.183
DISTRICT HEATING PLANTS	0.065	0.066	0.058	0.063
BLAST FURNANCE PLANTS	0.346	0.449	0.509	0.617
COAL TRANSFORMATION	0.110	0.139	0.160	0.127
TRANSFORMATION OUTPUT	-0.140	-0.184	-0.216	-0.473
ENERGY SECTOR OWN USES & LOSSES	0.001	0.001	0.000	0.161
AVAILABLE FOR FINAL CONSUMPTION	0.606	0.727	0.577	0.583
NON-ENERGY CONSUMPTION	0.024	0.005	0.003	0.005
FINAL ENERGY CONSUMPTION	0.582	0.722	0.574	0.578
INDUSTRY	0.279	0.351	0.261	0.291
TRANSPORT	0.000	0.000	0.000	0.001
HOUSEHOLDS	0.208	0.269	0.257	0.241
AGRICULTURE	0.000	0.000	0.000	0.000
OTHERS	0.095	0.102	0.056	0.045
SOLID FOSSIL FUELS N FEC %	7.23	8.63	6.75	6.72

Source: SORS - Statistical Office of the Republic of Serbia

In 2018, 7.263 Mtoe (38,645 million tons) were consumed in transformation processes, of which 6.273 Mtoe (36,517 million tons) or 86% in thermal power plants, while the remaining 14% by industrial power plants, district heating plants, blast furnaces and coal processing.

Almost 98% of the total domestic coal production comes from surface mining (37 million tons in 2018) while the remaining amount of 0,660 Mt comes from underground and underwater coal mines. Since the domestic production mainly yields low-quality lignite and covering some 95% of the total coal demand, roughly 5 - 10% are imported. Coal imports include different types of coal, primarily coke for metallurgy and high-caloric coal for industrial use, followed by anthracite and brown coal for retail consumers.

Figure 5.252 **Serbia - Coal consumption in transformation processes - 2018 - 7263 Mtoe**



Source: SORS

Table 5.212 **Serbia - Coal import structure in 2018 (t)**

Structure of coal import in (t)	
Coke	774455
Coal Tar	4
Patent Fuel	0
BKB-PB	2288
Anthracite	25102
Other bituminous coal	235166
Sub-bituminous brown coal	368973
Total	1405988

Source: SORS - Statistical Office of the Republic of Serbia

Coal mining and processing in Serbia takes place in:

- Surface coal mining in two major mines in Kolubara and Kostolac operated by PE EPS. Production of low-quality lignite in 2018 was: Kolubara 28,4 Mt and Kostolac 8,6 Mt

- Underground mining in PE Resavica – nine underground mining facilities producing high quality hard and brown coal with annual production of about 0,48 Mt.
- Underwater mining of lignite in Kovin with an average annual production of 0,22 Mt.

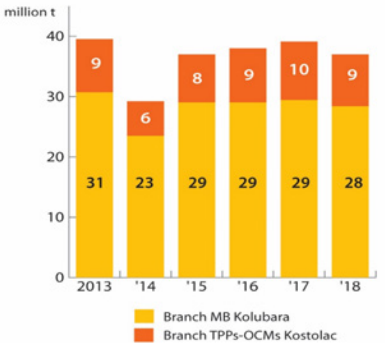
One of the problems in supplying coal from surface mines is the uniformity of coal quality in order to achieve savings, as well as to reduce specific coal consumption by the Nikola Tesla Thermal Power Plants (TENT). Kolubara coal processing plant also produces some 0,78 Mt of dry lignite.

Table 5.213 **Serbia - Coal Production structure by EPS subsidiaries in 2018 (t)**

Coal (t)	Kolubara	Kostolac	EPS - 2018
TPPs	27,211,080	8,425,112	35,636,192
Drying	779,188	/	779,188
Industry	175,047	179,101	354,148
Heating plants	208,308	/	208,308
TOTAL 2018	28,373,623	8,604,213	36,977,836

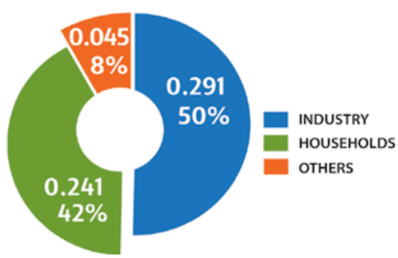
Source: EPS

Figure 5.253 **Serbia - Coal production by EPS subsidiaries 2013-2018 (Mt)**



Source: EPS

Figure 5.254 **Serbia - Coal – Final energy consumption by sector 2018 – 0.578 Mtoe**



Source: SORS

Final coal consumption in 2018 amounted to 0.583 Mtoe, of which 0.005 Mtoe and 0.578 Mtoe for non-energy and energy purposes, respectively. The share of industry in the final consumption mix is 59%. It is followed by households 19% and other sectors with 22%.

Map 5.66 **Serbia - Mining basins of Serbia**

Source: EPS

Serbia's most significant coal deposits consist of low-quality lignite. Geological reserves of lignite compared to the geological reserves of all coal types in Serbia cover 97%. Total coal reserves available for mining are substantial and represent a realistic basis for further long-term development of the energy sector in general and particularly for electricity generation.

Table 5.214 **Serbia - Coal geological reserves (Mtoe)**

Coal Reserves (Mtoe)	Proven and probable geological reserves	Total geological reserves and resources
Hard coal	2.77	4.02
Brown coal	37.7	45.17
Brown-lignite coal	134.25	193
Lignite	1.583 (780*)	3.698

*Without Kosovo and Metohija Source: EPS

Table 5.215 **Serbia - Coal geological reserves (10^3t)**

Coal Reserves (10^3t)	Serbia without APs	AP Kosovo and Metohija	AP Vojvodina	Total Serbia
Hard coal	8.215			8.215
Brown coal	111.294			111.294
Brown-lignite coal	536.678		8.729	545.407
Lignite	3.989.333	15.746.000	275.000	20.010.333

Source: EPS

The structure of Serbia's fossil fuels reserves is presented in Table 5.215. Reserves of higher quality energy products, such as oil and gas are negligible and make less than 1% of geological reserves with a high exploration level, while the remaining 99% of energy reserves include various types of coal, with lignite having the highest share, over 95% in the investigated reserves.

Table 5.216 **Serbia - Geological reserves and resources of fossil fuel (Mtoe)**

Resources (Mtoe)	Proven and probable geological reserves	Total geological reserves and resources
Hard coal	2.77	4.02
Brown coal	37.7	45.17
Brown-lignite coal	134.25	193
Lignite	1.583 (780*)	3.698
Oil	10.14	50
Natural gas	3.37	50
Oil shale	-	398**

*Without Kosovo and Metohija **Kerogen - organic part of oil shale Source: EPS

Estimated reserves of oil shale in the Republic of Serbia are about 4,8 billion tons. They may be found in few locations, but a higher degree of exploration has been achieved at the Aleksinac reservoir with the deposit of around 2 billion tons. There is some interest in oil shale mining.

However, its exploitation depends on the prevailing crude oil price. Oil shale can be effectively used to produce synthetic oil (by extraction), which can be used as fuel or upgraded by refining to petroleum products, while the residual part could be used in electricity generation. From an environmental point of view, the project is acceptable since there is no need for extracted oil shale disposal.

Strategic mid-term coal sector actions and measures include:

- More intensive exploration of coal deposits across the entire area of Republic of Serbia.
- Opening of replacement capacities for existing open pit mines close to depletion and opening of open pit mines to supply new thermal power plants.
- Optimization and concentration of underground coal production.
- Introduction of coal quality management system.
- Harmonization of national legal framework with EU and Energy Community legislation in the coal sector.

Electricity

The current structure of the electricity sector in Serbia was established in 2005 after the unbundling and internal reorganisation of the vertically integrated public company Electric Power Industry of Serbia (PE EPS). Transmission, transmission system operation and market operation are performed by EMS (TSO), while EPS is the company dominating the generation, distribution, supply, public supply and supply of the last resort. Both companies EMS and EPS are 100% owned by the Republic of Serbia. In 2016, EPS established EPS Distribution, a distribution system operator (DSO). Although the legal unbundling of EPS Distribution was finalized the functional unbundling has not yet been completed. In partnership with EPEX SPOT, France, EMS established an organised day-ahead electricity market (exchange) SEEPEX.

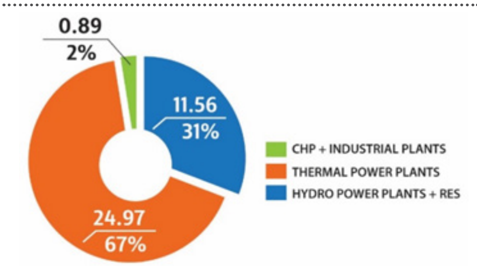
Table 5.217 **Serbia - Electricity balance & Final electricity consumption (TWh)**

Electricity - TWh	2015	2016	2017	2018
GROSS ELECTRICITY PRODUCTION	38.29	39.34	37.04	37.42
HYDRO POWER PLANTS + RES	10.79	11.56	9.81	11.56
THERMAL POWER PLANTS	27.13	27.19	26.41	24.97
CHP + INDUSTRIAL PLANTS	0.37	0.59	0.82	0.89
ENERGY SECTOR CONSUMPTION	5.02	5.01	4.94	4.96
IMPORT	6.30	5.07	6.55	6.40
EXPORT	7.22	6.99	5.72	6.28
GROSS ELECTRICITY CONSUMPTION	32.35	32.41	32.93	32.58
LOSSES IN TRANSMISSION	0.93	0.89	0.85	0.87
LOSSES IN DISTRIBUTION	4.24	3.92	3.96	3.66
FINAL CONSUMPTION	27.18	27.60	28.12	28.05
INDUSTRY	7.54	8.00	8.40	8.74
TRANSPORT	0.35	0.35	0.38	0.38
HOUSEHOLDS	14.06	13.94	13.81	13.41
AGRICULTURE	0.31	0.31	0.34	0.34
OTHER	4.92	5.00	5.19	5.18

Source: SORS, Statistical office of Republic of Serbia.

Conventional thermal power generation has the largest share (close to 70%) in the generation mix, followed by hydropower generation (some 30%). Serbia is almost self-sufficient, with minor seasonal deviations of shortages and surpluses.

Figure 5.255 **Serbia - Gross electricity generation in 2018 (TWh, %)**



Source: SORS

Total electricity generation in 2018 amounted to 37.42 TWh, while the gross electricity consumption was at the level of 32.58 TWh.

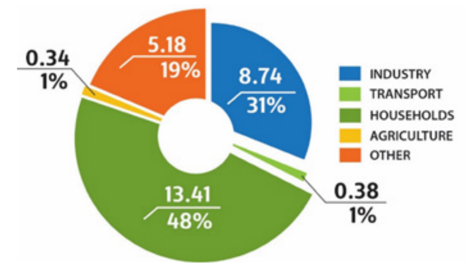
The largest share of generation was achieved by thermal power plants (67%) and hydropower plants plus other RES (31%). The small independent electricity producers generated some 0.6 TWh. Electricity imports and exports were 6.40 TWh and 6.28 TWh, respectively.

In addition to EPS, there are 66 licensed free-market suppliers with main activities in the area of cross-border trade, mainly for transit through Serbia, which is dominant due to the central geographic position of Serbia's electricity system with 8 borders. In the year 2018, electricity transit through Serbia reached the level of 12 TWh.

Electricity demand has shown little increase over the past several years. Annual peaks are still achieved in winter partly due to the cold climate and extensive use of electricity for heating. In recent years, there was a somewhat larger increase in the summer peak loads. Maximum average hourly load of the system amounted to 5,805 MW and it was achieved on 28 February 2018 at 8 p.m.

Figure 5.256 shows the structure of Serbia's final electricity consumption in 2018. The largest share was consumed by households (48%) and industry (31%). The remaining 19% of the final consumption was used by public and commercial users.

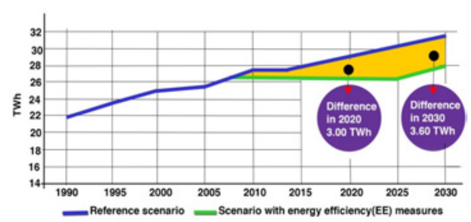
Figure 5.256 **Serbia - Final electricity consumption by sector 2018 (TWh, %)**



Source: SORS

In 2015, the Serbian government adopted the Draft Energy Sector Development Strategy covering the period up to 2025 with the forecasted annual average growth in electricity consumption until 2025 of less than 1%. These assumptions took into account the growth of the industrial sector as well as energy efficiency measures in all consumption sectors. Energy efficiency measures can save some 3TWh of the final consumed electricity in 2025 based on international benchmarks.

Figure 5.257 **Serbia - Final electricity consumption projections up to 2030 (TWh)**



Source: Energy Sector Development Strategy of the Republic Serbia 2025-2030

Generation Capacities

Serbia's electricity generation capacities comprise of thermal power plants (TPP), cogeneration power plants (CHP), large and small hydro power plants (HPP), industrial power plants and some independently owned plants using renewable energy sources (solar, wind, biomass and biogas).

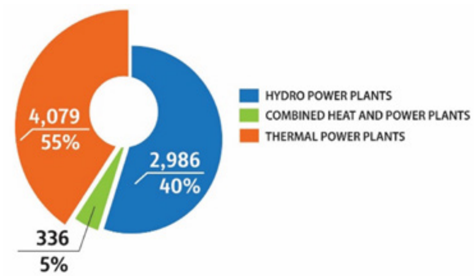
5

Table 5.218 **Serbia - EPS power plants – Net output capacity – 2018 (MW)**

Fossil Fuels	**MW**	**Hydro**	**MW**
TPP Nikola Tesla A	1,622	HPP Djerdap 1	1,113
TPP Nikola Tesla B	1,220	HPP Djerdap 2	270
TPP Kolubara	216	Vlasinske HPPs	129
TPP Morava	108	HPP Pirot	80
TPP Kostolac A	281	HPP Bajina Basta	420
TPP Kostolac B	632	PSHPP Bajina Basta	614
TPP total	4,079	HPP Zvornik	111
		HPP Elektromorava	18
CHP		HPP Potpec	51
CHP Novi Sad	208	HPP Bistrica and Kokin	
Brod	124		
CHP Zrenjanin	100	HPP Uvac	36
CHP Sremska Mitrovica	28	Mini HPPs	20
CHP total	**336**	**HPP total**	**2,986**
EPS POWER PLANTS TOTAL: 7,401 MW			

Source: EPS

Figure 5.258 **Serbia - EPS power plants – Net output capacity – 2018**



Source: EPS

Besides the main power plants owned by EPS there are more than 250 independent small RES power plants, connected to the distribution system:

Table 5.219 **Serbia - Independent privileged electricity producers – 2019 (MW)**

Privileged RES generation	**MW Active**	**MW On hold**
Independent mini HPPs	69.4	28.7
Independent Solar PP	8.8	/
Independent Wind PP	330.0	236.0
Independent Biogas PP	22.5	37.0
Independent Biomass PP	2.4	2.4
Landfill gas and sewage gas PP	/	3.1
Waste fired PP	/	30.2
Gas fired high efficiency CHP	21.9	14.0
TOTAL	455	351.4

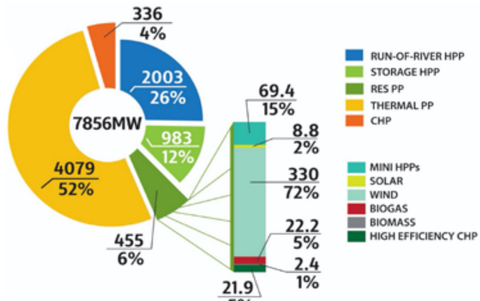
Source: MoME, EPS

Table 5.220 **Total installed generation capacities structure in 2019 (MW, %)**

Structure of generation	**MW**	**%**
RUN-OF-RIVER HPP	2003	26%
STORAGE HPP	983	12%
RES PP	455	6%
THERMAL PP	4079	52%
CHP	336	4%
TOTAL	7856	100%

Source: MoME, EPS

Figure 5.259 **Serbia - Total installed generation capacities structure in 2019 (MW, %)**

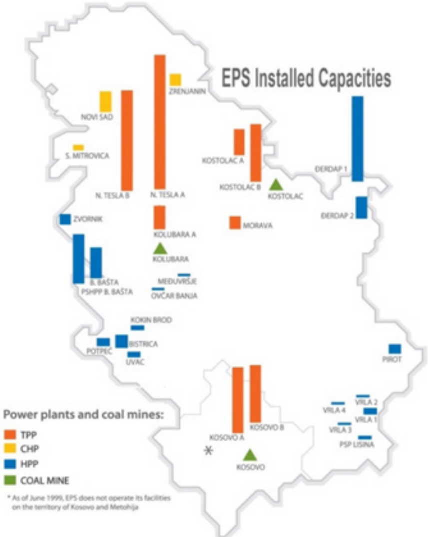


Source: MoME, EPS

Considering the age (over 25 years) and efficiency of existing generation capacities and the fact that some of them will be decommissioned, it is necessary to build new capacities. It is planned to build some coal-fired thermal power plants, a number of natural gas-fired CHPs, as well as to add several facilities fuelled by renewable energy sources (wind and hydro). Up to 2028 it is expected to add almost 1000 MW of wind capacity, mostly operated by independent power producers. Rehabilitation and revitalization of existing major power plants (TPP Nikola Tesla, HPPs Djerdap, Zvornik, Potpec etc.) will secure additional capacity for power generation. Other electricity generation projects preferably dedicated to utilising renewable energy sources are covered by the NREAP (National Renewable Energy Action Plan) adopted in 2013.

During the same period, 2020-2030, due to obligations stemming from the Energy Community Treaty, Serbia has to harmonize its electricity consumption and generation to meet the targets in energy efficiency, RES share in gross final consumption, limited pollutant emissions from large combustion plants and expected new climate targets. Under the Paris Climate Agreement, Serbia has committed to reduce its GHG emissions by 9.8% by 2030 compared to 1990 levels, however, it still does not have to reduce its GHG emissions under the Energy Community Treaty. Throughout the EU accession process, Serbia's electricity sector will face mandatory and financially challenging CO_2 emission costs by implementing the EU Emissions Trading Scheme. Currently, the share of electricity generation in Serbia's total CO_2 emissions is around 50%.

Map 5.67 **Serbia - EPS - Installed electricity generation capacities**



Source: EPS

In January 2020, the Serbian government adopted the National Plan for the Reduction of the Main Pollutant Emissions from Old Large Combustion Plants (NERP) with the aim of harmonizing emissions from large combustion plants with the limits set out in the EU Industrial Emission Directive by the end of December 2027. Application of the Large Combustion Plants Directive and Industrial Emission Directive requires significant investments into modernisation and environmental improvements. Under EPS estimates, the required amount is close to 1 billion €.

Table 5.221 **Serbia - Potential new build projects of the electricity sector**

Project name	Installed capacity	Approximate value in billion €
TPP TENT B3	750 MW	1,60
TPP Kolubara B	2 X 375 MW	1,50
CHP Novi Sad	450 MWe	0,40
Natural gas fired CHPs	860 MWe	1,50
HPP Velika Morava	147,7 MW	0,36
HPP Ibar	117 MW	0,30
HPP Zapadna Morava	66.45 MW	0,28
HPP Middle Drina	321 MW	0,82
PS HPP Bistrica	4 x 170 MW	0,56
PS HPP Djerdap 3	2 x 300 MW	0,40
Small HPP	387 MW	0,50

Source: MoME, EPS

Transmission Infrastructure

Serbia's transmission system, without Kosovo and Metohija (K&M) operated by EMS, comprises of 38 substations of 400/x, 220/x and 110/x kV with installed capacity of 15,706 MVA. There are 449 high voltage lines of 400, 220 and 110 kV with total length of 9453 km. EMS transmission system is connected with the neighbouring power systems via 22 interconnection overhead lines of 400, 220 and 110 kV.

Table 5.222 **Serbia - EMS transmission system in 2018 (without K&M)**

Transmission system elements	Number of lines	Length km
400 kV	36	1.766
220 kV	46	1.845
110 kV	367	5.842
Total	**449**	**9,453**

Source: EMS, 2019-2028 Transmission System Development Plan

The Transmission Network Code governing technical transmission aspects and relations between EMS and system users was adopted for the first time in 2008. During 2011, 2013 and 2017 there were a number of amendments aligning it with the Market Code. In 2016, PE EMS was corporatized and it functions as a closed joint stock company, EMS JSC.

In 2018, by applying the ruling charges, average transmission use-of-system charge amounted to 0.49 RSD/kWh (~4 €/MWh) which is one of the lowest charges in Europe. Electricity losses of Serbia's transmission system amounted to 868 GWh in 2018, which represents 2.13% of electricity withdrawn into the transmission system. The loss reduction trend continued.

In cooperation with neighbouring transmission system operators, EMS is responsible for the allocation of rights to use available cross-border transmission capacities on interconnection lines of the Serbian power system. The joint explicit auctions for 100% of capacity allocations are in use on the borders with Hungary (2011), Romania (2013) Bulgaria and Croatia (2014), Bosnia & Herzegovina (2015) and North Macedonia (2017) while on the borders with Albania and Montenegro, there are the 50:50% rights for both neighbouring operators. In 2018, EMS generated revenue from capacity allocation amounting to 25 mill. €. Transmission system operator - EMS, as an ENTSO-E member (European Network of Transmission System Operators for Electricity), is required each year to update the national Ten-Year Network Development Plan (TYNDP), aligned with the Pan-European TYNDP. EMS is already participating in activities aimed at strengthening the Trans Balkan and North Continental South East (CSE) Power Corridors.

A group of projects is dedicated in strengthening internal transmission capacities (by replacing obsolete 220 kV network) and reinforcing the transmission capacity of busy international corridors (North – South, North-East to South-West) up to 2028:

1. New interconnection transmission lines between Serbia and Romania (double 400 kV transmission lines) Resica (Romania) - Pancevo (Serbia) and Porțile de Fier - Djerdap 1.
2. New double 400 kV interconnection between Serbia, Montenegro and Bosnia and Herzegovina.
3. New 400 kV interconnection between Serbia and Croatia.
4. New 400 kV interconnection between Serbia and Bulgaria.
5. Upgrade of the West Serbia's network to a voltage level of 400 kV (400 kV transmission lines Kragujevac - Kraljevo and Obrenovac - Bajina Basta).

Distribution Infrastucture

In July 2015, as a continuation of restructuring and corporate reform the incumbent company – EPS, established EPS Distribution having as a main activity electricity distribution and distribution system operation (DSO). The legal unbundling of the EPS Distribution was finalized, however, functional unbundling has not been completed yet.

By the end of 2020, the DSO was obliged by Law to take over metering devices, switchboards, connection lines, installation and equipment in the switchboard and other devices within the connection in the facilities of existing customers or producers since these devices and equipment are part of the distribution system. Strategic goals in the field of electricity distribution are to increase supply reliability levels, reduce electricity losses and optimize distribution network use.

The primary target of distribution system operator is to improve the measurement system of Medium Voltage (MV) and Low Voltage (LV) customers, those with active and reactive energy and monthly maximum power. Smart grids and measurement systems will enable high reliability and quality levels of delivered electricity. They will stimulate better consumption management and a more dynamic electricity market, as well as considerable reduction of technical and commercial losses. There is expectation that 3 million meters will be replaced by 2030.

Distribution system (without Kosovo and Metohija) covers around 36,000 substations with the total installed capacity of around 30,000 MVA and more than 160,000 km of distribution lines, with voltage levels of 110, 35, 20, 10 and 0.4 kV. Distribution Network Code has been in force since early 2010. The new version was approved by the regulator, the Energy Agency of the Republic of Serbia in late 2017.

The total number of electricity metering points for customers in Serbia (without Kosovo and Metohija) in late 2018 was 3.651.169, while the total number of customers was 3.507.133.In 2018, the average distribution use-of system charge for all customers amounted to 2.95 RSD/kWh (~2.5 c€/kWh). Today, the average monthly consumption per household in Serbia is 345 kWh.

Electricity delivered to customers over the distribution system in 2018 was almost fully taken over from the transmission system, nonetheless, considering the growth of distributed generation (mostly RES connected to the distribution system), some 8 GWh of electricity was supplied from the distribution system to the transmission system.

The core distribution network problem are high losses primarily caused by unauthorised connections, theft and long-term network and metering devices underinvestment. Distribution losses amounted to 3.66 TWh, or 12.2% of the electricity supplied to the distribution system in 2018. Designated future electricity distribution projects include improving metering infrastructure, distribution network automation, obsolete SS 110/X kV reconstruction project, together with the new SS 110/X kV construction project. The total investment value of these four projects is around 277 mill €.

Electricity Market

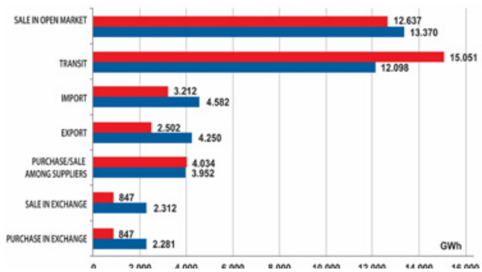
Electricity market in Serbia includes bilateral electricity market, balanced electricity market and organized electricity market. Main players are producers, wholesale and retail suppliers, customers, TSO and DSO, market operator and power exchange.

Purchase and sales of electricity are organized on the bilateral market directly between market players. On the wholesale bilateral market, the players traded electricity under open market prices, while on the retail sale side there are two groups of customers.

The first one includes customers supplied under open market prices (such as industrial customers), while the second one includes households and small customers supplied by the Public Supplier (EPS Supply) under regulated prices. After the Energy Law was adopted in December 2014, as of 1 January 2015 all households and small customers were able to freely choose their electricity supplier or remain a customer of the Public Supplier. EPS daughter company - EPS Supply - was appointed by the Energy Agency in 2013 as the official public supplier and a supplier of last resort. Coexistence of unregulated and regulated segments of the domestic electricity market operating under entirely different conditions is still a status quo in Serbia. However, it is only a matter of time when the low priced regulated electricity market (low retail prices for obvious socio-political reasons) will become open in the sense of most EU countries.

In 2018 there were 68 electricity market players entitled to nominate operational plans based on a relevant contract signed with EMS (mostly dealing with cross-border exchange), while there were only 18 supplying customers in the open market.

Figure 5.260 **Serbia - Electricity quantities by suppliers' activities in 2017 and 2018 (GWh)**



Sources: IEA, Eurostat, WB, SORS Statistical office RS, compiled by AERS

EPS was still the dominant supplier in the open market with 96,4% of the total electricity quantities sold to final customers in the open market and with 98,3% of the total final consumption.

Achieved average annual electricity price in 2018 for industrial customers was 7.55 RSD/kWh (~6.4 c€/kWh), while for households and small customers, this price was at the level of 6.84 RSD/kWh (~5.8 c€/kWh). On 31 October 2019, the Energy Agency (AERS) approved new power transmission tariffs, electricity distribution tariffs and guaranteed supply prices. The transmission tariff was increased by 3.9% and the distribution tariff was increased by 2%. Average power price for customers entitled to guaranteed supply at regulated prices (households and small customers) amounts to 7.3 RSD/kWh (~6.2 c€/kWh) – (taxes and duties excluded).

Even after this price modification, the price applied to households is still considerably lower than regional and EU prices. In order to maintain the balance between total production, consumption, electricity exchanges and deviations in 2018, EMS hired balance entities (such as EPS) to perform secondary and tertiary regulation within its regulatory area and also cross-border balancing. At the end of 2018, a total of 63 electricity market participants had a Balance Responsibility Agreement signed with a transmission system operator.

The total balance energy engaged in 2018 was 832 GWh, for which the total weighted settlement price was 47.83 €/MWh. On 14 July 2015, EMS established SEEPEX Belgrade - Electricity Exchange, in partnership with EPEX SPOT, France. It was decided that, at the outset, SEEPEX would manage an organized market with standardized products on a day-ahead market. In 2018 there were registered 18 participants.

The total amount of electricity traded in SEEPEX in 2018 was 2,318 GWh, which is 2.7 times more than in 2017. The share of electricity traded in the power exchange in relation to the electricity delivered to all end customers of electricity was 7.9%.In the wholesale market, the SEEPEX stock market share is 59%, where the wholesale market is actually a bilateral market (buying and selling electricity between suppliers).

The average annual base price was 50.1 €/MWh while the highest hourly rate was reached on 22 November 2018 at 06 p.m. arriving at the level of 126.8 €/MWh. The transmission system operator, EMS, has entered into contracts for emergency energy exchange or cross-border tertiary regulatory energy exchange in cases where the power system operation security or power supply of the country is compromised, either on a natural or commercial basis. In 2018, EMS concluded one-year contracts on a commercial basis with the transmission system operators of Hungary (MAVIR), Croatia (HOPS) and Romania (Transelectrica).

In June 2019, the European Commission adopted an updated Electricity Regulation 2019/943 as part of its Clean Energy Package. One of the provisions is a new emission limit of 550 grams of CO_2 of fossil-fuel origin per kWh of electricity as an eligibility condition for participation in capacity mechanisms.

Renewables

Increase of energy production from renewable sources is important in order to reduce import dependency, improve energy security, for environmental protection and for GHG emission reduction. In the primary energy production in Serbia for 2018, energy from renewable energy sources participated with 21% (2.146 Mtoe).

The largest part is biomass with 52%, followed by hydro at 46% and by wind, solar, geothermal and biogas with a total of 2% participation. In accordance with the Energy Community Ministerial Council Decision on adoption of the RES Directive (2009/28/EC), Serbia adopted the National Renewable Energy Action Plan (NREAP) in June 2013. Serbia committed to a binding target for energy from RES of 27% of gross final energy consumption (GFEC) in 2020, compared with 21.2% in the base year 2009. In order to achieve this Serbia plans to provide 2,563 Mtoe from RES utilization in 2020.

The share of RES in the electricity mix is projected to increase from 28.7% in 2009 to 36.6% in 2020 (RES-E), in heating and cooling from 25.6% to 30% (RES-H&C) and in the transport sector from 0% to 10% (RES-T), respectively. These sectorial targets are not binding and do not represent fixed targets for each individual sector, thus they can be changed, i.e. increased in case of quicker development of certain sectors with respect to others. There is progress in a number of new RES installations in Serbia, but dynamics of implementation are not as was expected. Table 5.223 illustrates the progress in NREAP implementation since the base year (2009) covering the three sub-sectors of electricity production, heating/cooling and transport.

Table 5.223 **Serbia – Actual development and projections in NREAP implementation**

Project	2009	2014	2015	2016	2017	2019
GFEC (Mtoe)	9.1	8.5	9.3	9.4	9.6	9.6
Share of RES - E %	28.7	40.68	38.86	29.15	28.71	30.11
Share of RES - H&C %	25.6	30.34	26.77	24.65	24.43	26,64
Share of RES - T %	0	0	0	1.23	1.18	1,14
Overall RES share %	21.02	22.73	21.00	20.98	20.60	21,44

*Scenario with applied EE measures
Source: Ministry of Mining and Energy

It is evident that Serbia is still below the planned RES share level in GFEC. There are economic, political and other reasons for this. Firstly, the average Cost of Capital (WACC) is higher than in other parts of Europe because of political instability and banks' distrust in the legal and judiciary system. Access to capital is expensive and banks have the perception of a high risk factor for RES investment in Serbia.

Furthermore, there is a shortage of institutional capacity and experience in the implementation of new technologies, as well as an evident chronic delay in by-laws and secondary legislations adoption of incentive measures for small-scale private investments, such as solar PV or solar water heaters.

Res -Electricity Sector

As defined in the Energy Development Strategy 2025-2030 and actual NREAP, Serbia should have already installed 1092 MW of RES by 2020, 1300 MW by 2025 and a further 1700 MW by 2030.

Besides the large hydropower electric plants owned by EPS with total power generation capacities of 2.986 MW, including 614 MW in pump storage, the government has delegated the investment in generation by utilization of renewable energy sources, to the private sector and to private-public partnerships, supported by incentive measures (Feed-In Tariffs).

From 2014 to the end of 2020 independent producers built 514 MW utilizing RES energy, in 121 Small HPPs, 107 solar–photovoltaic plants and tens of wind and biogas installations. Some additional plants (304 MW) are currently under construction or in a testing stage.

Privileged producers entitled to a feed-in tariff are paid by the state-owned electricity incumbent "EPS Supply", according to the power purchase agreements. The guaranteed purchase price in the form of a feed-in tariff is being passed on to customers through a surcharge applied to all electricity end-users. Current surcharge for all customers is 0.093 RSD/kWh. (~ 0.078 €/kWh).

Table 5.224 **Serbia - Independent privileged electricity producers in feed-in tariffs – 2019 (MW)**

Privileged RES	MW - Active	MW - On hold
Independent mini HPPs	69.4	28.7
Independent Solar PP	8.8	/
Independent Wind PP	330.0	236.0
Independent Biogas PP	22.5	37.0
Independent Biomass PP	2.4	2.4
Landfill gas and sewage gas PP	/	3.1
Waste fired PP	/	30.2
Fossil fired high efficiency CHP	21.9	14.0
Total	**455**	**351.4**

Source: Ministry of Mining and Energy

Table 5.225 **Serbia - electricity produced by privileged producers on Feed-in-tariffs (GWh)**

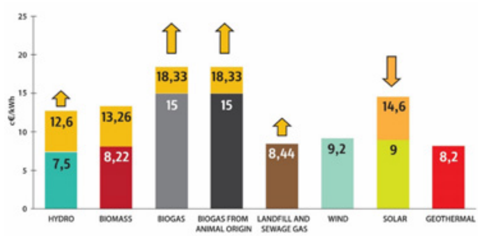
RES sources	2015	2016	2017	2018
Hydro	151.2	192.4	183.2	265.9
CHP High Efficiency	44.3	78.2	112.4	105.8
Biogas	22.0	34.1	71.3	95.5
Solar	10.0	11.1	11.1	10.5
Wind	0.4	26.2	48.4	150.4
Total	**227.9**	**342.0**	**426.4**	**628.1**

Source: AERS – Annual Report 2018

Privileged producers are exempted from balancing responsibilities costs during the entire 12 years. They also enjoy priority in the takeover of the total produced electricity into the transmission or distribution system, except if operation security is jeopardized.

With regard to the promotion of RES, Serbia has been applying the feed-in tariff model since 2009, and periodically revised and updated it as in 2011, 2013 and 2016.

Figure 5.261 **Serbia - Updates in Feed-in tariffs for privileged electricity producers**



Source: EPS

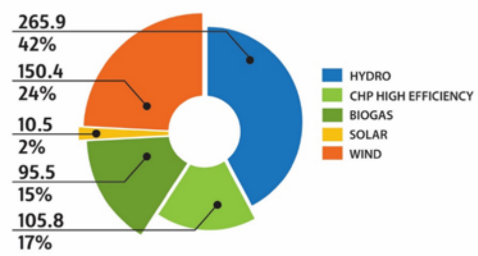
Table 5.226 **Serbia - Actual Feed-in tariffs for privileged electricity producers 2019**

Item No.	Type of power plant	Installed power (MW)	Feed-in tariff (c€/kWh)
1	Hydro power plant		
1.1		up to 0,2	12,60
1.2		0,2 - 0,5	13,933-6,667* P
1.3		0,5 - 1	10,60
1.4		1 -10	10,944-0,344* P
1.5		10 - 30	7,50
1.6	Using existing infrastructure	up to 30	6,0
2	Biomass power plant		
2.1		up to 1	13,26
2.2		1 - 10	13,82 - 0,56*P
2.3		over 10	8,22
3	Biogas power plant		
3.1		0-2	18,333 – 1,111*P
3.2		2 - 5	16,85 – 0,370*P
3.3		over 5	15,00
3.4	Plant fired by biogas from animal origin waste		18,33
4	Landfill and sewage gas power plant		8,44
5	Wind power plants		9,2
6	Solar power plants		
6.1	roof-mounted	up to 0,03	14,60 – 80*P
6.2	roof-mounted	0,03 – 0,5	12,404 – 6,809*P
6.3	ground-mounted	over 0,5	9
7	Geothermal power plants		8.2
8.1	Gas fired co-generation power plant	up 0,5	8.20
8.2		0.5 - 2	8,447 - 0,493*P
8.3		2 - 10	7,46
9	Waste fired power plant		8,57

Source: Ministry of Mining and Energy

Planned additional electricity installation (1092 MW) and production of (3635 GWh) by RES in 2020 was envisaged mostly for hydro, wind and biomass. In the current situation (end of 2020) there are new additional and installed RES capacities (514 MW) and 304 MW still in construction. In 2018, Serbia had a production by privileged producers in the amount of 628 GWh.

Figure 5.262 **Serbia - Electricity generated by privileged producers in 2018 – 628 GWh**



Source: EPS

Despite the considerable potential in renewable resources, there has been limited progress other than the hydroelectric sector mainly in the form of small hydro power plants. Hydro power generation is a proven and mature technology coupled with traditional national knowledge and experience in the construction of hydro power stations.

It took a few years for the new system of incentives to come to life, and then to gain investors' confidence in the functioning of the system, as well as in the preparation of appropriate projects especially for large power plants.

As announced by the government there will be a partial modification of the existing legal framework for the promotion of the use of RES, such as the introduction of tenders for large wind and solar power plants, as a mechanism that will enable the allocation of capacity and granting of the status of privileged producers according to the criterion of the lowest offered price.
Scaling up electricity from renewables will be crucial for the decarbonisation of Serbia's energy system.

Res - Heating Sector

As defined in the Energy Development Strategy 2025-2030, RES used for heating and cooling should increase from 1,059 ktoe in 2009 to 1,167 ktoe in 2020 which will amount to 10.2% of total energy used in this sector. Most of the change should be achieved by increased use of biomass.

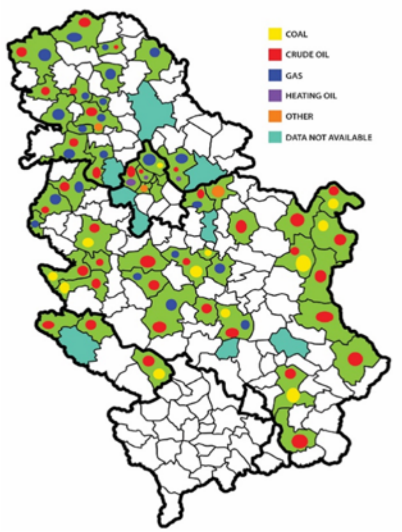
The use of biomass by CHP plants will need to increase by 33%, individual household use by 34%, biomass district heating systems by 16% and biogas CHP systems by 7%, compared to 2009. Direct supply of wood biomass from forests and other forested land for energy production in 2015 was 1,011ktoe and should increase to 1,200ktoe in 2020.

There are also the local district heating systems (DHS) in 58 cities and towns across the Serbia with total installed capacity of about 6.900 MW (42% in capital city of Belgrade), more than 2.100 km of distribution network and 23.500 heat-transmitting substations. The average age of the boiler units used in the distribution networks and heat-transmitting substations is 21-24 years. The primary energy sources used to produce heating energy are natural gas (77.7%), coal (8.8%), heating oil (13.5%) and sporadic application of biomass.

Currently about 47% of households in Serbian cities and towns are connected to local District Heating Systems while in rural areas coal and wood (especially in mountainous areas) are the main fuel sources for heating. Imported fossil fuels generate a serious deficit in the state budget (about 2 Billion €).

On the other hand, biomass availability is higher than planned consumption, so there is sufficient space for fossil fuel substitution with biofuels.

Map 5.68 **Serbia - Installation of District Heating Systems by Fuels**



Source: Ministry of Mining and Energy of the Republic of Serbia

In the energy balance of final energy consumption in Serbia in 2018 the use of biomass reached about 12%. In order to further increase this percentage, in the course of 2018, the Ministry launched a three-year project concerning the replacement of heating oil and coal as fuels in district heating systems with biomass.

Production and consumption of solid biomass for heating purposes includes not only firewood, but also pellets and briquettes. Biomass production in 2017 in Serbia was 1.084 Mtoe, of which the largest part of 0.804 Mtoe was consumed in households. The share of other renewable energies (like geothermal or solar) is marginal. On the consumer side, the final heating consumption in 2018 through district heating systems and industrial heating facilities amounted to 0.74 Mtoe (households 0.41 Mtoe, industry 0.21 Mtoe and others 0.12 Mtoe). Additionally, firewood and derived wood products final consumption in 2018 was 1.04 Mtoe. Households are the largest consumers (0.87 Mtoe) followed by industry (0.15 Mtoe).
Whenever possible, heat production is combined with electricity generation or other technological processes in which hot water is a by-product. Production of electricity and thermal energy for heating purposes takes place in the following plants:

- TPP Nikola Tesla A for district heating of Obrenovac (steam coal units)
- TPP Kostolac A for district heating of Požarevac\and Kostolac (steam coal units)
- TPP Kolubara A for district heating of Lazarevac
- CHP Novi Sad, Zrenjanin and Sremska Mitrovica, for process steam and district heating

The renewed project "Building heating pipeline "Belgrade – Obrenovac" using thermal energy from TPP TENT A – 600 MWth at the expense of reducing available capacity for electricity generation from 150 MWe, will provide heat for more than 50% of the consumption of the heating plant in New Belgrade.

There are good examples for biomass utilisation in district heating systems. The Sremska Mitrovica heating plant uses sunflower husks. One of Belgrade's heating plants uses pellets and wood. Biomass boilers are installed in Pirot, Priboj and Šabac and are used to heat public buildings, primarily schools. The other available biomass by-products and wooden pellets are currently exported to the EU.

So far, the state does not subsidize the production of heat from RES, since only feed-in tariffs for electricity production exist. In order to provide additional support for the activities related to energy production with the use of RES in combined heat and power production, the Government of the Republic of Serbia adopted the Regulation on Incentive Measures for CHP Generation.

According to the current legislation, local self-government bodies define the conditions for acquiring the status of privileged heat producer. Municipal self-governments monitor energy consumption, energy development planning, application of energy efficiency measures and the use of RES at local level predominantly for heating purposes. According to the existing rules, privileged thermal energy producers are the producers using RES in the process of thermal energy production and fulfilling the conditions in terms of energy efficiency. The local self-government unit prescribes incentive measures and conditions for acquiring the status of a privileged producer.

Eligible heat producers are entitled to subsidies, tax, customs and other exemptions. However, incentive mechanisms to increase the share of renewable energy in DHSs are very rare in the Western Balkans. Therefore, establishing and operating comprehensive incentive mechanisms is key to harnessing the great potential that DHSs can provide for the decarbonisation of the energy sector.

Res - Transport Sector

Alternative fuels and alternative energy sources represent one solution to the problem of environmentally friendly vehicles that do not produce harmful emissions and, in the case of Serbia, also decrease the usage of imported of fossil fuels.

While a certain framework has been established for electricity and heat production from RES activities, the use of Renewable Energy Sources in the Transport sector (RES-T) is still very limited. The actual share of energy from renewables in transport, instead of the 10% target is close to 0%. Serbian petrol stations do not offer yet organic fuels, and for many years they have been waiting for a regulation on the obligation to mix biofuels in diesel fuels.

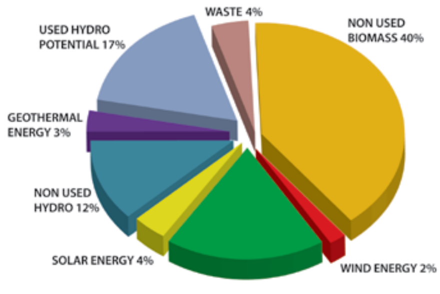
The unfavorable business climate is further accentuated by uncompetitive taxation (excise duties) and lack of incentives. Moreover, some key regulatory measures are not implemented or are missing, such as monitoring and reporting requirements, or certification. Reliable data on the consumption of biofuels in the transport sector will be available upon the adoption of by-laws which regulate the sector of biofuels in accordance with the Directive 2009/28/EC. There is considerable agricultural resource within Serbia to produce biofuels and the country is already a major exporter of agricultural raw materials for biofuel production elsewhere. Given Serbia's strong agricultural output there is considerable potential to supply feedstock for local biofuel production.

Hundreds of farmers and enthusiasts in Serbia have taken "energy self-sufficiency" seriously and are producing fuel for their tractors, cars or heating up their homes for half the price from a gas station. The government is expected to prescribe in more detail the share of biofuels in the market, reporting entities of the system for placing biofuels on the market and their obligations. Only biofuels certified to fulfil sustainability criteria may be taken into account when estimating the achievement of objectives set by the NREAP.

Res - Potential in Serbia

Serbia has a great potential for the development of renewable energy. Serbia's RES technical potential is estimated at 5,65 Mtoe per year. Up to now only ~ 2 Mtoe (35%) of this potential is utilised. Some 1,121 Mtoe (2018) of biomass (mainly as fuel wood) and 0,979 Mtoe of hydro energy (2018) of this potential is already in use. The further development of available potential must be justified in terms of sustainability and taking into account economic, environmental and social feasibility parameters.

Figure 5.263 **Serbia - RES – technically usable potential 2018**



Source: Updated data from Energy Sector Development Strategy of Republic of Serbia for the period by 2025

5

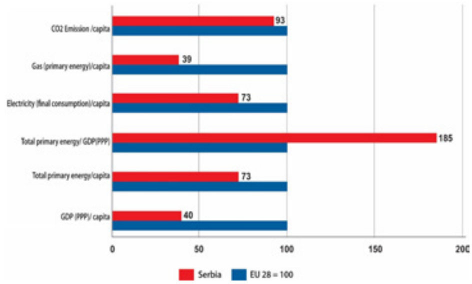
Energy Effiiency and Cogeneration

Energy efficiency (EE) is one of the main objectives in the national energy strategy, helping to enhance energy security, contribute to economic growth and ensure environmental sustainability. Policy creation and implementation of the EE measures is assigned to a department in the Ministry of Mining and Energy.

On the supply side there are a lot of activities (by companies at national level) dedicated to improving energy efficiency in energy transformation, transmission and distribution sectors. On the consumption side, planned EE actions include measures in the residential building sector, public and commercial building sector, industrial and the transport sector. Measures include legislative and infrastructure procedures, that will lead to a reduction of final energy consumption. Compared to the European Union, gross domestic product of Serbia (per purchasing power parity) in 2018 was at 40%, consumption of total primary energy per capita at 73% and final electricity consumption at 73%. Energy intensity, defined as total primary energy consumption per gross domestic product unit (per purchase power parity) was 1.8 times higher than the European average.

The greater energy intensity stems partly from inevitable technical losses in the process of primary energy transformation (mostly lignite) into electricity. Serbia's economy is characterised as high energy intensive. This is also due to low efficiency in industry and households as well as because of aged technologies that are still in use. Further differences in the structure of final energy consumption, compared to the EU, is the high share of household consumption in Serbia. Moreover, it should be noted that industrial production in Serbia today is significantly lower than in the late 80's.

Figure 5.264 **Serbia - Comparative energy indicators of Serbia and EU 2018-**



Sources: IEA, Eurostat, WB, SORS Statistical office RS, compiled by AERS

The framework of the EE activities in Serbia can be illustrated by two main documents, by two laws that regulate final energy consumption and energy sources in Serbia. They are:

- Energy law ("Official Gazette of the Republic of Serbia", no. 145/2014)
- Law of efficient use of energy ("Official Gazette" no. 25/2013)

Requirements of the Directive 2006/32/EC about efficiency of final energy consumption and energy services (ESD) have been applied in Serbia through these two laws. In the meantime, Directive ESD was replaced by a newly formed Directive 2012/27/EU about Energy Efficiency (EED), whose obligatory implementation for the contracting parties of the Energy Community started at the end of 2017.

In line with its commitments under the Energy Community Treaty, Serbia approved its first National Energy Efficiency Action Plan (NEEAP) in 2010. This plan detailed the activities that were to be undertaken in various sectors with the overall aim of reducing energy consumption by 9% between 2010 and 2018. An updated NEEAP (2013-2015) has been adopted in 2013.

The third NEEAP (2016 to 2018) was adopted in late 2016 and was prepared in a format defined by Energy Community and in accordance with the requirements of Directive 2006/32/EC. It also included a number of elements of the Energy Efficiency Directive (EED) 2012/27/EU, by which the indicative target for Serbia is that primary energy consumption does not exceed 17,981 Mtoe and final energy consumption does not exceed 13,103 Mtoe in 2020.

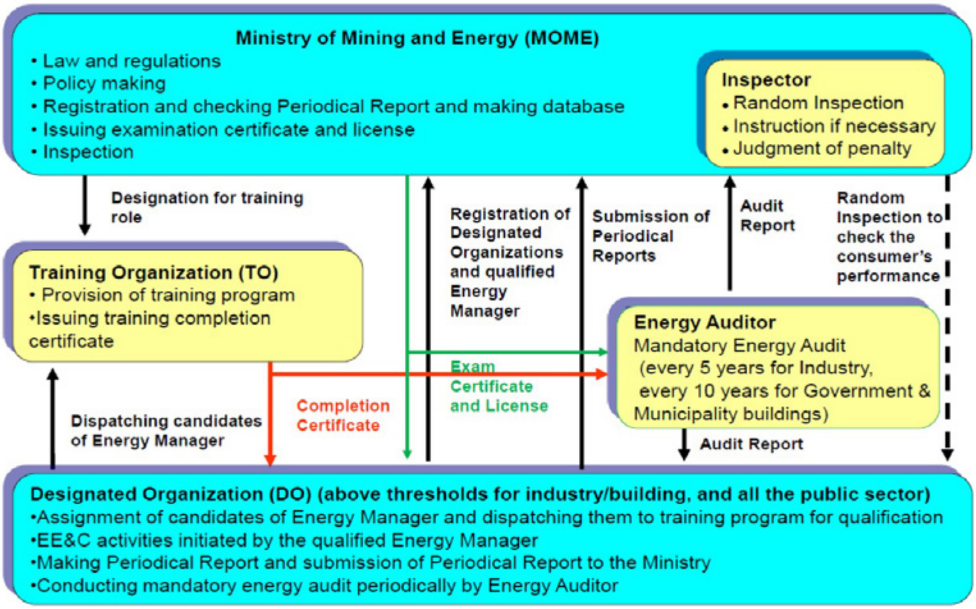
The realized data for 2018 show the consumption of primary energy (15,802 Mtoe) and the final energy consumption (8,599 Mtoe) – both significantly bellow the projected consumption. Periodical creation of NEEAP (4th - for the period from 2019 to 2021, and the 5th - for the period 2022-2024) will include analysis of existing measures from previous plans and a list of new ones.

In line with the Law on Efficient Use of Energy provisions, in 2017 Serbia introduced an Energy Management System (SEM) project supported by JICA, Japan and financed by the Global Environment Fund and UNDP. SEM covers approximately 70% of final energy consumption. Target sectors for energy audit (by licensed energy managers) and energy efficiency improvements include:

• municipalities with over 20.000 inhabitants,
• commercial buildings with consumption more than 1000 toe,
• industrial sector with consumption more than 2500 toe and
• all government facilities with working space more than 2000m2

5

Table 5.227 **Serbia - Framework of Energy management system – SEM**



Source: Ministry of Mining and Energy

SEM identified 79 cities and towns, 72 industrial facilities and 8 enterprises in trade and the rest of the public sector – all fulfilling the scope for audit and potential improvements. The Ministry of Mining and Energy has authorized the Faculty of Mechanical Engineering of Belgrade University to perform training of authorized Energy Managers and energy advisers and has established the energy management system data base – SEMIS. There is a rulebook about type of data, deadlines, manner and form in which audits are to be carried out and findings submitted. As of March 2018, 180 individuals obtained a license to become an Energy Manager.By a decree in 2014, the government introduced a new financing instrument – an energy efficiency budgetary Fund (and a 2014 Energy efficiency measures financing Programme) – and allocated 2.6mill € from the state budget to it. Those monies are used in 11 municipalities for improving heating facilities.

In 2016, the Fund had assets of 1.5mil€ and the funds were distributed to 15 communities. Generally, these funds are small and grossly insufficient for the implementation of all planned energy efficiency projects.

For example, the necessary funds for implementation of measures to improve EE of buildings in the public and commercial sectors (planned for implementation in the 3rd NEEAP) are estimated at 58mil€ per year.

Hence it is necessary to improve the current operation of the budgetary Fund or change the secondary legislation. Fund's increased resources may be achieved through donations, fees or by favorable loans from international financial institutions.

The overall results of the Budgetary Fund for 4 years are as follows: Investment of 3.5 mil€ has been secured for 39 projects (27 finished so far) with 30% contribution by municipalities, expected energy savings of about 9.4 GWh and a reduction of CO_2 emissions of about 4150 t/year. The state financing for energy efficiency has been improved in 2018. The government introduced a fee for all energy sources (electricity, oil products, natural gas) in the amount of 0.015 RSD/kWh (~0.012 c€/kWh) for electricity, 0.15 RSD/l for oil products, and 0.15 RSD/m³ for natural gas. The expected revenue from these fees is about 9 mil €/year.

By Energy Community's assessment, Serbia has achieved a relatively high level of implementation of the EE acquis. It is understood that success in the implementation of previous NEEAPs is primarily based on the implementation of large systemic measures that have covered broad end-users of the population. Good practices that had been developed and introduced include:

- Introduction of energy labeling scheme aligned with the EU practice. From producers of electricity, heat generators, water heaters to household appliances
- Improvement of the thermal envelope of the public and private buildings
- Modernization of indoor and outdoor public lighting systems
- Promotion of ESCO-energy service companies (ESCOs cover 35 street lighting systems)
- Ongoing certification of buildings, secondary regulations of the Law on Construction and Planning
- Introduction of Energy Management System (SEM), based on Japanese experience

All results on the achievements of the 9% energy savings by 2018 should have been available in the 4th NEEAP which was planned to be adopted in 2019, but the work is still ongoing.

Currently, the Ministry for Mining and Energy has identified 150 new projects which had been realized until 2018 with total energy savings of 17 ktoe (197 GWh). For 2020 energy efficiency targets Serbia calculated both an annual 1% renovation target for central government buildings (57 buildings, about 405.000 m²) and a 0,7% target under the energy efficiency obligation scheme. Through the auspices of the Energy Community, significant offers from international financial institutions (IFIs) and financing facilities providing different funds, donations and credit lines with related technical support have been secured.

Some of the successful examples are as follows:

- German development bank KfW has launched two subsidized loan programs, with technical assistance, "4E Facility" and "Eco-loans" for energy efficiency improvement in public and private legal entities. Total amount of 120 mil€ is disbursed to local commercial banks to finance investments.
- The project "Rehabilitation of the District Heating System" started in 2012 and ended in 2019. 68 projects, worth over 52 mil€ were completed. Technical measures financed largely from the KfW soft loan (45 mil€) and the rest of funds was contributed by the Republic of Serbia.
- Improving energy efficiency of public facilities in four cities in Serbia is covered in the "Energy Efficiency and Energy Management in Municipalities" (PEEUEO) project and is a collaboration between Swiss and Serbian government. It covers 26 buildings (17 primary schools, 6 kindergartens, 1 high school and 2 health facilities). The project worth is 10 milCHF, of which the Swiss donation is 88%.
- The ongoing program for the rehabilitation and renovations of Central Government Buildings is financially secured by the state Budgetary Fund for EE and support of 45mil€ investment loan by the Council of Europe Development Bank. The inventory (total useful floor area of over 250m2) and 1% target for central government buildings that must be renovated, was adopted by the government in August 2018.

The European Bank for Reconstruction and Development (EBRD), the European Investment Bank (EIB), the World Bank and German development bank - KfW are becoming increasingly engaged in providing affordable lending terms to large scale energy efficiency schemes. Despite Serbia's progress in implementing the energy efficiency framework enacted by the Energy Community Treaty there are still a number of barriers such as the energy price distortions, subsidies, lack of consumption-based billing for heating, financing problems, lack of by-laws, lack or institutional capacity, lack of public awareness etc.

The residential sector still consumes the largest share of final energy. Serbia has high carbon footprint due to a legacy of high-energy intensity and inefficiency in buildings and industry. On the other hand, Serbia has a tremendous potential to improve energy efficiency. It is generally realized that energy efficiency is the cheapest, cleanest and most secure source of energy.

CHP Installation

Construction and generation of Combined Heat and Power Plants (CHP) is planned, promoted and governed by a series of laws, bylaws, strategies, action plans, decrees, and regulations:

- The Law on Energy (Official Gazette of the RS 145/14), Articles 2, 3, 16, 20, 21, 30, 57, 70, 74, 80, 85, 345, 380, 386.
- The Law on Efficient Energy Use (Official Gazette of the RS 25/13). Articles 5, 45, 46 introduce certain requirements for the construction of new and reconstruction of existing heat and electricity generation facilities.
- Energy Sector Development Strategy of the Republic of Serbia for the period by 2025 with projections by 2030 (Official Gazette of the RS 101/15).
- Energy Strategy Implementation Program for the period from 2017 until 2023 (2017).
- 3rd National Energy Efficiency Action Plan (2017) establishes, for the first time, EE measures in the energy generation sector and expected results of primary energy savings.
- Regulation stipulating the requirements and procedure for acquiring the status of a privileged power producer (Official Gazette of the RS 56/16).
- Regulation stipulating incentives for the production of electricity from renewable energy sources and from high-efficiency electricity and thermal energy cogeneration - (Articles 1, 2, 4, 7) (Official Gazette of the RS 56/16).

Future Power Systems in Serbia and SEE region will have different patterns from those observed today. Less lignite-fired power plants, more RES, more energy efficiency and an increased need for flexibility. Combined Heat and Power (CHP) production plants will play a significant role in energy transition and the inevitable decarbonisation.

Table 5.228 **Serbia - CHP installations in 2019**

CHP installations	Fuel	Electricity MWe	Heat MWt
Public CHP Novi Sad	Natural gas/Oil	250	355
Public CHP Zrenjanin	Natural gas/Oil	110	140
Public CHP Sremska Mitrovica	Natural gas/Oil	32	33
Industrial CHPs (7)	Natural gas/Oil	10	
Industrial CHPs (5)	Biogas	5	

Source: Ministry of Mining and Energy

The generation of public CHPs in 2018 was 351 GWh in electricity and 0.039 Mtoe in heat (steam and hot water) supplying local district heating systems and some industrial customers. Industrial CHPs utilizing natural gas and biogas in combined processes, along with additional industrial energy auto producers (in closed systems) in 2018 generated about 543 GWh in electricity and 0.264 Mtoe in heat.

After certain technical modifications in some of the EPS thermal power plant units, during certain periods of the year, aside from their main activity of electricity generation, they are delivering additional heat and hot water for industrial and local district heating purposes in municipalities of Obrenovac, Lazarevac and Pozarevac. Three thermal power plants of Panonske CHPs produce heat for the cities of Novi Sad, Zrenjanin, and Sremska Mitrovica.

The renewed project of heat pipeline connecting Thermal Power Plant Nikola Tesla A with the city of Belgrade (29 km), will connect the 600 MWth New Belgrade Heating Plant with the aim of supplying base load heat for the entire heating season. This project will place part of the said TPP in the CHP regime, and increase heat supply security for the largest heat consumer in Serbia. Construction contract valued at EUR 195 mil. was signed with the Power Construction of China, with a three-year implementation period. Promoting heat and electricity produced by high-efficiency combined heat and power plants (CHP) is part of the energy efficiency policy aimed at increasing energy efficiency in the power/heat sector.

The status of a privileged power producer for a power plant, and/or part of a power plant for high-efficiency electricity and heat cogeneration with an installed electrical capacity of up to 10 MW requires an annual efficiency level of 75%. The total annual efficiency level of a cogeneration power plant (η) is the ratio between the total net energy produced (electricity and heat) and energy values of consumed primary fuels. Current installation (March 2020) of highly efficient cogeneration with the status of privileged CHP producers is at the level of 26 MW and additionally 9.9 MW with the temporary privileged power producer status.

Three CHPs in District Heating Systems of Belgrade and Novi Sad with natural gas-fuelled high-efficiency plants already belong to the group of privileged power producers. Serbia has a major CHP cogeneration potential in the following sectors: industry, district heating systems, hospitals, farms, hotels, schools and kindergartens. Industrial companies that incorporate natural gas-fuelled high-efficiency plants for combined heat and power generation (CHP) up to 10 MW are entitled to acquire a privileged power producer status and receive an incentivised purchase price for the electricity delivered.

The Waste Management Strategy of Serbia (2010-2019) refers to incineration of waste, its energy use and integrated approaches to waste management. The Decree governing incentives for renewable energy sources includes support for power plants using municipal waste as a fuel.

Beyond electricity and heat generation, there are a number of advantages to considering waste-to-energy with a view to the significant reduction of waste volumes and landfill space, especially important for urban areas.

The Vinca project (12 km from Belgrade) as part of the Waste Management System for the City of Belgrade is a Private Public Partnership designed to improve the current solid waste disposal practice. The project is the first project of its kind in Serbia. It includes an Energy from Waste facility with the nominal combustion capacity of about 340,000 t/year of municipal waste, which will under the CHP regime generate a combination of electricity (~192 GWh/y) and heat (~175 GWh/y). Maximum gross electricity output will be 32,4 MWe and maximum heat output to district heating 56,5 MWth.

A PPP contract was signed in September 2017 between the City of Belgrade and Suez, France, ITOCHU, Japan and Marguerite Fund, Luxemburg. This project valued at EUR 370 mil. will be in full operation by late 2022. In a transition agenda, natural gas is likely to become competitive with lignite, especially in industrial and community CHP units. Since 2013, NIS, Petroleum Industry of Serbia has launched eleven small CHP gas generation units in oil and gas fields, with the total capacity of 9.6 MW.

Similarly, the Serbian oil company NIS, under a joint venture with the Gazprom Energoholding, completed construction of 200 MW combined steam and gas cycle CHP plant in Pancevo. The main purpose of this CHP plant inside the NIS' oil refinery complex in Pancevo is to meet the growing need of the refinery for power and process steam. CHP plant will consume about 300 mil. cubic meters of natural gas per year, while its annual electricity generation will be around 1,400 GWh. Up to 65% of the electricity generated will be sold on the domestic and regional open electricity market, while also covering the needs of the Pancevo refinery for electricity and steam. The plant is not part of any support scheme and no subsidies are planned for its operation. The project costs are valued at some EUR 180 mil. and it is completion is expected by mid-2021.

As announced by Gazprom Energoholding, the construction of four more natural gas fuelled CHP plants in Serbia is also under consideration, in Belgrade, Novi Sad, Nis and Kragujevac.

Energy Investment Outlook

Energy Investment

Projects under construction	**mill €**	**Period**
ELECTRICITY		
Thermal Power plants		
EPS - New block TPP Kostolac B3, 350 MW (2200 GWh)	716	up to 2020
NIS - CHP 140 MW (910GWh) on Natural gas, Pancevo	180	up to 2020
EPS - Thirteen projects for emission reduction SO_2, NOx	536	up to 2023
Wind Power Plants		
Private investors - Seven new wind farms up to 500 MW (1303GWh)	706	up to 2020
EPS - Wind park 66 MW (150 GWh) East Serbia	97	
Solar PV plants		
EPS - Solar plant 9.95 MW (13GWh) Petka, near Kostolac		
EPS - Solar plant 97.2 MW (115GWh) near Kostolac	84	up to 2025
Transmission and Distribution		
EMS - Trans-Balkan corridor 400KV phase 1	164	up to 2023
EPS - Reconstruction of old and construction of new 110/x KV substations	196	2017-2023
EMS - Reconstruction and reinforcing of 110 KV power lines and cables	49	2017-2023
EPS - Metering infrastructure and distribution network automation	90	2017-2023

5

COAL PRODUCTION		
EPS - Opening new mine fields - replacement capacities, Kolubara, Kostolac	1125	2017-2023
EPS - Coal quality management in Kolubara and Kostolac basins	150	2018-2025
EPS - Measures for efficient coal production	81	2017-2020
OIL & PETROLEUM		
NIS - Refinery Pancevo reconstruction and modernization "Deep Processing"	330	2017-2020
Transnafta - petroleum product pipeline Pancevo - Smederevo	30	up to 2022
Ministry ME - Mandatory stock of crude oil and petroleum	12	2017-2022
NATURAL GAS		
Transportgas - Interconnection Serbia - Bulgaria 109km	86	up to 2022
Gastrans – Main transport pipeline Bulgaria-Serbia-Hungary 403 km	800+	up to 2021
Banatski Dvor - Underground Gas storage from 450 to 800 mil m^3	65	2020-2023
Srbijagas - Main and distribution gas pipelines	378	2017-2023
HEAT		
EPS - Heating pipeline TPP NT Obrenovac - Belgrade 600 MWth	165	up to 2023
District Heating Systems - Transition to boilers on biomass	100	up to 2021
Total	**6 140+**	

Potential projects	**mill €**
Hydro PP Srednja Drina, 321 MW	819
Hydro PP Velika Morava, 148	360
Small hydro PP, 191 locations, 387MW	500
PS Hydro PP Bistrica, 680 MW (4x 170MW)	560
PS Hydro PP Djerdap 3, Phase 1, 600MW (2x 300MW)	400
Thermal PP Nikola Tesla B3, 750MW	1600
Thermal PP Kolubara B, 2x 375MW	1500
Thermal PP Novi Kovin, 2x 350MW	1330
Thermal PP Stavalj, 300MW	700
Thermal CHP Novi Sad, 340MW	400
CHPs - Belgrade, Nis, Kragujevac, Novi Sad	819
Transportgas - Interconnection Serbia – Romania 6km	6
Transportgas - Interconnection Serbia – Croatia 95 km	32

References

(1) SORS - Statistical Office of the Republic of Serbia
https://www.stat.gov.rs/en-US/

(2) AERS - Energy Agency of the Republic of Serbia
http://aers.rs/

(3) EMS - Elektromreza Srbije JSC Belgrade, http://ems.rs/index.php?lang=2

(4) EPS - PE Electric Power Industry of Serbia, Belgrade, http://www.eps.rs/eng

(5) Srbijagas - PE Srbijagas, Novi Sad, http://www.srbijagas.com/

(6) NIS - NIS JSC, Novi Sad, https://www.nis.eu/en/

(7) SEPEX - SEPEX SPOT, Belgrade, http://seepex-spot.rs/en/

(8) MoME - Ministry of Mining and Energy, https://www.mre.gov.rs/

(9) Ministry of Finance, https://www.mfin.gov.rs/en/

(10) Energy Community Secretariat, https://www.energy-community.org/

(11) Energy Law, Official Gazette of the Republic of Serbia, No 145/2014

(12) Energy Sector Development Strategy of the Republic of Serbia for the period 2015-2025 with Projection up to 2030, Official Gazette of the RS, No 101/2015

(13) Regulation Establishing Implementation Program of Energy Development Strategy of the RS until 2025 for the period 2017 to 2023, Official Gazette of the RS, No 104/2017

(14) National Action Plan for renewable energy sources in the RS, Official Gazette RS, No 53/2013

(15) National Action Plan for Energy Efficiency of the RS, Official Gazette RS, No1/2017

(16) Transmission System Development Plan of RS for the period 2018-2027, EMS JSC, 2018

(17) Regulation on limit values of air emissions from combustion plants, Official Gazette No 6/2016

(18) Transmission System Development Plan for the period 2017-2026, Srbijagas, 2016

(19) EUROSTAT - Energy balance sheets 2017 data, Statistical books 2019 edition

(20) EnC - Analyses on system adequacy and capacity mechanism in the Western Balkans, 2019

(21) EnC - WB6 Electricity Monitoring Report, May 2019

(22) IMF - Republic of Serbia - Third Review Under the Policy Coordination Instrument, Dec. 2019

(23) IRENA - Renewable Energy Market Analysis, Southeast Europe, 2019

(24) MoME - Third Annual Report under the Energy Efficiency Directive for 2018

(25) MoME - Progress Report on the Implementation of the NREAP for 2016 and 2017

(26) MoME - Republic of Serbia Security of Supply Statement, Year 2018

(27) EnC - The State of Gas Market Integration in the Energy Community, June 2018

(28) EPS - Electric Power Industry of Serbia, Technical Report 2018

(29) Western Balkans Investment Framework – Investing in Clean Energy in the WB, 2019

(30) European Commission – EU Candidate Countries Economic Quarterly 4th Quarter 2019

(31) Ministry of Finance of the RS – Economic Reform Programme for the period 2020-2022

(32) BP - Energy Outlook, 2019 Edition

(33) Exxon Mobil - 2019 Outlook for Energy: a Perspective to 2040

(34) EnC - Draft Study on 2030 overall targets (EE, RES, GHG) for Energy Community, 2018

(35) Development Agency of Serbia - Why Invest in Serbia, 2019

(36) World Bank - Structural Reforms to set the Growth Ambitions, New Growth Agenda, 2019

SLOVENIA

Slovenia

Economic and Political Background

Slovenia's GDP declined at a sharper pace of 4.5% year-on-year in the fourth quarter of 2020, below the 2.4% contraction seen in the third quarter. GDP fell 6.7% in 2020 as a whole after growing 3.2% in 2019, marking the worst drop since the Great Recession.

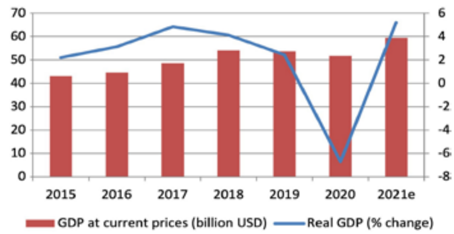
Household spending fell 14.5% in Q4 2020, which was significantly below Q3's 0.6% contraction, dragged down by the tightening of restrictions throughout the quarter. However, public consumption improved to a 2.8% increase in Q4 (Q3: +1.3% y-o-y). Meanwhile, fixed investment rebounded, growing 2.0% in Q4 and contrasting the 0.8% decrease logged in the prior quarter, amid a robust construction sector.

Exports of goods and services contracted at a softer pace of 0.4% year-on-year in the fourth quarter (Q3: -9.5% y-o-y). In addition, imports of goods and services declined at a milder rate of 2.0% in Q4 (Q3: -12.5% y-o-y), marking the best reading since Q1 2020. While exports and imports of goods returned to growth, services trade was depressed by muted travel and tourism.

Going into 2021, the economy should benefit from the recent easing of restrictions in February and the likely further lifting of lockdown measures in the coming months, which should drive a rebound in private consumption. However, delays in the vaccine rollout and a slower-than-expected resumption of international trade pose downside risks to the outlook. IMF estimates that Slovenia's GDP will expand by 5.2% in 2021, significantly higher than -6.7% in 2020.

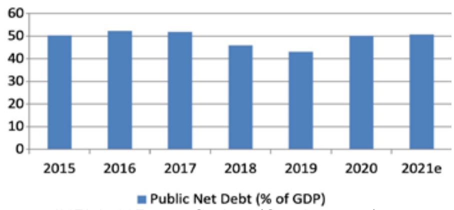
After the motion of no confidence against Slovenia's Prime Minister Janez Janša failed to secure a parliament majority due to the lack of support of DeSUS members of the parliament, the proponent of the vote, DeSUS president Karel Erjavec stepped down as president and also left the party. The government support that grew stronger with the occasional support of DeSUS parliamentarians was weakened when a split happened in the coalition member Modern Centre Party. Eventually, a new non-aligned parliamentary group was found out of the former SMC and DeSUS members of the parliament and the developments left the parliament split almost exactly in half, which became evident at a recent vote against the current Speaker Igor Zorčič.

Figure 5.265 **Slovenia's GDP and its annual GDP growth**



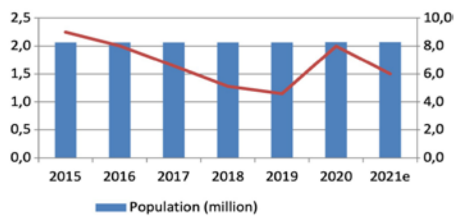
Source: IMF World Energy Outlook (October 2020)

Figure 5.266 **Slovenia's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.267 **Slovenia's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

5

Energy Policy

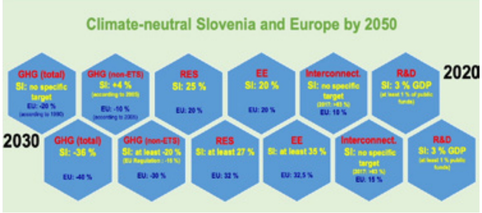
National Energy Policy

The government of Slovenia laid down its energy policy objectives and main priorities for the development of energy system in its Resolution on the National Energy Programme (adopted in June 2004) and with the Energy Act (latest revision from October 2019). The Energy Act provides a legal basis for the adoption of national strategic documents that will determine the long-term trend in energy supply and use. Unfortunately, since 2010 Slovenia was unable to reach the national consensus and adopt a new National Energy Strategy. The latest attempt failed in 2018 when the National Energy Concept was not adopted. Although the National Energy Concept (NEC) was strongly debated there was no actual agreement on a final framework. However, it is promising that despite the fact that the NEC was not adopted, national policy follows the recommendations and requirements of the "Clean Energy for all Europeans" Package.

By the end of February 2020, the Slovenian government adopted the country's first National Energy and Climate Plan (NECP). In the context of NECP, the main goal of the Slovenian national energy policy is to ensure secure, sustainable and competitive energy supply. At policy level, energy efficiency is perceived as the most important instrument for the future sustainable growth.

The new Slovenian NECP has been recognized as the first step towards establishing a solid base for further development of the national economy in the framework of its transformation towards low-carbon society and reaching goals of 2050. In order to avoid possible future problems the government has to develop a comprehensive follow-up plan to improve and accelerate activities for the implementation of the proposed measures and projects. NECP is foreseeing support and promotion of investments in new "climate neutral" technologies, renewable energy, energy efficiency as well as the comprehensive improvement of the electricity distribution network. An overview of key energy and climate policy goals of EU and Slovenia for 2020 and 2030 is shown in Figure 5.268.

Figure 5.268 **Key energy and climate policy goals of Slovenia for 2020 and 2030**



Source: NECP

Regarding the share of RES in the final energy consumption Slovenia is facing many challenges. Due to the high share of transport in the final energy consumption it is more difficult for Slovenia to proceed at the same pace as the other countries because the permitted share of RES in transport fuels is, due to requirements from engine manufactures, still relatively low. This means that in order to reach higher overall share of RES in final energy consumption, a significant increase of RES share in other sectors, in electricity production and heating, is required (see Table 5.229).

Table 5.229 **Overall and sectorial RES targets for Slovenia**

	2020	2022	2025	2027	2030
Renewable contribution as a share of energy from renewable sources in gross final consumption of energy in 2030 and indicative trajectory	25% 21.1% in 2018	25.4%	25.9%	26.3%	SI 27% EU 32%
RES -H&C share*	36.4%	36.8%	37.3%	38.9%	41%
RES - E share	33.5%	35.0%	37.2%	39.2%	43%
RES - T share	10.2%	11.5%	13.4%	16.1%	21%
RES - T share as contribution to overall target	10.8%	11.8%	13.2%	14.1%	15%

Source: NECP

Public acceptance in Slovenia, of the need for the further development and utilization of RES, namely hydro and wind power plants, similarly to other countries, is relatively low and represents a crucial obstacle for reaching higher shares of RES in electricity and in the final energy consumption. In the framework of the NECP, significant potential for the future increase of the electricity production from solar PV has been identified. However, it also means that accelerated development of the electricity distribution network must be ensured. The electricity distribution network has been recognized as the backbone of the transition to a carbon neutral society since it must be capable to accept and absorb a larger number of heat pumps, electric vehicles and electricity generation from solar PV without significant disturbances in power quality for the final consumers. In this context and considering the current situation (environmental constrains, long lasting spatial planning procedures, strong opposition from local communities, results of Strategic Environmental Assessment for NECP) the Slovenian objective of 27% renewable share in gross final energy consumption for 2030 seems very ambitious.

Slovenia is also in the process of preparing its Long-Term Strategy to achieve the greenhouse gas emissions reductions needed to meet commitments under the Paris Agreement and EU objectives. National ambition is to reach climate neutral Slovenia by 2050. Hence, the activities related with the preparation of the Long-Term Strategy and the NECP are harmonized.

Governmental institutions

Ministry of Infrastructure, Energy Directorate is the main governmental institution responsible for energy in Slovenia. The Ministry is responsible for cooperation in preparation and implementation of EU's energy and climate legislation, preparation of national legislation in the field of energy, preparation of strategic documents and action plans and implementation of measures to reach set targets in the fields of energy efficiency, renewable energy sources, security of supply and sustainable development of energy systems. Ministry of Infrastructure is working in cooperation with other ministries i.e. Ministry of Environment and Spatial Planning that is responsible for environment, climate action and reduction of air pollution, Directorate for transport at Ministry of infrastructure, responsible for transport policy in Slovenia.

The Energy Agency is responsible for the following tasks:

- regulation of the network activities, which covers economic regulation of all electricity and gas system operators and the regulation of the network with respect to issuing consents to the general acts
- regulation of the supply of heat and energy gases
- ensuring a reliable supply of natural gas
- promoting the production of electricity from renewable sources and cogeneration
- promoting efficient use of energy
- monitoring of the electricity and natural gas market
- supervising the providers of energy operators' activities
- protecting the rights of consumers

Borzen's principal activity is the implementation of public service obligation relating to the organization of the electricity market that includes organization of the electricity market in the strict sense and the activities of the Centre for RES/CHP Support which administers the electricity feed-in support scheme for RES (renewable energy source) and CHP (high-efficiency cogeneration) power plants.

ELES is the operator of the electric power transmission network of the Republic of Slovenia. ELES endeavors to strategically, responsibly and sustainably plan, construct and maintain Slovenia's high-voltage transmission network in three voltage levels: 400 kV, 220 kV and a part of 110 kV.

Plinovodi d.o.o. is a company managing the natural gas transmission network. Their main operational goal is provision of long-term, reliable, high quality, price competitive and environmentally acceptable transmission of natural gas.

The HSE Group is the largest producer and seller of electricity from domestic sources on the wholesale market in Slovenia and the largest Slovenian producer of electricity from renewable sources. Their other activities include extraction of lignite, provision of auxiliary services needed for the functioning of the electricity system in Slovenia, and management and implementation of energy and environmental projects.

GEN energija is the second largest producer of electricity in Slovenia producing and selling electricity from the Nuclear power plant at Krško, Sava hydropower plants and Thermal power plant Brestanica. It is also very active in energy trading through its daughter company GEN-I.

Eco Fund's main purpose is to promote development in the field of environmental protection, energy efficiency and renewable energy sources. It is the only specialized institution in Slovenia that provides financial supports for this kind of projects. The financial assistance is offered mainly through soft loans from revolving funds and since the year 2008 through grants.

Energy Demand and Supply

National energy demand

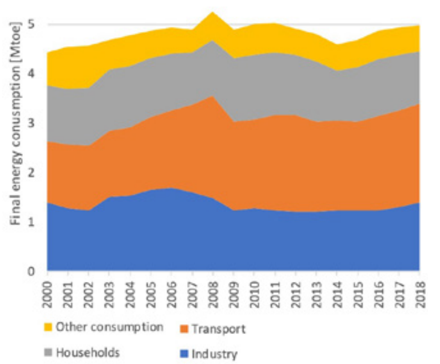
In 2018 Slovenia's total final consumption (TFC) reached 4.97 Mtoe, being 0.6% higher than the year before. Compared to 2000, TFC was higher by 12.4%. The highest TFC was reached in 2008 with 5.26 Mtoe. Since 2007, the transport sector has had the largest share in total final consumption. Its share increased from 28% in 2000 to 36% in 2007 and 40% in 2018. Before 2007 industry was the most important sector. In 2018 its share was 28%. Households in 2018 represented 21% and other uses 11%.

The transport sector is the only sector where energy use increased in the period between 2000 and 2018, being 65% higher in 2018 compared to 2000. Energy use in industry decreased by 1%, in households by 5% [1] and in other sectors by 22%.

The most important fuels are liquid fuels with 46% share in 2018 (i.e. 2.30 Mtoe), followed by electricity with 24%, renewables and waste with 14%, gaseous fuels with 12%, district heat with 4% and solid fuels with 1%.

Non-energy use amounted to 53 ktoe in 2018 decreasing by more than half compared to 2000 (57%). First data for 2019 indicates that final energy consumption will be slightly lower than the year before.

Figure 5.269 **Sectoral structure of final energy consumption in Slovenia during the period 2000-2018**



Other consumption includes commercial and public services, energy use for non-road machinery in agriculture and forestry
Source: SORS

Table 5.230 **Final energy consumption in Slovenia (Mtoe)**

	2000	2010	2017	2018
Industry	1,40	1,27	1,29	1,38
Transport	1,23	1,79	1,96	2,00
Households	1,12	1,33	1,12	1,07
Other consumption	0,68	0,61	0,57	0,52
Final energy consumption	4,43	5,00	4,94	4,97

Source: SORS

[1] Statistical data for Renewable energy use in households have been improved in 2009 resulting in large increase of its use therefore the trend is being influenced by this. On the other hand energy data for other sectors does not include renewable energy consumption so decrease is also an effect of switch to renewable energy sources in this sector

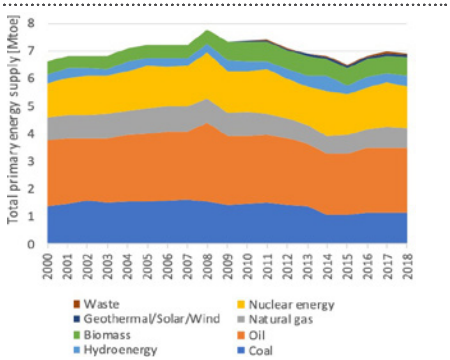
National energy supply

In 2018, Slovenia's Total Primary Energy Supply (TPES) reached 6.86 Mtoe. This was 0.9% lower than the previous year, and 5.7% higher than 2000. The highest TPES was reached in 2008 with 7.65 Mtoe. In the period 2000-2008 TPES on average grew by 2.1% per year, while in the period 2008-2018 primary energy decreased by 1.2% per year. Slovenia's GDP in the period 2000-2018 increased by 50.2%.

Oil products are a dominant energy source with a share of 34.0% in 2018, followed by nuclear energy and coal with 21.8% and 16.3%. Natural gas represented 10.5%. The share of all renewables was 16.5% increasing from 11.9% in 2000. The most important RES is biomass, followed by hydro energy.

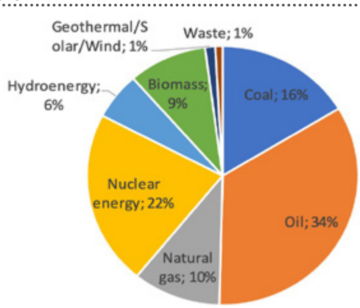
In 2019, no bigger changes were anticipated compared to 2018.

Figure 5.270 **Slovenia's total primary energy supply**[2]



Source: SORS

Figure 5.271 **Structure of total primary energy supply (2018)**

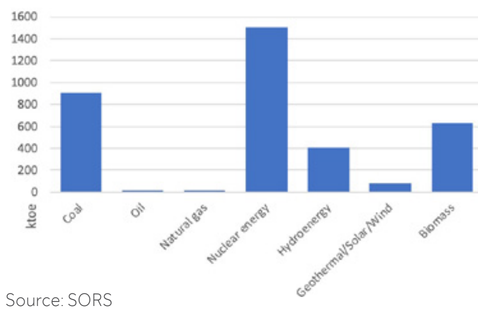


Source: SORS

Energy balance

Domestic production of primary energy in Slovenia increased between 2000 and 2011 from 3.25 Mtoe to 3.85 Mtoe and afterwards it decreased in 2012 to 3.59 Mtoe and remained at that level until 2018 (3.54 Mtoe). Also, its structure did not change significantly in the period 2000-2018. Nuclear is country's main source of indigenous energy, accounting for 42.5% in 2018. Coal represents 25.4% of domestic production, being decreased from 34.3% in 2000. Share of RES has increased from 24.3% to 31.7%.

Figure 5.272 **Domestic production of primary energy in 2018 in Slovenia (Total = 3,542 ktoe)**

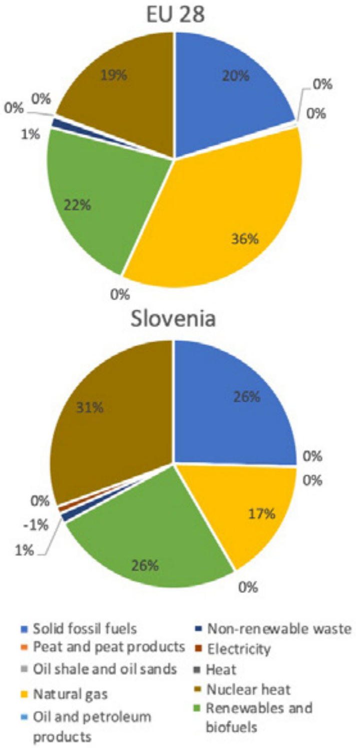


Source: SORS

Energy mix

The energy mix of Slovenia is roughly similar to the energy mix of EU 28. The majority of energy falls into four categories: natural gas, coal, nuclear and renewables, but there are large differences in their shares. For EU 28 the largest share falls to natural gas, while in Slovenia natural gas has the smallest share between the four largest categories. In Slovenia the largest share corresponds to nuclear, while in EU28 this category has the smallest share. Coal and renewables have higher share in Slovenian energy mix compared to EU28.

Figure 5.273 **Structure of Gross inland energy consumption in Slovenia and EU28 (2018)**



Source: EUROSTAT

The energy mix of final energy consumption is presented in the Table 5.231. In industry, electricity and natural gas are the dominant energy sources, in transport oil products are by far the most dominant source, in the residential sector the most dominant source are biofuels (wood biomass) while in other sectors electricity and oil products are the most dominant sources. Oil products are by far the most dominant source in total final energy consumption.

Table 5.231 **Energy mix per sector and of total final energy consumption (2018)**

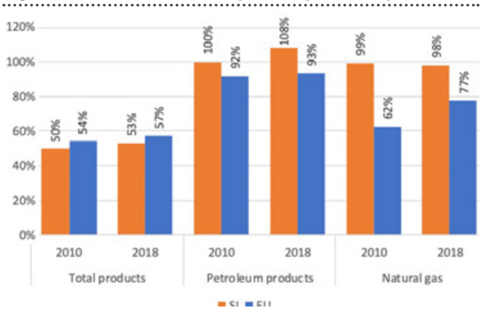
	Industry	Transport	Residential	Other	Total
Coal	38	0	0	0	38
Crude Oil	0	0	0	0	0
Oil Products	115	1.904	125	159	2.303
Natural Gas	465	3	111	18	597
Nuclear	0	0	0	0	0
Hydro	0	0	0	0	0
Geothermal, Solar, Wind	0	0	46	14	60
Biofuels & Waste	124	74	419	1	619
Electricity	589	20	290	282	1.180
Heat	50	0	75	50	175
Total	**1.381**	**2.001**	**1.066**	**524**	**4.972**

Source: SORS

Degree of energy dependence

Based on EUROSTAT data, Slovenia's import dependency in 2018 for all fuels was 53% and it was very close to EU 28's average import dependency of 57%. The lower import dependence of Slovenia is due to the higher share of nuclear energy and RES in TPES. On the other hand Slovenia has very high import dependency for petroleum products where it is completely import dependent and also for natural gas where the import dependency is also close to 100%. Petroleum products are imported from various countries but mostly from neighboring refineries in Austria, Croatia, Hungary and Italy. The energy trade deficit (mostly on oil) expressed in percentage of GDP is high and well above the EU average.

Figure 5.274 **Slovenia's import dependency**



Source: EUROSTAT

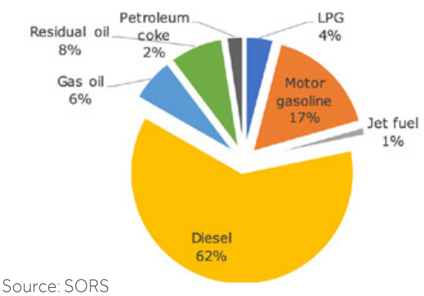
[2] Oil includes crude oil and oil products

Oil and Petroleum Products

(a) Oil supply and demand

Slovenia maintained a small production of crude oil. In 2018 it amounted to 0.9 ktoe, while there was no production of petroleum products. In 2018 primary supply with imported petroleum products amounted to 2.352 Mtoe, recording an increase of 0.4% compared to 2017. The highest level of consumption was achieved in 2008 with 2.879 Mtoe. The first data for 2019 is indicating a slow decrease in consumption. The most important petroleum product in Slovenia is diesel oil with a 62% share, mainly used in transport, followed by motor gasoline with 17% share, also mainly used in the transport sector. Transport is by far the highest user of petroleum products in Slovenia.

Figure 5.275 **Structure of oil demand in Slovenia for year 2018**



Source: SORS

Table 5.232 **Key oil data for Slovenia**

	2000	2008	2010	2015	2018
[Mtoe]					
Production	0.098	0.000	0.000	0.000	0.001
Demand	2.392	2.879	2.458	2.209	2.352
Motor gasoline	0.809	0.679	0.593	0.443	0.431
Gas/diesel oil	1.172	1.967	1.695	1.591	1.719
Residual oil	0.120	0.016	0.009	0.003	0.000
Others	0.291	0.217	0.162	0.172	0.202
Net import	2.332	2.995	2.491	2.261	2.548
%					
Import dependency	97%	104%	101%	102%	108%
Share in TPES	37%	38%	34%	34%	34%

Source: SORS

(b) Oil imports/dependence

There were no crude oil imports to Slovenia in the period 2010-2018. As was mentioned above, Slovenia imports all petroleum products that are consumed. In 2018 the import of petroleum products in Slovenia amounted to 4.664 Mtoe, while almost half of this (2.115 Mtoe) was exported to other countries, resulting in net import of 2.548 Mtoe, that is 8% more that the consumption (2.352 Mtoe).

(c) Upstream sector - domestic production and exploration

Slovenia is fully dependent on imports of all petroleum products and has no operating refineries. Petroleum products are usually imported from neighboring refineries in Italy, Croatia, Hungary or Austria.

(d) Downstream and midstream sectors infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

There are no operating oil pipelines in Slovenia and all petroleum products for commercial use are transported by conventional means of transport, such as road tracks and railways.

Most of the existing oil terminals in Slovenia are used for non-commercial purposes (i.e. compulsory and strategic reserves). There is only one major entry point for petroleum products in Slovenia. It is situated in the Port of Koper, known as the Instalacija Sermin (Sermin Installation) and it is operated by Petrol. According to the annual report of Petrol, in 2018 the Sermin Installation reached a record volume of petroleum products. Sermin Installation storage facilities are designed for the storage of diesel, petrol and extra light fuel oil, as well as storage of biodiesel and additives dedicated to improve the quality of petroleum fuels. The Installation has 480,000 m3 of reservoir capacity in 23 tanks, a tanker pier, a truck and wagon filling station and all associated infrastructure for the storage and handling of petroleum products.

The major players in the Slovenian market of petroleum products are Petrol d.d., OMV Slovenija d.o.o. and MOL Slovenija d.o.o.

(e) Security of supply

According to the Slovenian oil stockpiling policy, the maintenance of emergency oil stocks is delegated to the state-owned Agency of the Republic of Slovenia for Commodity Reserves (ZRSBR). Over the years, the Agency for Commodity Reserves has created a stable portfolio of time-tested operators of storage facilities (so called tank farms) for petroleum products located across Slovenia's borders and the Agency is successfully maintaining the mandatory level of compulsory stocks according to the Council Directive 2009/119/EC. The Agency's obligation has been determined as «a minimum daily average net import for 90 days» compared to previous year consumption. The level of emergency stocks has to be adjusted until March 31st every calendar year (until that date, the stocks may correspond the country's stockholding obligation of two years before). According to the Agency's Annual report for 2017[3], at December 31st 2017, the Agency had at its disposal 603,369 tons of petroleum products that were equivalent to emergency stocks lasting 94.83 days. Of this quantity, the stocks owned by the Agency for Commodity Reserves were around 522,369 tons or 87% and the delegated stocks (cross border tickets) totaled 81,000 tons or 13%. Also, 67.6% of stocks were stored within the territory of the Republic of Slovenia and 32.4% were stored abroad (cross border stocks in Germany, Hungary, Italy, the Netherlands and Slovakia).

(f) Planned new projects

There are no new planned oil projects in Slovenia.

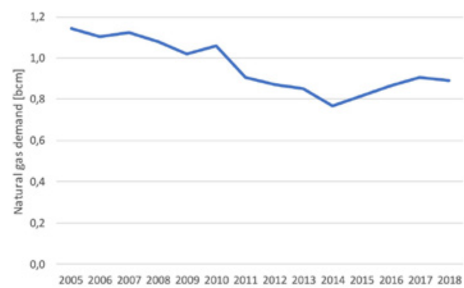
Natural Gas

(a) NG Supply and Demand (in bcm)

Domestic production of natural gas in Slovenia is very small although it increased in 2017 and 2018, amounting 0.016 bcm in 2018, being several times higher than in 2015. Production takes place in the North-Eastern part of Slovenia.

National gas demand has been decreasing from 2005 reaching minimum demand in 2014 amounting to 0.77 bcm (see Fig. 12). In the period 2015-2017 demand increased, reaching 0.91 in 2017. In 2018 a slight decrease has been observed resulting in consumption of 0.89 bcm. First data for 2019 are indicating a small increase in consumption (0.5%).

Figure 5.276 **Natural gas demand for Slovenia (2005-2018)**



Source: SORS

Table 5.233 **Key Natural gas data in Slovenia**

	2000	2005	2010	2015	2017	2018	2019*
[mcm]							
Production	7	4	7	3	8	16	
Demand	1.014	1.141	1.059	816	907	890	895
Trans-formation	164	165	193	121	150	148	
Industry	604	665	593	494	539	572	
Residential	72	121	140	127	146	136	
Other sectors	174	191	134	74	72	34	
Net imports	1.007	1.137	1.053	813	899	874	
%							
Import dependency	99%	100%	99%	100%	99%	98%	
Natural gas in TPES	13%	13%	12%	10%	11%	11%	

Source: SORS

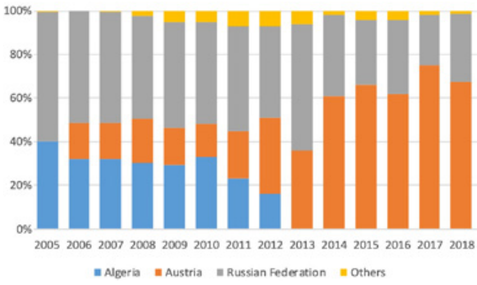
(b) NG Imports (in bcm)

In 2018 Slovenia imported gas from Austria, Russia and Italy. 70% has been purchased from Austria, while the majority of the rest from Russia and just 0.5% from Italy. In the period from 2014 to 2018 the majority of natural gas came from Austria, while in the past Italy (natural gas of

[3] https://www.dbr.si/wp-content/uploads/2018/04/Letno-porocilo-ZRSBR-2017-sprejeto-na-Vladi.pdf

Algerian origin) was another important source country. However, it is important to mention that natural gas from Austria is mainly originating from Russia.

Figure 5.277 **Natural gas imports in Slovenia by Country of Origin**

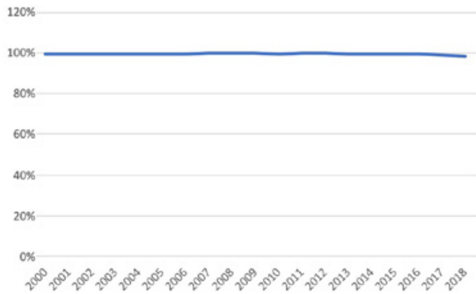


Source: SORS

(c) Natural gas dependence (%)

Since Slovenia has a very small production of natural gas, it is almost fully dependent on imports to cover its demand (Table 5.233, Figure 5.278).

Figure 5.278 **Natural gas dependency of Slovenia**



Source: SORS

(d) Domestic Production and Exploration

Domestic production in 2018 amounted to 0.016 bcm representing 1.8% of Slovenia's demand. Exploration of natural gas in Slovenia is ongoing in just one location in the North-Eastern part of Slovenia, in a reservoir known as "Petišovci globoko". Exploration of natural gas began in 1943, and from 1963 until 2017 some 342 mcm of natural gas had been extracted. Peak production was reached in 1989, when more than 33 mcm was produced.

Company Geoenergo d.o.o., which is a subsidiary of Slovenian oil company Petrol, is the holder of an exploitation concession contract for this field since 2002, giving it the exclusive right for oil and gas exploitation and production in this area until 2022. The project of natural gas production is a joint venture of Geoenergo d.o.o. and Ascent Resources, being undertaken by Ascent Slovenia Limited, the project manager. In 2017 a contract with the Croatian oil and gas company INA was signed for delivery of raw natural gas to the Molve processing facility, since they were not able to obtain a permit for the construction of a natural gas processing facility in Slovenia.

Geoenergo and Ascent are facing strong opposition for this project from environmental organizations. The latest decision of the Slovenian Environmental Agency, that a separate permit for hydraulic fracturing is needed, has once again delayed production. Ascent Resources plans to take a multi-pronged legal action against Slovenia because of this creating further delay for the implementation of the project.

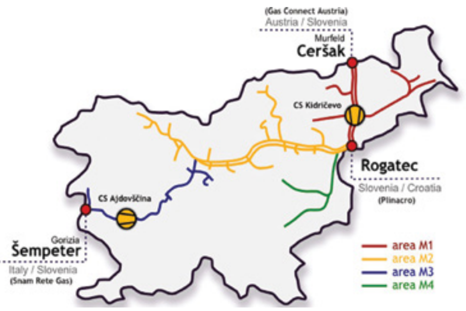
Exploration of natural gas is regulated by the Mining Act (Official Gazette of the Republic of Slovenia No. 14/2014).

(e) Infrastructure (Pipelines, Storage)

In 2018 the Slovenian transmission system consisted of 946 km of pipelines with nominal pressure of more than 16 bars and 211 kilometers of pipelines with nominal pressure below 16 bars. The transmission system operator (TSO), company Plinovodi, also controlled 203 metering-regulation stations, 44 metering stations, seven reducing stations and two compression stations in Kidričevo and Ajdovščina. The transmission system is connected with the neighboring system in Austria at point Ceršak, with Italy at point Šempeter pri Gorici and Croatia at point Rogatec. At the border point with Italy bidirectional flow is possible, at the border point with Austria flow from Austria to Slovenia is possible and at the border point with Croatia from 2019 onward bidirectional flow is possible. In the short term future additional expansion of the network is foreseen, connecting the southwest region to natural gas network and enabling the use of natural gas for electricity and heat production in Ljubljana.

In the period between 2016 and 2018 the daily technical utilization at exit points did not change. The largest daily capacity was at point Ceršak (import 76 GWh), followed by point Rogatec (export 43 GWh/import 7 GWh) and Šempeter (import 27 GWh/export 13 GWh). At all points the transmitted amount of gas decreased in 2018 compared to previous years. The largest daily utilization of the transmission network in 2018 occurred on 28th of February with 2,427,255 kWh/h not reaching contract or physical congestion.

Map 5.69 **Typology of Slovenian transmission system with relevant points**



Source: Plinovodi

Slovenia's distribution network in 2018 consisted of 4.827 kilometers of pipelines, increasing by 1.8% compared to previous years

LNG terminals

In the past there were talks of an LNG terminal to be constructed in Slovenia, but environmental concerns stopped the plans.

Currently the nearest location for an LNG terminal is on the island Krk, in Croatia. The project has received backing and financial support from the European Commission. Technical capacity of floating terminal will depend on the technical characteristics of the terminal, while the maximum annual delivery of natural gas is expected to be 2.6 billion cubic meters in the first stage of the project. The maximum annual delivery of natural gas will depend on the future pipeline development. The project is planned to receive their first batches of gas in 2020.

Storage

In Slovenia there are no underground gas storage facilities. There are also no plans to construct any storage facility in the future. Good connections to European gas network system enable Slovenia to have high security of natural gas supply. The nearest underground gas storage is in Austria with capacity of more than 4.7 bcm, while Slovenia consumes 0.8 bcm per year.

(f) Domestic Gas Market

Slovenian wholesale natural gas market is determined by imports of gas through neighboring transmission systems (Austria, Italy and Croatia). Slovenian natural gas market is open and fully liberalized. Market transparency is ensured by preventing market manipulation and trading on the basis of inside information, a requirement for effective and timely disclosure of inside information, and appropriate legislative framework for market monitoring. In this context the Slovenian Energy Agency, as the market regulator, plays key role.

Interconnector Slovenia - Hungary has been recognized as a "Project of Common Interest (PCI) – 2017" and has been included in a list of projects of Central and South Eastern Europe Connectivity and the Three Seas Initiative. The project for the interconnection between the Hungarian and Slovenian transmission system, as it is reported and described with the PCI status, will enable the bidirectional gas route between Italy - Slovenia - Hungary.

The majority of natural gas consumed in Slovenia is being imported through the interconnection with Austria, where at the gas hub Baumgartner and Austrian storages Slovenian energy traders buy most of the natural gas for the domestic market. In 2018 70% of all gas imports in Slovenia came through the interconnection with Austria. As a result of market liberalization there is a trend in decreasing the number of long-term contracts signed directly with natural gas producers in Russia. According to the Slovenian Energy Agency, in 2018 61.2% of natural gas was purchased on the basis of short-term contracts while the remaining 38.8% was purchased on the basis of long-term ones.

The major players in the Slovenian wholesale natural gas market are listed in Table 5.234. Also, this table contains the so called Herfindahl-Hirschman index (HHI) of the Slovenian wholesale market. The HHI index is calculated by squaring the market share of each company competing in a market and then summing up the resulting numbers. The Slovenian Energy Agency, as the regulator of the energy market, uses this index to determine if the natural gas industry should be considered competitive or is closer to being a monopoly. According to the Energy Agency, natural gas market concentration measured by HHI shows a very high degree of concentration on the Slovenian wholesale market. The HHI value strongly exceeds the limit, which is a boundary between middle and high concentration level.

Table 5.234 **Market shares and the HHI of the natural gas wholesale market in 2018**

Name of company	Market share
Geoplin	80.33%
Petrol	15.57%
Plinarna Maribor	2.71%
GEN-I	1.31%
Adriaplin	0.09%
Total	100%
HHI of the wholesale market	6,704

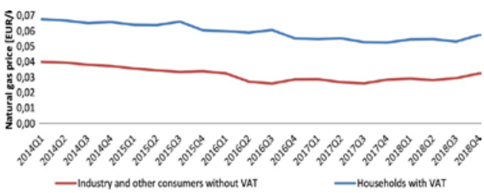
Source: Slovenian Energy Agency

Traditionally, the largest market share in the Slovenian wholesale market belongs to the "Geoplin Company", Ljubljana, which in 2018 had a market share of 80.3%. The second largest market player is the "Petrol Company", which in 2018 had a market share of 15.6%. "Petrol" is also the largest trader and distributer of petroleum products in Slovenia.

In 2018, 23 natural gas suppliers (five less than in 2017) were active in the Slovenian retail market, which according to contracts supplied natural gas to 134,642 consumers (1,312 more than in 2017). Reduction in the number of active natural gas suppliers is the result of merges and acquisitions but also it has to be emphasized that two suppliers left the retail market in 2019. Final consumers can change their supplier at any time. Also, suppliers must publish on their websites offers for household and small business consumers. In 2017 prices reached their lowest level since 2011. In 2018 this trend changed somewhat for certain groups of consumers. However, average prices remained almost unchanged. Compared with neighboring countries, natural gas prices for typical household consumer in Slovenia in 2018 (final prices including all taxes and levies) were lower than in Austria and Italy but higher than in Croatia and Hungary. Also, in 2018 natural gas prices for typical household consumers in Slovenia remained below the EU-28 average. On the other hand final natural gas prices including all taxes and levies for typical industrial consumers in Slovenia in 2018 were higher than in all neighboring countries and remained above the EU-28 average.

The development of natural gas prices in Slovenia since 2014 is shown in Figure 5.279.

Figure 5.279 **Development of natural gas prices in Slovenia**



Source: SORS and Ministry of Infrastructure

(g) National NG policy - strategic plan

According to new Slovenian NECP, national gas is considered as an important transition fuel towards a climate neutral society. Slovenia has already established a favorable legislative framework for electricity production in natural gas fired high efficient cogeneration units.

Additionally, Slovenia has a favorable geographical position in relation to the flow of natural gas in Europe due to its close proximity to the transmission routes from Eastern Europe (from Russia through Slovakia and Austria towards Italy and Croatia) and its border with Italy, where the transmission routes from the Mediterranean Basin and Northern Europe converge. NECP includes concrete measures for the promotion of research cooperation and support mechanisms for joint development projects between companies from different energy sectors, namely electricity, natural gas and district heating. Slovenia is planning different projects to increase the operational security and expansion of its transmission system. In this context NECP, supports the implementation of pilot projects for the production of synthetic methane and hydrogen (indicative target of 10% share of methane or hydrogen of renewable origin in the natural gas transmission and distribution network by 2030).

The future development of the transmission system is in line with the expected physical flows of natural gas and system capacities, including new sources of synthetic gas. In coming years Slovenia will prepare a regulatory and support environment for renewable gas alternatives and based on results of pilot projects, it will determine the maximum hydrogen content in the existing network.

(h) Planned new projects

According to currently valid ten-year gas transmission network development plan for the 2019 - 2028, Slovenia is planning several projects that will increase operational security and support expansion of its transmission network. Additionally, several projects for connecting new natural gas consumers or changing the operational characteristics of gas infrastructure, and projects for developing interconnection points are also envisioned. In this context, expansion of the transmission system includes system pipelines, energy loops, displacements of pipeline sections due to specific settlement modifications, and prevention of landslides.

A previously mentioned new project between Hungary and Slovenia will enable the establishment of natural gas flows between Italy and Hungary via Slovenia, and thus the direct interconnection between these three gas markets. The project will also connect the currently unconnected Slovenian and Hungarian transmission system. Additionally, a group of projects in the corridor of Austria, via Slovenia, towards Croatia have a PCI status. This represents an upgrade of the capacity of existing transmission systems and the establishment of reverse flows between the systems in those three counties.

It is also worth mentioning the upgrade of the District Heating System in the Slovenian capital Ljubljana, which includes replacement of two coal fired cogeneration units at the Thermal Power Plant Ljubljana (TE-TOL) with new natural gas fired combined heat and power plant with total electrical power output of 142 MW. It is expected that this new unit will commence operation by the end of 2021 or at the beginning of 2022 and it will enable significant reduction of GHG emissions in Ljubljana.

Solid Fuels

(a) Supply and consumption

The supply of solid fuels in Slovenia in 2018 amounted to 1.13 Mtoe, a decrease of 1.0% compared to 2017. The majority of solid fuels was used for the production of electricity and heat with 1.08 Mtoe in 2018, while total final consumption including non-energy use amounted to 46 ktoe.

The main solid fuel used in Slovenia is domestic lignite, that is used in the Šoštanj power plant. In 2018 this fuel represented 81% of total solid fuel consumption. Approximately 17% of solid fuels is imported brown coal mainly used in Ljubljana CHP plant, while the rest is coke and anthracite used in industry.

Table 5.235 **Key Solid fuels data in Slovenia**

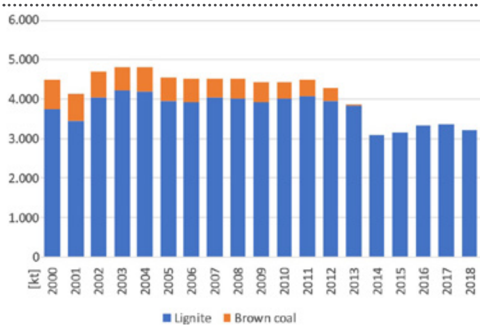
	2000	2005	2010	2015	2017	2018	2019*
ktoe]							
Production	1,115	1,173	1,196	862	933	901	
Demand	1,358	1,532	1,455	1,068	1,141	1,129	1,050
Trans-formation	1,278	1,426	1,402	1,022	1,095	1,083	
Industry	76	80	47	39	38	38	
Residential	5	0	1	0	0	0	
Other sectors	0	26	5	7	8	8	
Net imports	243	329	280	204	198	211	
[%]							
Import dependency	18%	21%	19%	19%	17%	19%	
Solid fuels in TPES	21%	21%	20%	16%	16%	16%	

* 2019 data are estimates
Source: SORS

(b)Local production and exploration

Currently only lignite is produced in Slovenia. In 2018 production accounted at 3.22 Mt, 4.1% less than the year before. Compared to 2000, lignite production decreased by 14%, while brown coal production that was present in 2000 ceased in 2013 with the closure of Termoelektrarna Trbovlje (Thermal Power Plant Trbovlj). Domestic lignite is exploited at the Velenje Coal Mine and all of its output is used at the nearby Šoštanj power plant. It is operated by the Premogovnik Velenje company, which belongs to Holding Slovenske Elektrarne (HSE) together with an underground mine. NECP foresees that coal use for electricity production will decrease by 30% until 2030, having an effect also on domestic production.

Figure 5.280 **Domestic production of solid fuels in Slovenia in the period 2000-2018**



Source: SORS

(c) Deposits

According to Euracol, lignite and brown coal resources in Slovenia are estimated to be 1.256 million tons, located at Velenje (358 million tons), Zasavje (68 million tons) and Goričko (830 million tons), with mineable reserves accounting for 109 million tons.

(d) Coal imports

The majority of solid fuels in the form of thermal coal, that were imported in Slovenia in 2018, corresponding to 80% of total consumption, were used for heat and electricity production in the Termoelektrarna Toplarna Ljubljana Power Station (TE-TOL). The remaining amount was used in the following industrial branches: Manufacture of paper and paper products (13%) and manufacture of other non-metallic mineral products (7%). Domestic indigenous lignite production accounted for approximately 13.1% of primary energy supply in 2018, with imported coal bringing coal's total share to 16.3%. According to NECP, by 2030 Slovenia will abandon the use of imported coal to produce heat and electricity in TE-TOL and any other use in industry.

(e) Planned new projects

Current energy policy foresees the use of coal only in existing installations and until the end of their operational life. According to NECP, Slovenia is planning its coal phase-out strategy which will include all the necessary legislation regarding the gradual closure of the existing Velenje Coal Mine and the restructuring of the coal regions based on just transition principles (Zasavje in Šaleška region).

Electricity

(a)Electricity supply and demand (in TWh)

Gross electricity production in 2018 amounted to 16.33 TWh, up by 20% compared to 2000 or 2.71 TWh. The largest increase in electricity production in the 2000-2018 period came from hydropower plants with 1.06 TWh closely followed by nuclear electricity from the Krško plant with 1.02 TWh. Some 0.37 TWh of electricity increase came from thermal power plants and the rest from photovoltaic plants (0.26 TWh) and wind farms (6 GWh).

The structure of electricity production has slightly changed since 2000, by reducing the share of electricity from thermal power plants, from 37% in 2000 to 33% in 2018, while the share of hydro power plants increased from 28% to 30% and the share of photovoltaic plants increased from 0% to 2%.

In 2018 the total electricity consumption in Slovenia amounted to 13.82 TWh, excluding losses in the distribution and transmission network. Compared to the previous year consumption increased by 1.4% and compared to 2000 it increased by 29.6%. Approximately, 50% of electricity is consumed by industry, with business, direct and closed distribution systems (connected to the transmission network) having consumed 2.08 TWh. Households and the service sector each correspond to 24% of total final electricity consumption. The transport sector represented 2% of electricity use and the energy sector 1%. The hydroelectric pumped-storage power plant at Avče used 252 GWh. Electricity losses in the transmission and distribution networks amounted to 880 GWh. Own use of power plants amounted to 877 GWh.

Electricity consumption in Slovenia, taking into account half of the production from the Krško Nuclear Power Plant (NPP) (since the other half of the plant is owned by Croatia), and own use and loses, was not completely covered with domestic production, reaching 84% in 2018. The lowest consumption share produced by domestic production was reached in 2003 and 2007 at 76%.

(b) Installed Capacity

In 2018, Slovenia's total installed electricity capacity was 3.80 GW and its breakdown is shown in Table 5.236. The largest installed capacity belongs to thermal power plants with 1.54 GW, followed by hydro power plants with 1.34 GW, including pumping-storage facility. Table 5.235 shows the breakdown of installed electricity capacity in Slovenia. Compared to 2005 the largest growth in capacity has been observed in hydro power plants followed by photovoltaics and wind and thermal power plants. Electricity production on photovoltaic and wind power plants increased much less than their installed capacity due to smaller operating hours (approximately by a factor of 4).

Table 5.236 **Yearly electricity production and consumption in Slovenia**

		2000	2005	2010	2015	2017	2018	2019
Gross electricity production	[GWh]	13.624	15.117	16.440	15.100	16.326	16.331	15.807
Hydropower plants	[GWh]	3.834	3.461	4.703	4.091	4.141	4.893	
Thermal power plants	[GWh]	5.029	5.772	6.067	5.081	5.610	5.400	
Nuclear power plant	[GWh]	4.761	5.884	5.657	5.648	6.285	5.776	
Photovoltaic plants	[GWh]	-	0	13	274	284	255	
Wind power plants	[GWh]	-	-	-	6	6	6	
Loses and use for pumping	[GWh]	811	952	1.227	1.244	1.259	1.132	
Own use	[GWh]	829	968	1.030	913	929	877	
Net import	[GWh]	-1.321	-325	-2.120	-48	-516	-502	
Final consumption	[GWh]	10.664	12.872	12.063	12.895	13.623	13.819	
Energy sector	[GWh]	142	129	118	107	93	96	
Industry	[GWh]	5.490	7.172	5.487	6.199	6.446	6.847	
Transport	[GWh]		265	197	173	152	233	233
Households	[GWh]		2.601	2.951	3.219	3.205	3.327	3.368
Services	[GWh]		2.166	2.423	3.066	3.232	3.524	3.275

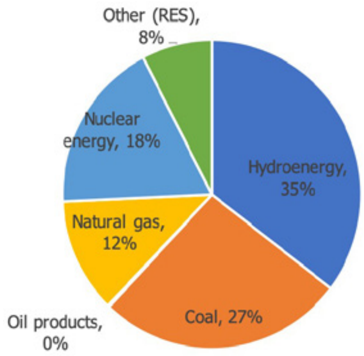
Source: SORS

Table 5.237 **Breakdown of installed gross electricity capacity (MW) in Slovenia**

		2005	2010	2018
Hydro power plants	[MW]	979	1254	1343
Thermal power plants	[MW]	1356	1261	1540
Nuclear power plants	[MW]	656	666	688
Photovoltaics and wind	[MW]	0	12	227
Total gross installed capacity	[MW]	2991	3193	3798

Source: SORS

Figure 5.281 **Installed capacity (MW) per fuel type (2018)**

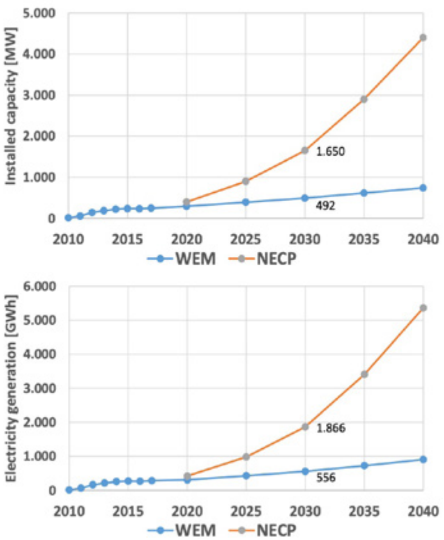


Source: SORS

(c) Planned new capacity – investments

According to NECP, up to 2030 the majority of new capacity is planned in decentralized RES electricity generation. Electricity generation in solar photovoltaic plants (PV) represents the largest single development which is environmentally acceptable, in terms of new potential for increased electricity production from RES in Slovenia. Considering sustainability and spatial planning principles, integration of PV modules into buildings will be prioritized. The technical potential in terms of available areas for electricity generation from PV is estimated at more than 20 TWh/year. However, the key limitation is the ability of the existing electricity distribution network to absorb new capacities which also influence the economics of new projects. Estimated development of electricity generation from PV up to 2040 is shown in Figure 5.282, where the blue line represents existing situation and future development in a scenario with existing measures (WEM) and the orange line depicts expected development according to the NECP scenario.

Figure 5.282 **Expected future development of electricity generation from solar PV in Slovenia**

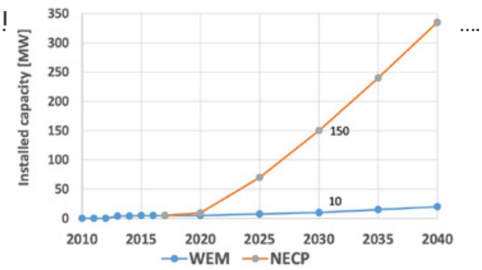


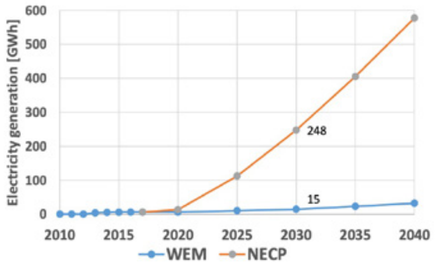
Source: NECP

Regarding the large hydro power plants, the NECP up to 2030 foresees the finalization of HPP Mokrice on Sava River, but only in case that environmental acceptance is achieved. Or in the case that additional measures will be required to ensure coordination and implementation of procedures for overriding public interest for the project (reaching goals of RES in final energy consumption and reduction of GHG emissions over protection of water and nature).

In the field of wind energy Slovenia is facing a similar situation since a significant part of the non-governmental sector and the public strongly opposes any further construction of wind farms. Therefore, in the various scenarios for wind power development NECP foresees that reaching 150 MW of installed capacity up to 2030 will be very challenging for Slovenia. Estimated wind power development up to 2040 is shown in Figure 5.283.

Figure 5.283 **Expected future development of wind**





Source: NECP

As it has already been stated, the upgrade of the district heating system in Ljubljana, includes the replacement of two coal fired cogeneration units at TE-TOL with new natural gas fired combined heat and power plant with total electrical installed capacity of 142 MW. It is expected that this new unit will start operation by the end of 2021 or at the beginning of 2022 and that will enable a significant reduction of GHG emissions in Ljubljana.

Regarding the future use of nuclear power, NECP foresees life extension of the existing Krško NPP. Concerning the construction of a new unit the NECP proposes that a decision about the long-term use of nuclear energy should be taken by 2027. This decision must be based on a comprehensive analysis and should provide the answer about costs and benefits of the potential construction of a new unit in Krško.

The Slovenian transmission and distribution system operators are obliged to prepare 10-year development plans every two years; plans are evaluated and approved by the ministry responsible for energy. In the context of the new NECP, both operators will have to prepare new development plans within nine months after the adoption of the NECP and obtain approval by the ministry responsible for energy. Development plans must cover a period of at least ten years and must be consistent with instruments and measures proposed by NECP. Both plans must consider the strategic national energy policy goals and must be harmonized with each other. Additionally, the physical and financial extent of necessary investments in new facilities must be determined, as well as investments for the renovation and upgrade of existing electricity infrastructure facilities in the transmission and distribution network.

(d) Electricity imports – exports

According to the Energy Agency's annual report, in 2018 some 15,003 GWh of electricity was delivered to the Slovenian transmission and distribution system, which was 19 GWh more than in 2017. The delivery from power plants using RES was 5,177 GWh, which is 698 GWh more than the year before. Power plants using fossil fuels contributed 4,343 GWh or 196 GWh less than in 2017. Due to scheduled maintenance at Krško NPP in 2018, it delivered 5,483 GWh of electricity or 483 GWh less than the year before (2017 was the year without scheduled maintenance works). In 2018 through the transmission and distribution networks, 9,317 GWh of electricity was exported (241 GWh less than the year before), and 8,930 GWh of electricity was imported (203 GWh less than the year before), as shown in Tables 5.238 and 5.239.

Table 5.238 **Net electricity generation and imports in GWh (2018)**

	Volume in GWh
Hydropower plants (large)	4,421
Thermal power plants	4,049
Nuclear power plant	5,483
Small producers (including small CHP units using fossil fuels)	1,050
Total electricity production in Slovenia	15,003
Imports	8,930
Total	23,933

Source: Energy Agency

Table 5.239 **Electricity consumption and exports in GWh (2018)**

	Volume in GWh
Business consumption from the transmission system	208
Business consumption from the distribution system	8,006
Business consumption from the closed distribution systems	1,902
Total business consumption	10,116
Household consumption – single-tariff metering	888
Household consumption – two-tariff metering	2,480
Total household consumption	3,368
Consumption of pumping hydropower plant Avče	252
Total consumption of end consumers	13,736
Transmission and distribution systems losses	880
Total consumption of electricity	14,616
Exports	9,317
Total	23,933

Source: Energy Agency

(e) Tariffs

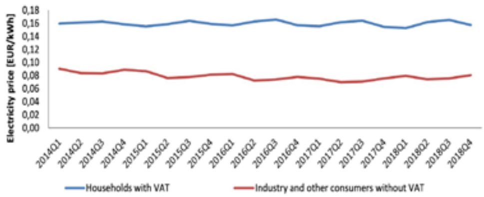
Slovenia has a well-diversified energy mix and hence highly competitive wholesale and retail electricity markets. The Energy Agency monitors the level of wholesale prices in Slovenia and in related markets that affect prices in Slovenia. Also, it regularly monitors the prices in the household and business markets as it receives from the suppliers monthly information on price changes or supply offers in the retail market.

In the retail market, suppliers and traders sign open contracts, in which the quantities of supplied electricity and the time profile of supply are not set in advance. Consumers pay for the supplied electricity according to actual consumption metered by the utility meters. Some 13,879 GWh[4] of electricity, 2.3% more than the year before, was delivered to all consumers in Slovenia in 2018. In the retail market 23 electricity suppliers were active in 2018 and 17 of them supplied household consumers. The final electricity price for consumers in Slovenia consists of:

- the wholesale electricity price which is formed freely in the market, on a daily basis,
- the network charge (it varies regarding voltage supply level and includes charge for the transmission and distribution network - consumers directly connected on transmission network don't pay charges for distribution network),
- levies (for supporting electricity production from RES and CHP, supporting energy efficiency programs and for the operation of the market operator),
- excise duty and
- value added tax (VAT).

The development of electricity prices in Slovenia since 2014 is shown in Figure 5.284.

Figure 5.284 **Development of electricity prices in Slovenia (source SORS and Ministry of Infrastructure)**



Source: SORS and Ministry of Infrastructure

(f) Cross-border interconnections

Slovenia enjoys a high level of electricity interconnectivity with neighboring countries that will be further strengthened in the coming years. In 2017 the level of electricity interconnectivity was 83.6% and well above the EU average. However, the new NECP foresees additional measures and policy instruments for enhancing interconnectivity with neighboring countries (Hungary and Croatia), diversification, auxiliary services, flexibility, energy storage, etc. According to the World Energy Council, Slovenia is one of the strongest Energy Trilemma performers, ranking 12th globally. According to ENTSO-E calculations, Slovenia is expected to retain its transit status in future and will foreseeably be even more exposed to cross-border power flows in all directions, particularly at the borders with Austria and Italy. A vision of the long-term development of the Slovenian transmission network is shown in Figure 5.285.

[4] According to Annual report on the energy sector in Slovenia for 2018 (Slovenian Energy Agency)

Map 5.70 **Vision of long-term development of the Slovenian transmission network**

Source: ELES

The Slovenian power system is interconnected with 3 neighboring power systems:

- Austria (2x400 kV Maribor-Kainachtal and 220 kV Podlog-Na Selu (Obersielach)),
- Croatia (2x400 kV Krško-Tumbri and DV 400 kV Divača-Melina, 220 kV Cirkovce-Žerjavinec and DV 220 Divača-Pehlin, 110 kV Koper-Buje, 110 kV Ilirska Bistrica-Matulji and 110 kV Formin-Nedeljanec),
- Italy (400 kV Divača-Sredipolje (Redipuglia)) and 220 kV Divača-Padriče (Padriciano)).

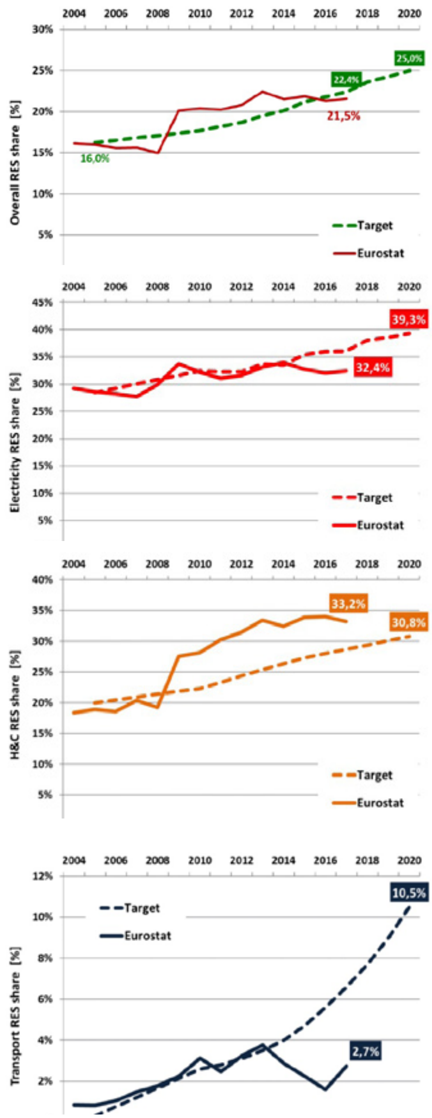
The double circuit overhead line of 400 kV Cirkovce–Pince (new interconnection between Slovenia and Hungary/Croatia) is the on-going EU project of common interest that should enable cross-border interconnection with Hungarian transmission system. Even though this project has faced many difficulties due to long lasting spatial planning procedures it is expected that it will be completed by 2021.

Renewables

(a) Overview of the sector's development

In 2018, Slovenia covered 21.1% of its gross final energy demand with renewable energy sources. This represented a slight decline of 0.5% from the previous year. Compared to 2005 the share increased by 32.1%, but largely this increase happened in 2009 and was to a large degree due to an improvement of RES statistics in households. In the period between 2009 and 2018 the RES share increased by only 4.9%. In this context Slovenia will face difficulties in reaching the 25% target set for 2020.

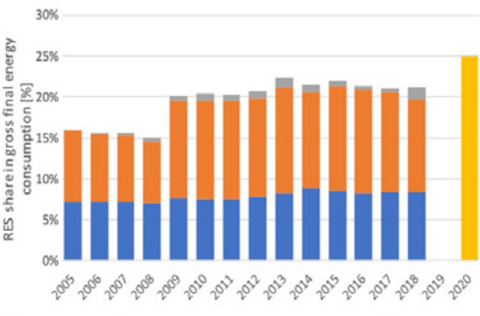
Figure 5.285 **Past trends in the development of RES share in gross final energy consumption (overall and sectorial) compared to target trajectories**



Source: SORS and NECP

The largest contribution to RES share comes from the heating and cooling sector. In 2018 its share in the total RES use was 54%. The main RES fuel in this sector is wood, which is widely used in households. Wood use in households contributes 71% to RES use in heating and cooling, while total RES use in households consumption contributes almost 80%. Electricity from RES contributes 40% to total renewable energy. RES use in electricity production is dominated by hydro energy with 90% share. Liquid biofuels in the transport sector contribute 7%. However, Slovenia's RES share is not increasing due to changes in gross final energy consumption. Compared to 2009 electricity use and energy use in transport increased. Especially energy use in transport is problematic, since the transport sector has a low share of RES. On the other hand, energy use for heating and cooling decreased, most significantly in households, where the RES share is the highest, to a large extent due to implemented energy efficiency measures.

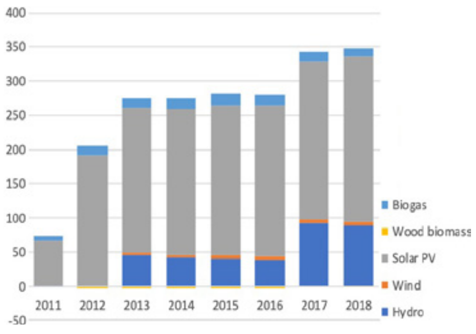
Figure 5.286 **RES share in gross final energy consumption**



Source: SORS

Installed capacity for RES use in electricity production increased in the period 2010-2018 by almost 350 MW. Between 2010 and 2013 a large increase in solar PV capacity has been observed, resulting in 262 MW of extra installed capacity in 2018, compared to 49 MW in 2010. However, it should be noted that between 2013 and 2018 the installed capacity in solar PV increased only by 28 MW, due to changes in the support scheme for RES electricity (i.e. tenders, lower support premium). The second largest increase was observed in hydro power, with 116 MW of new installed capacity in the period 2010-2018. An increase has also been observed in biogas capacity (13 MW) and wind (5 MW).

Figure 5.287 **Development in installed capacity for RES electricity in the period 2010-2018**



Source: SORS, Energy Agency

Slovenia has already exploited the majority of its environmentally acceptable hydro potential. Since 2006 a series of new hydro power plants in the lower part of Sava river have been built but the last one still remains incomplete, due to a lawsuit by environmental groups.

There are plans to build additional hydro power plants in the middle part of the Sava river, but there are once again disputes regarding environmental protection and so a comprehensive environmental impact assessment will have to be undertaken.

In the heating and cooling sector the largest potential lies with wood biomass, since almost 60% of Slovenia's territory is covered by forests, and also geothermal or ambient heat. Wood biomass is problematic from an air quality point of view, since individual boilers are the largest source of PM emissions. Biomass use in households has been declining due to energy efficiency measures (insulation of buildings and substitution of old boilers). It is promising that during recent years heat pumps are also gaining market share in the heating and cooling sector.

In the transport sector biofuels are blended with fossil fuels. Use of biofuels had been increasing until 2013, when a drop was observed, due to the elimination of tax breaks. In 2018 the use of biofuels again increased, but the share of biofuels in the transport sector is still below the technically allowed share of 7% for diesel and 5% for gasoline.

(b) Latest legislation, incentives and national RES policy

The Energy Act sets out the legal framework for supporting RES in Slovenia and fully implements RES directive 2009/28/EC. The new RES directive 2018/2001/EU has to be transposed by 30 June 2021.

Slovenia's RES target share in final energy consumption for 2020 is 25% and for transport 10%. The main policy document is the National Renewable Action Plan, that has been in place since 2010. The sectoral target for electricity has been set at 39.3% and for heating and cooling at 30.3%. Slovenia will have difficulty reaching its national target in 2020. The recently adopted NECP sets targets for 2030 and RES share in final energy consumption must be at least 27%. The target for electricity is 43%, for heating and cooling 41% and transport 21%. A necessary prerequisite for reaching the targets is the intensive implementation of energy efficiency measures while increasing the use of RES.

Electricity production from renewable sources in Slovenia is supported through a support scheme for electricity produced from renewable sources and with high-efficiency cogeneration. A support scheme was first introduced in 2009 and overhauled in 2014. After 2014 financial quotas are determined each year which are offered on tender and the cheapest units are selected. Support is available as guaranteed purchases of electricity (only for units of up to 500 kW) or financial aid for current operation (operating support). The duration of support for new RES generating units is 15 years. Units with nominal power up to 10 MW are eligible, only for wind units up to 50 MW. In 2019 the support scheme was prolonged until the end of 2025. Under the new scheme 5 public tenders (between 2016 and 2019) have been conducted corresponding to 50 million EUR and 285 projects have been chosen with electric power totaling 325.9 MW (RES electricity and CHP units). The largest share falls on wind energy with 215 MW, followed by solar PV with 23.6 MW and small hydro with 14.9 MW. The chosen projects have to be implemented within 3 or maximum 5 years. Due to difficulties in finding appropriate locations and receiving the needed allowances for wind energy it is not very likely that all wind energy projects will be built, meaning that funds have been allocated to projects that will not deliver much needed energy from RES. The consequence of this is that such schemes have much lower effect than it was originally anticipated. Household solar PV units are supported through the promotion of self-supply, while larger units with biomass, solar PV, wind and small hydro are supported through subsidies provided by the Ministry under cohesion policy support.

RES heat in households and public sector is supported through grants given by Ecofund. Funds are available for the installation of heat pumps, wood boilers, solar collectors and higher grants are available for substation of old wood boilers with new boiler or heat pumps, due to air quality problems. New buildings have an obligation regarding the share of energy originating from RES. District heat systems have an obligation regarding their share of heat that has to be produced from RES or by high efficiency CHP. Grants provided by the Ministry and Ecofund are also available for public buildings to install RES for heating. NECP sets 2023 as the date from which the sale of light fuel oil boilers will be banned.

Biofuels in transport are promoted through an obligation by distributers. A strategy for alternative fuels and an operational program have been prepared focusing on the electrification of vehicle fleets. At present there is no biofuels production in Slovenia.

(c) Installed capacity per source

Table 5.240 shows the installed capacity per RES source in 2018 in Slovenia in terms of MW. The capacity of large hydropower is dominant representing 69% of the total RES capacity in Slovenia, followed by solar PV with 17%. Hydro pumped storage represents 11% of the total capacity while wood biomass and biogas each have 2%. Wind energy capacity is only 0.3% indicating the low wind potential in Slovenia. Total RES capacity reached 1,698 MW in 2018.

Table 5.240 **Installed RES capacity (MW) per source**

		2010	2015	2018
Hydro	[MW]	1074	1115	1163
Hydro pumped storage	[MW]	180	180	180
Wind	[MW]	0	5	5
Solar PV	[MW]	49	268	290
Wood biomass	[MW]	33	30	32
Biogas	[MW]	14	32	27
Total capacity	**[MW]**	**1350**	**1630**	**1698**

Source: SORS, Energy Agency

(d) Planned new major projects

Slovenia has plans to further exploit its remaining hydro potential. It is expected that the last hydro power plant in the lower Sava river (HPP Mokrice) will be built at the latest before 2030. The exact date depends on the length and the outcome of the environmental assessment process that has to be conducted again. Lower Sava hydro power plants are managed by Hidroelektrarne na Spodnji Savi, d.o.o., a subsidiary of Slovenia's largest state-owned power utility Holding Slovenian Power Plants (HSE). There are also plans for additional hydro power plants in the middle part of the Sava river.

There are 10 HPP planned with total capacity 300 MW although this project is facing strong environmental opposition. It is possible that only part of the plan will be realized due to restrictions related to Natura 2000 and other environmental concerns. An additional pumping storage unit is also planned after 2030, with a capacity of 400 MW in North-Eastern part of Slovenia (PHPP Kozjak). No other major projects are foreseen.

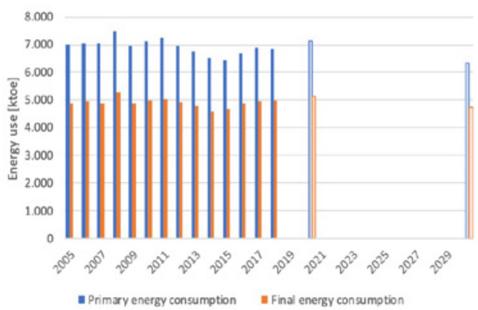
Slovenia does not have a lot of potential for wind power, but a large potential has been identified for solar PV, especially on the roofs of buildings. NECP foresees additional measures that will stimulate larger projects on the roofs of industries or buildings in the services sector that usually have better connections to the distribution network. Projections used for NECP show that by 2030 solar PV capacity could increase to 1,650 MW.

Energy Efficiency and Cogeneration

(a) National targets

Slovenia's national target for 2020 pursuant to Article 3 of Directive 2012/27/EU set in the National Energy Efficiency Action Plan is 7.125 Mtoe expressed in primary energy consumption or 5.118 Mtoe expressed in final energy consumption. The target for 2030, as adopted in the NECP and expressed in final energy consumption, is 4.717 Mtoe. Expressed in primary energy consumption the target is 6.356 Mtoe. Compared to 2007 PRIMES projection targeted energy use is 35% lower, meaning that Slovenia has set a more ambitious target than the one adopted by the EU. In 2018 both final and primary energy consumption were below the target level for 2020 and there is high expectation that the target will be met.

Figure 5.288 **Slovenia's energy efficiency target 2020 and 2030**



Source: SORS

Slovenia in its NECP also defines a target of 20% for final energy use reduction and 70% GHG emissions reduction in buildings. No target has been set for CHP.

Comparison of GDP growth and energy use in the period 2005-2018 shows that between 2005 and 2013 almost no decoupling had been reached, while after 2013 strong GDP growth did not result in energy use increase. Between 2013 and 2018 GDP has grown by 18% while final energy consumption increased by 4% and primary energy consumption by 1%.

5

(b) Incentive-based initiatives in the building sector and EU funded (or otherwise funded) energy efficiency programs in the building sector

In the past energy efficiency measures in the buildings sector were laid down in several documents: National energy efficiency plan, Long-Term Strategy for Mobilizing Investments in the Energy renovation of Buildings with its update, Operational Program for the Implementation of the EU Cohesion Policy in the period 2014 – 2020. A future strategy for the improvement of energy efficiency in buildings has been set in NECP and also in the new Long-Term Strategy for Mobilizing Investments in the Energy renovation of Buildings.

The most important measure for households promoting energy efficiency improvement in buildings is financial support in the form of subsidies or soft loans provided by Ecofund. Funds are available for insulation of façade or roof, new wooden energy efficient windows, mechanical ventilation with heat recuperation, installation of new wood biomass boilers, heat pumps or solar collectors or for a combination of measures. If a combination of measures is applied, a higher subsidy is available. Subsidies are also available for building or purchasing of a passive house or a flat in a passive building.

A special program has been designed for socially weak households, where 100% subsidy for energy efficiency measures in multifamily houses or substitution of old wood boilers is available. In cooperation with social centers a package for reducing energy poverty is also available for them, providing expert counseling on reducing energy use. Funds for the operation of Ecofund come from the government's own funds, by means of contributions paid per energy use in order to increase energy efficiency and from 2014 onwards from the Climate Fund.

In 2018 the Ecofund provided subsidies in the amount of 26.2 million EUR. An important measure supporting funding is energy consulting network for citizens (ENSVET) providing free advice on implementation of energy efficiency measures to households. The Ecofund funds the operation of the network. In the future, special attention must be given to the support of energy efficiency measures in buildings where old people live and to address non-economic barriers in multifamily houses, like reaching agreement on renovation, relations between tenants and owners (new instruments will be prepared for multifamily houses i.e. guaranty schemes).

For buildings in the public sector it is mandatory to implement an energy management system. Funds for public buildings are available as subsidies that are provided by Ecofund and Ministries and as soft loans provided by Ecofund. Cohesion Fund is an important source of funding for this sector. In 2019 some 21.1 mio EUR have been available from the Ministry of Infrastructure for public building renovation, while the Ecofund has planned 1.5 mio EUR in 2019-2020.

Measures are being implemented also through large energy suppliers obligation scheme and energy contracting. Very important action is also related to the education of employees that are involved in the preparation and overseeing of energy efficiency projects. Technical support through the ELENA project for the public sector has been obtained by the government and could provide much needed impetus. It is worth mentioning that Slovenia has set up a project office for the renovation of public buildings providing support to ministries and other public sector entities when preparing projects. However, its operation needs to be enhanced further.

Additionally, special attention must be given to buildings that are protected as cultural heritage. A methodology needs to be prepared for the assessment of qualified costs, while special tenders for grants can be provided under cohesion funds and some pilot projects already have been prepared.

Energy contracting is an important instrument for the implementation of energy efficiency measures in the public sector. During 2016-2018 a total of 32 projects were approved, with increasing number through this period.

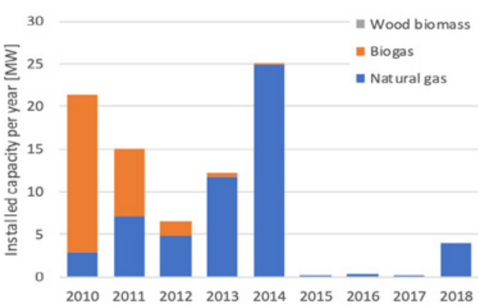
This instrument will be enhanced through the provision of new financial products to ESCOs and other support measures (i.e. trainings, expert and technical support to ESCOs, tool for evaluation of projects) so that it will be used also in other buildings.

Currently valid energy efficiency regulation for buildings has been in use since 2010 (Rules on efficient use of energy in buildings) and needs to be upgraded. New regulation will be prepared based on the Long-Term Strategy for Mobilizing Investments in the Energy Renovation of Buildings and it will be published in due course.

(c) Cogeneration: Regulatory framework, installed capacity

Co-generation of electricity and heat (CHP) is supported through a scheme for electricity produced from renewable source and with high-efficiency cogeneration. The support scheme was first introduced in 2009 and overhauled in 2014. Support is limited to installations up to 20 MW for CHP units. The duration of support for CHP is 10 years. Co-generation is also promoted by mandatory use of RES, CHP and waste heat in the district heating systems (Article 322 of Energy law). For electricity produced in CHP a guaranty of origin can be received.

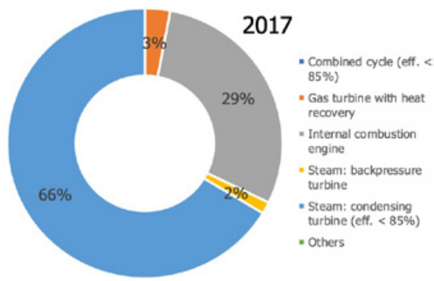
Figure 5.289 **Installed CHP capacity per year for the period 2010-2018**



Source: Energy Agency and Borzen

Between 2010 and 2014 new CHP units were installed totalling 80 MW, mainly using biogas and natural gas. As can be seen in Figure 5.289, after 2014 there has been a break in new installations of CHP units due to an overhaul of the support scheme and preparation of tenders. First tender under the new scheme was published in December 2016. Support for CHP's under this new scheme is less favorable and that is also reflected in the low numbers of newly installed capacities after 2014. Based on SORS data total CHP capacity in 2017 in Slovenia amounted to 374 MW. The structure of installed CHP capacity is presented in Figure 5.290.

Figure 5.290 **Structure of total installed CHP capacity in Slovenia per technology (2017)**



Source: SORS

(d) Planned major projects

A new natural gas fired CHP plant will be built in Slovenia's capital Ljubljana with 142 MW of installed power capacity. The investor is the Energetika Ljubljana Company which is managing the district heating network in Ljubljana. A contract was signed in 2019 and it is expected that the plant will be in operation by the end of 2021 or beginning of 2022. Combined cycle technology will be used, substituting two of three coal fired units and reducing coal consumption by 70%.

NECP foresees an increase of installed capacity in the industrial sector while in district heating a decrease of installed capacity is projected, not taking into account the larger units in Ljubljana and Šoštanj. More than half of the increase in industry is due to biomass units.

Decrease in district heating applications comes from the stagnation of CHP units with gas that are substituted by CHP units and boilers on biomass, heat pumps (using geothermal energy and waste heat), waste heat utilization from industry and solar collectors. Table 5.241 shows a projection of anticipated new CHP capacities until 2030.

Table 5.241 **Projection of new CHP capacities in Slovenian industry based on NECP**

		2020	**2025**	**2030**
Gas turbine	[MW]	0.0	2.0	16.0
Internal combustion engine	[MW]	0.8	1.8	3.2
Internal combustion engine - gasification of biomass	[MW]	3.3	6.6	13.1
Steam turbine & ORC	[MW]	2.6	6.3	10.5
Total	**[MW]**	**6.7**	**16.6**	**42.8**

Source: Jožef Stefan Institute

Energy Investment Outlook

The estimated investment volume for the implementation of the energy part of the NECP scenario from 2021 to 2030 is estimated at over 6.5 billion EUR, which requires excellent cooperation between the most important stakeholders. Table 5.242 provides information on the estimated investments per sector.

Table 5.242 **Estimation of necessary investment needs between 2021 and 2030 for the implementation of energy part of the NECP scenario**

Sector	**Estimated investment needs [million EUR]**
Solar PV	1,208
Wind farms	142
Other RES-electricity projects	13
District heating	80
Upgrades of electricity transmission network	407
Upgrades of electricity distribution network	4,203
Centralized energy supply (including large power plants)	358
Pilot projects (synthetic gas, geothermal, etc.)	100
Total	**6,511**

Source: NECP

Total investment needs for the realization of non-energy projects covered by Slovenia's NECP are estimated at more than 28 billion EUR and include an upgrade of the railway system, deep renovation of existing building stock, sustainable upgrade of the transport sector, etc.

By implementing the proposed measures in the framework of the new NECP, Slovenia can achieve a 6% reduction in final energy use by 2030 and more than 20% by 2040 in comparison to 2017. Additionally, the share of RES and waste in final energy consumption can increase by more than 35% compared to 2017.

References

(1) Statistical Office of Slovenia (2019), Energy Statistics, Slovenia, annually https://pxweb.stat.si/SiStatDb/pxweb/sl/30_Okolje/

(2) Statistical Office of Slovenia (2019), Joint Energy Questionnaire

(3) Energy Agency (2019), Report on the Energy Sector in Slovenia for 2018, https://www.agen-rs.si/documents/10926/38704/Poro%C4%8Dilo-o-stanju-v-energetiki-2018/f0ee7a7a-3b8d-48b3-8a29-8cdc258d2e69

(4) Plinovodi (2019), Yearly report 2018, http://www.plinovodi.si/media/4879/lp-2018.pdf

(5) Kerčmar J., Natural gas reservoirs on the oil-gas field Petišovci, Geologija 61/2, 163-176, Ljubljana 2018

(6) Agency of the Republic of Slovenia for Commodity Reserves (2018), Letno poročilo 2017, Ljubljana, 2018, https://www.dbr.si/wp-content/uploads/2018/04/Letno-porocilo-ZRSBR-2017-sprejeto-na-Vladi.pdf

(7) EURACOAL, 2020, Coal industry across Europe, http://euracoal2.org/download/Public-Archive/Library/Coal-industry-across-Europe/EURACOAL-Coal-industry-across-Europe-7th.pdf

(8) Ministrstvo za infrasturkturo (2010), Akcijski načrt za obnovljive vire energije za obdobje 2010-2020 (AN OVE) Slovenija, Ljubljana, 2010, https://www.energetika-portal.si/fileadmin/dokumenti/publikacije/an_ove/an_ove_2010-2020_final.pdf

(9) Ministrstvo za infrastrukturo (2015), Akcijski načrt za energetsko učinkovitost za obdobje 2014-2020 (AN URE 2020), Ljubljana, 2015, https://www.energetika-portal.si/fileadmin/dokumenti/publikacije/an_ure/an_ure_2020_sprejet_maj_2015.pdf

(10) Ekosklad (2019), Letno poročilo Eko sklada, slovenskega okoljskega javnega sklada, za leto 2018, Ljubljana, 2019, https://ekosklad.si/informacije/o-skladu/letna-porocila/letno-porocilo-2018

(11) Ministrstvo za infrastrukturo (2020), Celovit Nacionalni energetski in podnebni načrt Republike Slovenije, Ljubljana, 2020, http://84.39.218.201/MANDAT18/VLADNAGRADIVA.NSF/277bdf36cd5b7373c1256efa00399a6b/670f09be03d9b719c1258518002acdea/$FILE/NEPN_5.0.pdf

(12) Petelin-Visočnik (2019), Podnebno ogledalo 2019 – Stavbe, Končno poročilo, LifeClimatePath2050, Ljubljana, 2019, https://www.podnebnapot2050.si/wp-content/uploads/2019/06/Podnebno_Ogledalo_2019_Zvezek3_Stavbe_KONCNO-2.pdf

(13) Borzen (2020), Pregled elektrarn v shemi po obdobjih, excel file available on https://www.borzen.si/Portals/0/SL/CP/OVE%20Shema%20pregled%20-%20stevila%20in%20moci.xls

(14) Energy Agency (2020), Energy Agency web page on tenders for CHP and RES electricity production, https://agen-rs.si/web/portal/poziv2019december

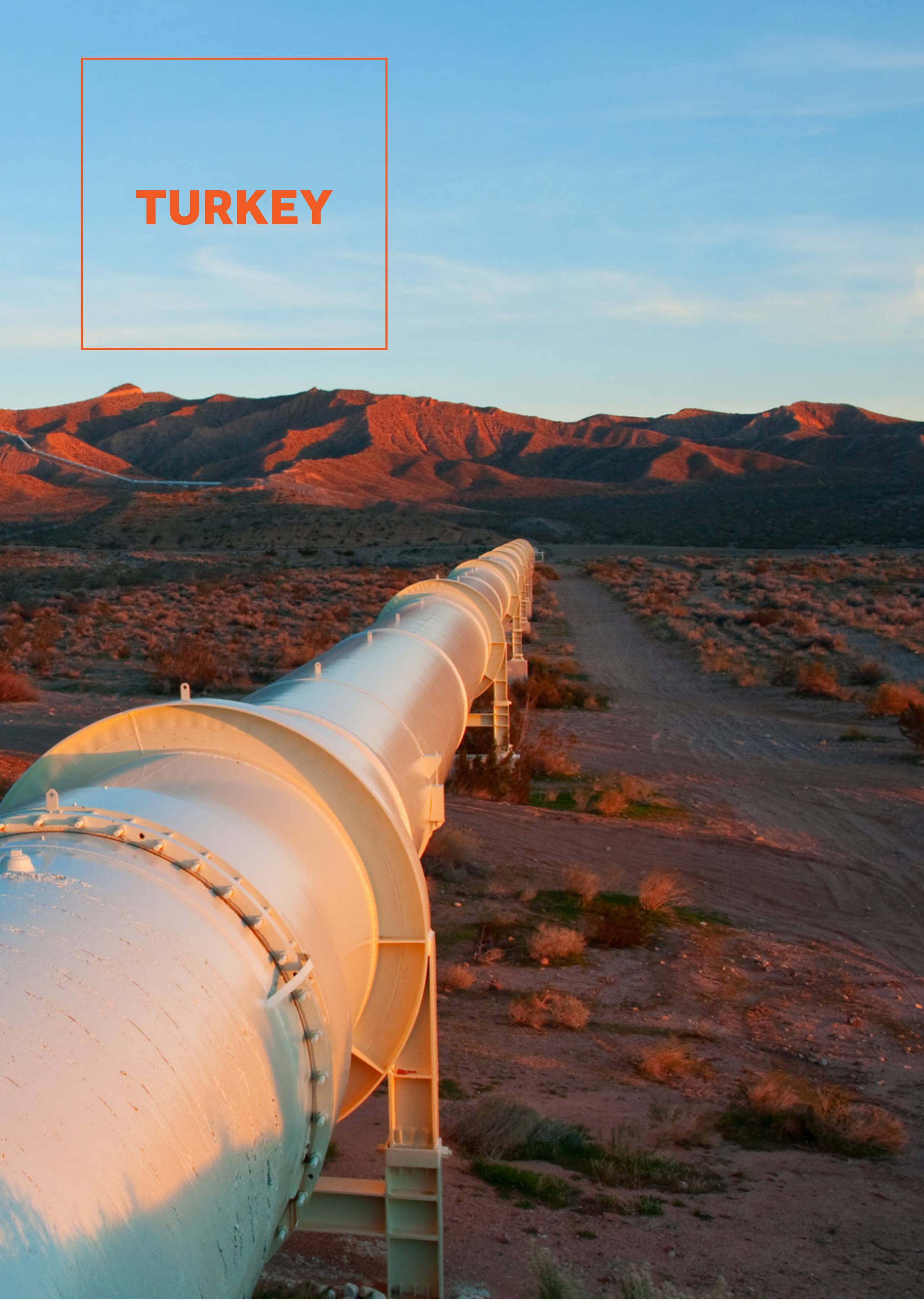
(15) IMAD (2019), Jesenska napoved gospodarskih gibanj 2019, IMAD, Ljubljana, 2019, (Year 23, number 1)

(16) PETROL (2019), Letno poročilo 2018, Petrol, Ljubljana, 2019, https://www.petrol.eu/binaries/content/assets/skupina-petrol-slo/2018/porocila/2019/letno-porocilo-petrol-2018.pdf

(17) World Energy Council (2019), Country profile Slovenia, 2019, https://trilemma.worldenergy.org/#!/country-profile?country=Slovenia&year=2019

(18) ELES (2019), Network Development Plan 2019-2028, Ljubljana, 2019, https://www.eles.si/Portals/EN/Document/eles_RN_2019-2028.pdf

TURKEY



Turkey

Economic and Political Background

Turkey's GDP expanded 5.9% year-on-year in the fourth quarter of 2020, softening from the third quarter's 6.3% rise and coming in under market expectations. The reading was largely driven by slower growth in domestic demand and a persistent drag from the external sector. For the year as a whole, GDP rose 1.8% (2019: +0.9%). The Turkish economy was therefore one of the few in the world to achieve growth in 2020, despite pandemic-induced restrictions. However, IMF estimates that Turkey's GDP fell by 5.0% in 2020 and is expected to expand by 5.0% in 2021.

On the domestic front, household expenditure was the main driver of growth in the fourth quarter, thanks to a robust credit extension fomented by the government. That said, private consumption slowed amid the tightening of Covid-19 restrictions, growing 8.2% year-on-year in Q4 (Q3: +8.5% y-o-y). Moreover, capital spending growth slowed markedly to 10.3% in the quarter (Q3: +21.9% y-o-y). Meanwhile, public expenditure rose 6.6% in annual terms in Q4, after increasing 0.8% in Q3.

On the external front, exports of goods and services stagnated after collapsing in the previous quarter (Q4: +0.0% y-o-y; Q3: -22.1% y-o-y). Meanwhile, imports rose 2.5% annually in the fourth quarter (Q3: +16.4% y-o-y). On a seasonally-adjusted quarter-on-quarter basis, economic growth slowed to 1.7% in Q4 from the previous quarter's 15.9%.

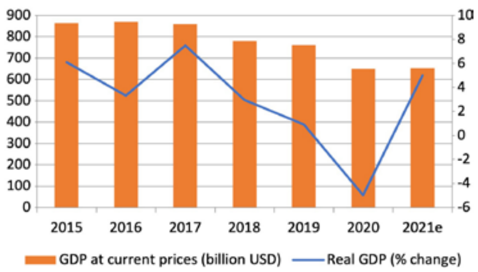
Looking ahead, economic growth is expected to firm this year. Domestic and foreign demand is likely to strengthen as the country continues to ease restrictions and the global rollout of vaccines pushes forward, allowing more economies to reopen. Nevertheless, lira weakness and elevated inflation, coupled with uncertainty regarding the trajectory of the pandemic, will keep the outlook clouded.

President Erdogan won the June 2018 presidential elections in the first round, finally consolidating his power. With this vote, the transition to the new presidential system has been completed. In the June 2018 parliamentary elections, the alliance of Erdogan's AKP with the nationalist MHP party won 53.7% of the votes. In the March 2019 local elections, the AKP was again the party with the highest percentage in the vote, but the oppositional CHP won mayoral elections in several large cities. The next presidential and general elections are due to take place in June 2023. However, early general elections cannot be ruled out.

Domestic and regional political issues will continue to impact Turkey's economy, in particular investor sentiment and the exchange rate. The south-eastern part of the country remains affected by the civil war in Syria and cross-border interventions by the Turkish army. Over the past couple of years, Turkey has adopted an increasingly assertive foreign policy in order to establish itself as a leading power in the Mediterranean and the Middle East. Besides engagement and military incursions in Syria and Iraq, Ankara has set up a military base in Qatar, intervened in the civil war in Libya, supported the Azerbaijan forces in their armed conflict with Armenia, and sent gas exploration ships into contested areas in the Aegean Sea, where Turkey has overlapping maritime claims with Greece and the Republic of Cyprus.

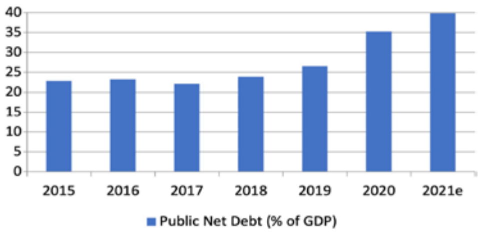
Relations with the EU and the US remain strained, despite the fact that Ankara has recently attempted to ease tensions (e.g. resuming talks with Athens over overlapping claims and setting up a joint working group with Washington regarding US sanctions imposed over Ankara's purchase of Russian S-400 missile defence systems).

Figure 5.291 **Turkey's GDP and its annual GDP growth**



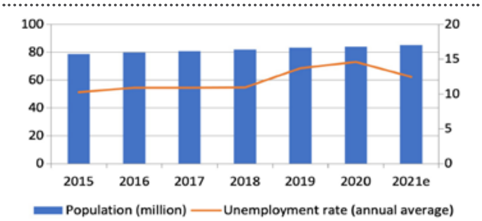
Source: IMF World Energy Outlook (October 2020)

Figure 5.292 **Turkey's Public Net Debt**



Source: IMF World Energy Outlook (October 2020)

Figure 5.293 **Turkey's Population and Unemployment Rate**



Source: IMF World Energy Outlook (October 2020)

Energy Policy

(a) National Energy Policy

The main guidelines of the Turkish Energy Policy are the following: (a) 2023 Goals (released in 2010), (b) the National Renewable Energy Action Plan 2013-2023 (released in 2014), (c) the Ministry of Energy and Natural Resources (ETKB) Strategic Plan 2015-2019 (released in 2015) and (d) the 11th Development Plan (2019-2023). The main objective of Turkish energy policy is to provide the highest contribution to national welfare by supplying uninterrupted, sustainable, high quality, reliable and cost-effective energy from diversified sources in the most efficient and environmentally conscious manner (Strategic Plan 2015-2019).

In this regard the main priorities are highlighted below:

(i) Maximum utilization of renewable and indigenous sources,
(ii) Diversification of energy suppling countries and supply routes,
(iii) Reduction of energy intensity,
(iv) Introduction of nuclear energy into the energy mix,
(v) Reduction of environmental impacts of the energy system,
(vi) Development of a competitive energy market.

More specifically the following legal structure governs the implementation of above policies:

- Petroleum Law 6491 (2013) regulates the Exploration & Production of oil and gas.
- Petroleum Market Law 5015 (2003) regulates midstream and downstream activities in the oil sector.
- Mining Law 3213 (1985) and its amendments regulate the mining of solid fuels.
- Geothermal - Resources Law 5686 (2007) and its amendments regulate the exploration and extraction of geothermal resources.
- Electricity Market Law 4626 (2001) and its amendment 6446 (2013).
- Natural Gas Market Law (2001) and its amendments form the backbone of the energy market. They are supported by tens of regulations.
- Renewable Energy Law 5346 (2005) and its amendment 6094 (2011) support the electricity generation from renewable resources.

(b) Governmental institutions

After constitutional amendments of 2017 to the new presidential system, in 2018, some of the existing institutions were abolished and new ones were established.

Ministry of Energy and Natural Resources (ETKB) is still the main institution of the government to prepare and implement the energy policies of Turkey in cooperation with other relevant institutions and guided by the Development Plans.

General Directorate of Energy Affairs (EIGM) extended its duties as the main organ for policy development and implementation of ETKB. Its duties also include renewable energy promotion and deployment and the energy efficiency policies.

General Directorate of Renewable Energy (YEGM) responsible for renewable energy and energy efficiency policies has been abolished. Its duties were assigned to the EIGM.

BOTAŞ, established in 1973 to build and operate petroleum pipelines became in 1980's the natural gas monopoly. Despite the creation of the natural gas market in 2001 the state-owned company is still the largest trader and natural gas transmission system operator.

Turkish Electricity Transmission Company (TEİAŞ) is the Transmission System Operator of Turkey.

Electricity Generation Company (EÜAŞ) owns and operates the remaining generation assets of the state after the privatization and wholesales the electricity.

Turkish Electricity Trading Company TETAŞ, responsible for the wholesale of electricity bought from EÜAŞ and from the private generators in the framework of vested contracts of the pre-liberalization era, has been abolished in July 2018. Its responsibilities, including the purchase guaranty for electricity generated from Akkuyu nuclear power plant are transferred to EÜAŞ.

State Hydraulic Works DSI is responsible for the utilization of water resources.

Energy Exchange Istanbul (EPİAŞ) has been established in 2015. The shareholders are TEİAŞ (30%), Istanbul Stock Exchange (30%) and electricity and natural gas market participants (40%). After the unbundling of BOTAŞ, half of the TEİAŞ shares will be transferred to the natural gas transmission system operator.

General Directorate of Petroleum Affairs (PIGM) responsible for the regulation of exploration and production activities in the oil and gas sector was abolished. Its duties were transferred to the newly established General Directorate of Mining and Petroleum Affairs (MAPEG).

General Directorate of Mining and Petroleum Affairs (MAPEG) is responsible for licencing and supervision of exploration and production activities in mining and oil & gas industry since July 2018.

Turkish Atomic Energy Authority (TAEK) was the regulatory, research and radiation safety agency in nuclear field in Turkey. With the establishment of the Nuclear Regulatory Agency (NDK) in July 2018 all the regulatory activities were taken over by NDK. In March 2020, TAEK has been abolished and its remaining duties like nuclear research were transferred to the newly established TENMAK.
Turkish Energy Nuclear and Mining Research Agency (TENMAK), established on 28 March 2020 will be responsible for energy, nuclear, boron and rare earth elements research.

The Energy Market Regulatory Authority (EPDK) regulates the market activities in electricity natural gas, petroleum and liquefied petroleum gas markets.

Strategy and Budget Board (SBB) is the newly created agency of the new presidential system. SBB acts like the former State Planning Organization (DPT) in the field of economic and social planning and also took over some duties of the Ministry of Finance.

Competition Authority (RK) enforces the Law No. 4054 on Protection of Competition in cases of anticompetitive practices and has the responsibility to approve or dismiss mergers and acquisitions.

Energy Demand and Supply

a) National energy demand

Between 2013-2018 Turkey's total final energy consumption (TFC) increased 23.93% from 88.07 to 109.15 Mtoe (Table 5.243, Ministry of Energy and Natural Resources,2019). TFC in 2017 was the highest with 111.650 Mtoe and reduced in 2018 due to sluggish economy. Oil products have the largest share in TFC with 38.18%. The share of oil and electricity in TFC increased marginally between 2013-2018. Oil demand in the transport sector increased its share in TFC from 23.05% in 2013 to 25.49% in 2018. In the same period the share of natural gas in TFC increased substantially from 19.25% to 22.20%. The share of coal consumption was reduced from 16.14% to 12.55%.

b) National energy supply

Turkey's total primary energy supply increased from 116.3 Mtoe in 2013 to 145.3 Mtoe in 2017 but due to the economic problems reduced to 143.7 Mtoe in 2018 (Figure 5.294). In the 2013-2018 period total primary energy supply increased by 23.55%. We may observe an increase of the share of Wind+Solar+Geothermal from 3.5% to 8.1% and a decrease of the share of natural gas from 32.4% to 28.7% in the same period. The low share of Hydro with 3.58% in 2018 is the result of low water income and may increase in 2019 and in the following years.

Table 5.243 **Total final consumption TFC (Mtoe) and its sectoral breakdown in 2013 and 2018**

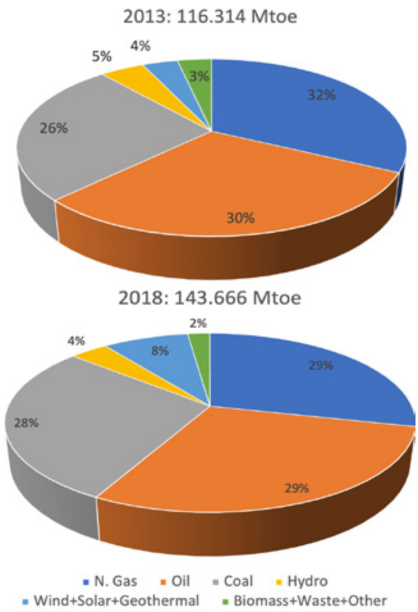
	Coal (1)	Oil (2)	N. gas	Electric.	Biofuels +waste (3)	Geoth. +Heat	Solar	Total
2013								
TFC	14.222	33.425	16.957	16.932	3.192	2.551	0.795	88.074
Share	16.14%	37.95%	19.25%	19.22%	3.62%	2.89%	0.90%	
Sectoral breakdown								
Industry	8.334	3.961	6.145	7.920	0	1.088	0.277	27.725
Share in TFC	9.46%	4.49%	6.97%	8.99%	0	1.23%	0.31%	31.45%
Transport	0	20.307	0.306	0.071	0.050	0	0	20.734
Share in TFC	0	23.05%	0.34%	0.08%	0.05%	0	0	23.52%
Other (4)	5.712	9.017	10.424	8.941	3.143	1.463	0.518	39.218
Share in TFC	6.48%	10.23%	11.83%	10.15%	3.56%	1.66%	0.58%	45.49%
2018								
TFC	13.705	41.681	24.237	21.768	2.548	4.332	0.877	109.149
Share	12.55%	38.18%	22.20%	19.94%	2.33%	3.965%	0.80%	100%
Sectoral breakdown								
Industry	9.498	3.767	9.434	10.095	0.834	2.343	0.307	36.277
Share in TFC	8.70%	3.45%	8.64%	10.92%	0.76%	2.14%	0.28%	33.23%
Transport	0	27.825	0.355	0.114	0.159	0	0	28.452
Share in TFC	0	25.49%	0.32%	0.10%	0.14%	0	0	26.06%
Other (4)	3.897	9.734	13.887	11.559	1.555	1.989	0.570	43.191
Share in TFC	3.57%	8.91%	12.72%	10.59%	1.42%	1.82%	0.52%	39.55%

(1)Including asphaltite and industrial gases,
(2) including petroleum coke,
(3) including biofuels, biomass, waste and firewood
(4) including non-energy use of oil products like petrochemical feedstock

Rounding may cause small differences
2013 figures last update: 11.06.2018, 2018 figures published on 15.11.2019

Source: Ministry of Energy and Natural Resources, 2019

Figure 5.294 **Total Primary Energy Supply of Turkey, 2013 and 2018**



Source: Ministry of Energy and Natural Resources, 2019

c) Energy balance

The energy balance of Turkey is shown in three tables (Tables 5.243-5.245). Table 5.243 shows the Total Final Consumption, Table 5.244 the Energy Supply, while Table 5.245 shows the Energy Transformation and Losses.

d) Energy Mix

In terms of Primary Energy Supply the energy mix of Turkey in 2018 was as follows: Coal (28.4%), Oil (29.2%) and Natural gas (28.7%) have nearly equal shares in Turkish energy supply in 2018. The sum of wind, solar and geothermal energy in 2018 was 8.1% more than double since 2013. In the same period the share of natural gas was reduced by 3.7%. Of the indigenous production of fossil fuels only coal has a substantial contribution to the energy mix. The share of local coal in energy supply was 11.5% in 2018. It should be further noted that the Turkish government is promoting the introduction of nuclear energy into the energy mix and investments in renewables in order to increase the share of indigenous resources.

Table 5.244 **Energy Supply of Turkey 2018 (Mtoe)**

	Coal (1)	Oil (2)	N. gas	Electric.	Bio +waste	Hydro	Wind	Geoth.	Solar	Total
Production(+)	16.547	2.994	0.359	3.014	5.155	1.716	8.343	1.547	39.675	
Import(+)	24.521	49.550	41.547	0.213						115.792
Export(-)	0.148	5.095	0.555	0.268						6.067
Bunker(-)		4.978								4.978
Stock change(+/-)	-0.020	-0.556	-0.181							-0.756
Total supply	40.861	41.913	41.171	-.0055	3.014	5.155	1.716	8.343	1.547	143.666
Share	28.44%	29.17%	28.65%	-0.03%	2.09%	3.58%	1.19%	5.80%	1.07%	
Statis. difference	0.313	0.356								0.668

Source: Ministry of Energy and Natural Resources, 2019

Table 5.245 **Energy Transformation and Losses 2018 (Mtoe)**

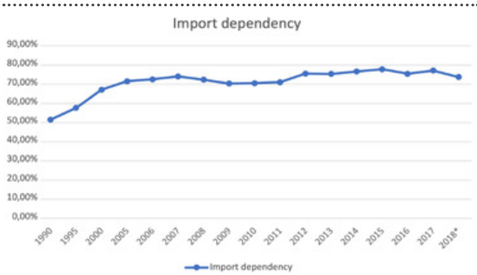
	Coal (1)	Oil (2)	N. gas	Electric.	Bio +waste	Hydro	Wind	Other Heat	Geoth.	Solar	Total
Transformation sector	-27.156	-0.232	-16.934	21.823	-0.465	-5.155	-1.716	2.378	-6.389	-0.671	-34.517
Elect.+Heat generation	-26.850	-0.229	-16.144	26.213	-0.465	-5.155	-1.716	2.807	-6.389	-0.671	-28.597
Coke Ovens+Blast furnace	0.849									0.849	
Oil refineries		4.754	-0.753	-0.150				-0.429		3.422	
Own use+losses	-1.156	-4.758	-0.037	-4.240						-10.192	

Source: Ministry of Energy and Natural Resources, 2019

e) Energy Dependence

Over the last decades Turkey's energy import dependency grew from over 50% to over 70% and reached its highest level of 77.9% in 2015 (Figure 5.295). The result of the efforts to utilize local resources were rather modest. Many investment projects for new hydropower and coal capacities were mainly hindered by NGO resistance and a deteriorating investment climate.

Figure 5.295 **Turkey's energy import dependency 1990-2018 (%)**



Source: Eurostat, 2019 and Ministry of Energy and Natural Resources, 2019, (*)2018 figure may be subject to changes.

The Energy Market

(a) Oil supply and demand

The total final consumption of oil products increased from 33.425 Mtoe in 2013 to 41.681 Mtoe in 2018 by 24.7%. This is mainly due to the increased consumption in the transportation sector; the industry substituted part of its oil demand by using natural gas (Table 5.246).

Table 5.247 **Sectoral breakdown of total final consumption of oil in 2013 and 2018**

	2013		2018	
Sector	Mtoe	%	Mtoe	%
Industry	3.961	12	3.767	9
Transport	20.307	61	27.825	67
Other	9.017	27	9.734	24
Total Oil Products	33.425	100	41.681	100

Source: Ministry of Energy and Natural Resources, 2019

After three consecutive years of continuous growth, total petroleum product sales decreased by 2,30% to 27.807.223 tonnes in 2018 and the total refinery production decreased by 13,60% to 25.002.286 tonnes (Turkish Petroleum Market Report 2018, EPDK 2019). The demand increases for diesel, reported in previous SEE Energy Outlook 2015/16 continued in the years 2015-2017. Diesel consumption increased from 20.6 Mil t in 2015 to 24.2 Mil t in 2017 by 17.5%. Following the economic downturn in 2018, the diesel demand reduced to 23.6 Mil t by 2.4%. The decrease of gasoline demand reported in previous reporting period did not continue. Gasoline consumption increased from 2.1 Mil t in 2015 to 2.3 Mil t in 2018 by 11%.

(b) Oil imports

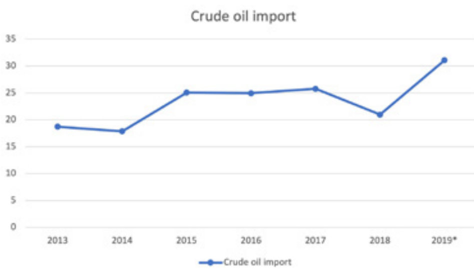
Turkey's main import items in the oil sector are crude oil and diesel. While crude oil imports decreased in 2018 by 18.6% due to economic slowdown to 20.9 Mill t, diesel imports increased slightly by 2.2% to 13.7 Mill t. With the new Star refinery in the west coast utilizing full capacity since August 2019 Turkey's crude oil imports have increased substantially. According to preliminary data for 2019 Turkey imported some 31.1 Mill t of crude oil.

Table 5.246 **Turkey's petroleum market, 2015-2018 (t)**

Production Type	Production				Import				Export				Domestic Sales(Consumption)				TOTAL DELIVERY			
	2015	2016	2017	2018	2015	2016	2017	2018	2015	2016	2017	2018	2015	2016	2017	2018	2015	2016	2017	2018
Gasoline Types	5.113.058	5.181.861	5.369.216	4.684.112	-	-	-	-	3.115.474	2.888.063	3.167.398	2.439.858	2.097.248	2.234.045	2.383.254	2.329.920	2.097.248	2.234.045	2.383.254	2.329.920
Diesel Types	8.509.777	9.582.347	10.395.000	9.292.051	11.891.847	12.381.706	13.455.723	13.749.187	27.526	71.405	233.080	145.962	20.564.852	22.322.578	24.166.321	23.576.884	20.669.449	22.479.390	24.573.902	24.186.858
Fuel Oil Types	547.712	-385.850	-72.009	61.205	919.709	1.163.616	828.758	553.552	982.337	282.001	252.068	235.830	604.054	583.539	492.356	359.916	1.564.963	583.539	492.356	359.919
Aviation Fuels	5.024.287	4.486.633	4.837.246	4.786.244	166.296	341.285	196.906	481.734	3.757.478	3.528.540	3.770.931	3.874.909	1.319.241	1.338.751	1.262.517	1.260.675	1.319.436	1.338.775	1.262.517	1.260.675
Marine Fuels	2.344.697	2.346.900	2.154.285	1.766.077	75.954	14.699	1.211	10.254	2.434.117	2.261.816	2.097.170	1.785.550	234	44.240	41.220	43.805	507.332	1.497.744	1.551.417	2.036.934
Kerosene	57.820	11.728	4.163	3.884	-	-	-	-	-	-	-	-	56.609	14.821	4.686	2.698	56.609	14.821	4.686	2.698
Others	6.267.448	7.587.583	6.258.144	4.408.714	1.512.096	1.215.482	2.404.283	2.946.058	488.645	656.683	569.410	392.907	182.465	179.898	190.626	213.321	-	179.898	190.626	213.321
TOTAL	27.884.799	28.731.208	28.837.116	26.802.287	14.685.902	15.116.847	18.508.881	17.740.785	10.806.677	8.888.416	10.090.008	8.876.018	24.824.703	26.717.871	28.480.879	27.807.223	28.216.037	28.328.018	30.778.767	30.419.326

Source: Turkish Petroleum Market Report 2018, EPDK 2019. Total Delivery is the sum of domestic sales, exported registered deliveries and transit regime deliveries. Usage of minus by Fuel Oil shows that in stock or imported product used by refinery once again for new other product(s).

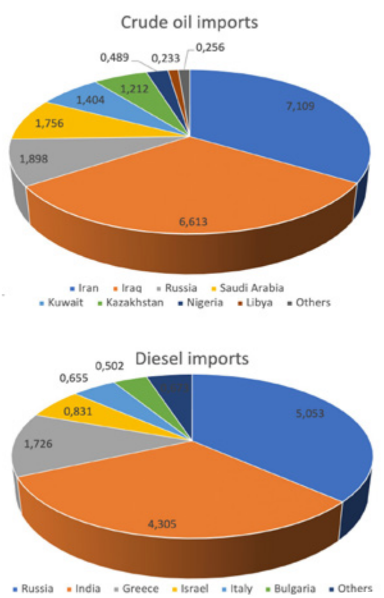
Figure 5.296 **Crude oil imports 2013-2019 (t)**



Source: Petroleum market reports 2013-2018, Petroleum market report December 2019, Energy Market Regulatory Authority EPDK.ges.

In 2018, the majority of crude oil imports were realized from Iran (33.9%) and from Iraq (31.5), followed by Russian Federation (9%), Saudi Arabia (8.4), Kuwait (6.7%) and Kazakhstan (5.8%). Diesel was imported mainly from Russian Federation (36.8%) and India (31.3%); followed by Greece (12.6%), Israel (6%) and other countries.

Figure 5.297 **Crude oil and diesel imports by country 2018 (Mill t)**

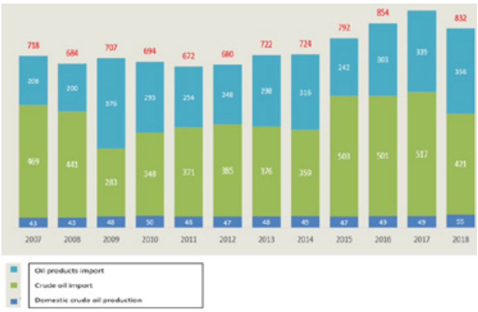


Source: Petroleum Market Report 2018, Energy Market Regulatory Authority EPDK, 2019.

After the US administration ended the sanction waivers, Turkey in July 2019 ceased importing crude oil from Iran. The gap was filled with increased imports from other countries.

According to preliminary figures the share of the Russian Federation has increased remarkably. Figure 5.298 shows Turkey's oil imports together and its local crude oil production.

Figure 5.298 **Oil imports and domestic crude oil production 2007-2018 (Thousand barrels per day)**

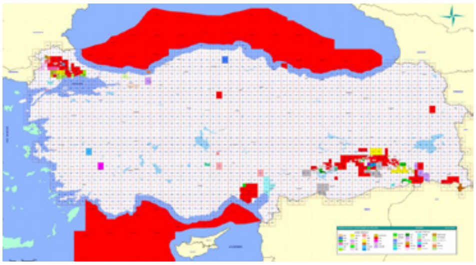


Source: TPAO Sectoral Report 2018, Turkish Petroleum Corporation, May 2019, EPDK Oil Market Reports, Energy Market Regulatory Authority

(c) Upstream sector - domestic production and exploration

Turkey's recoverable crude oil reserves in 2018 were 366 Mill barrels and without new discoveries the deposits will be depleted in 18 years. The oil is produced mainly in the Batman and Adiyaman basins in south-eastern Turkey and from old fields with declining well efficiency. The industry is extending its efforts for exploration of unconventional resources in Southeastern basins and for exploration in other basins. Off-shore exploration in the Black Sea and in the Mediterranean is also in focus. Map 5.71 shows hydrocarbon exploration and production licences held by companies.

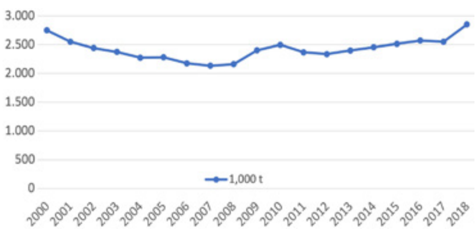
Map 5.71 **Exploration and production licences in Turkey**



Source: MAPEG General Directorate for Mining and Petroleum Affairs, 2019. Areas in red colour indicate TPAO licences.

In 2018, a total of 157 licences were active and 107 wells (67 by Turkish Petroleum Corporation TPAO and 38 by other companies) were drilled. 51 of them were exploration wells and the remaining 56 production wells (Sector report 2018, TPAO 2019). Since 2012, TPAO intensified its offshore exploration activities both in Black Sea and Mediterranean. The crude oil production of Turkey exceeded for the first time in 1968 the 3 Mill t mark, but this level could not be maintained in the following decades. After decreasing to 2.134 Mill t in 2007, the production reached the highest level of the last 20 years in 2018 with 2.851 Mill t. Approximately 67% of the production was realized by TPAO. Figure 5.299 shows the development of crude oil production in Turkey during the last 20 years.

Figure 5.299 **Crude oil production in Turkey, 1999-2018**



Source: PIGM (predecessor of MAPEG)

Latest Major discovery in the Black Sea

According to an announcement on August 21 by Turkey's president Recep Tayyip Erdogan a major gas field has been discovered in the Turkish section of the Black Sea. Hailing the find Turkey's president said that " this is a historic step" for the country's troubled economy and its energy security. Presenting details of this latest energy find, Mr. Erdogan said that following exploration activity by TPAO, the state-owned petroleum company, a 320 by cubic metres gas deposit had been found.

The deposit was identified following extensive seismic research and exploration drilling some 145 kms offshore from the town of Zonguldak in the Black Sea.

The precise drilling location known as Tuna 1 is located very near the well-known Polshkov and Andrusen geological ridges, and neighbours other major finds such as the Neptun and Skifska reservoirs in the Romanian and Ukrainian sectors respectively. The size of the field, that needs to be confirmed with additional appraisal drilling, would be approximately 40% as large as Egypt's supergiant Zohr field which is offshore in the Nile delta in Egypt and has been producing since 2017. In October, 2020 Tuna 1 well reached a total depth of 4,775 m and encountered an additional 30 m gas-bearing reservoir in Early Pliocene-Late Miocene sands and raised estimated gas potential to 405 (Oil&Gas Journal, Oct 19, 2020). "As a country that has suffered problems for years as a result of our dependence on foreign energy sources, I believe that we can now look to the future in greater confidence", Mr Erdogan observed.

Map 5.72 **Turkey's latest gas discovery in the Black Sea**

A detailed analysis of this new discovery by Turkey in the Black Sea and the potentially huge implications that this find is bound to have for the country's energy supplies, the strengthening of its energy base and for its economy is currently being prepared by IENE's team and will be released early in September.

(d) Downstream and midstream sectors infrastructure (Refineries, Pipelines, Storage, Terminal and Domestic Oil Market)

After the shutdown of the Ataş refinery in Mersin in the Mediterranean coast in 2004, Turkey was lacking refining capacity to satisfy increasing local demand for fuels. In 2018, Turkey had four refineries in operation with a total crude refining capacity of 30 mill t/year all belonging to TÜPRAŞ of the Koç Group.

Izmit refinery, 70 km east of Istanbul, established in 1961 has a refining capacity of 11.3 mill t/year and serves Istanbul and the region around Marmara Sea. İzmit Refinery has one of the highest conversion rates in the world, with a Nelson Complexity value of 14.5 (TÜPRAŞ, 2020).

Izmir refinery located in Aliağa 60 km north of Izmir with 11.9 mill t/year refining capacity supplies the western regions of Turkey. İzmir refinery has a 7.66 Nelson Complexity. In 2018 a total of 9.7 million tons of raw materials, including 9.4 million tons of crude oil and the remainder being semi-finished products was processed in İzmir Refinery (TÜPRAŞ, 2020).

Kırıkkale refinery located 80 km east of Ankara has a capacity of 5.4 mill t/year and serves the central and eastern provinces of the country. The refinery receives crude oil via pipeline from the Mediterranean harbour of Ceyhan. To distribute oil products, Kırıkkale refinery has Turkey's largest road tanker filling capacity (TÜPRAŞ, 2020).

Batman refinery is located in Southeast Turkey, close to the crude oil producing basins and has a capacity of 1.4 mill t/year. The refinery with a Nelson complexity of 1.83 has no upgrading units and is processing heavy crude oil from domestic fields of the region (TÜPRAŞ, 2020). The fifth and newest refinery in Turkey is the STAR refinery, commissioned at the end of 2018. The STAR refinery is located just 4 km south of the Izmir refinery of TÜPRAŞ and belongs to SOCAR from Azerbaijan. In August 2019 the STAR refinery reached its planned capacity of 10 mill t/year. STAR refinery will produce 4.8 mill t/year diesel, 1.6 mill t/year aviation fuel, 0.7 mill t/year Petroleum coke and 0.3 mill t/year LPG mainly destined for the domestic fuel market. The STAR refinery will also supply the PETKIM petrochemical complex of SOCAR on the same site with 1.6 mill t/year Naphtha, 0.4 mill t/year Xylene and 0.5 mill t/year Reformat (SOCAR, 2020). Table 5.248 shows the processing capacities of TÜPRAŞ and STAR refineries and market demand.

Table 5.248 **Refinery capacities and oil products demand**

Turkey Demand	Tüpraş	STAR	Total	Turkish Market Demand	Balance
LPG	1.1	0.3	1.4	4.1	-2.7
Petchem F.	0.2	2.6	2.8		
Gasoline	6.1		6.1	2.4	**3.7**
Jet Fuel	5.2	1.6	6.8	5.2	1.6
Diesel	10.7	4.5	15.2	26.5	-11.3
Fuel Oil	1.8		1.8	1.3	**0.5**
Bitumen	3.1		3.1	3.1	
Pet coke	0.8	0.7	1.5	4.6	-3.1
Total	~30	~10	~40		

Source: TÜPRAŞ Investor Presentation, March 2020

In 2018, the domestic petroleum market was supplied by 97 distributors and 12,828 fuel stations and the Liquified Petroleum Gas (LPG) market was supplied by 92 distributors and 10,701 autogas stations (PETDER 2018 Sector report, Petroleum Industry Association, 2019). The four largest distributors in the petroleum market (POAŞ, OPET, SHELL, BP) account for 65.6% of the sales and the ten largest for 84.6%. According to analyses at taking into consideration Concentration and Herfindahl-Hirschman Indexes, the petroleum market is in competition but has a tendency to shift to an oligopoly structure (Turkish Petroleum Market Report 2018, EPDK 2019). In latest proceedings the Turkish Competition Board ruled against four companies because of breach of the Competition Law Article 4. According to the Board's decision these companies have to pay 1% of their gross income of 2018 as a fine (Bloomberg.com, 13 March 2020). The oil companies are taking legal action against the decision of the Competition Board.

The Turkish petroleum market prices follow the prices published on the Platts European Market Scan; the changes are reflected not on daily basis but according to a certain formula. The final retail price includes the product price, wholesale margin, income share, distributer and dealer share and taxes. The retail prices differ geographically according to the transportation distances. Table 5.249 shows the components of the final sales price in 2018 in Istanbul's European side.

Table 5.249 **Formation of the average gasoline and diesel prices in 2018 in Istanbul**

		Product Price	Wholesale Margin	Income Share	Distributer, Dealer Margin	Taxes	Final Sales Price
Unleaded 95 Octane	TL/l	2.445	0.077	0.003	0.536	3.158	6.219
	Share	39.31%	1.24%	0.05%	8.62%	50.78%	100%
Diesel	TL/l	2.66	0.037	0.003	0.552	2.549	5.701
	Share	46.66%	0.65%	0.06%	9.68%	42.95%	100%

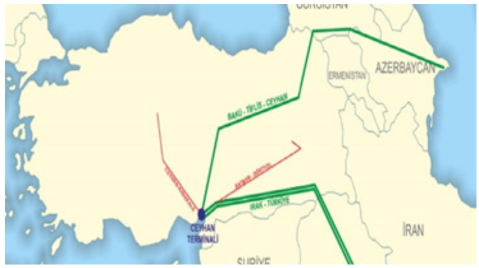
Source: Turkish Petroleum Market Report 2018, EPDK 2019

BOTAŞ and its affiliate BIL operate two domestic and two international crude oil pipelines in Turkey (Map 5.73). The oldest is Batman-Dörtyol pipeline with 4.5 mill t/year capacity, running 511 km from the oilfields of southeast Turkey to the Mediterranean Terminal in Dörtyol. Ceyhan-Kırıkkale pipeline with a capacity of 7.2 mil t/y supplies since 1986 the Kırıkkale refinery with crude oil. The pipeline transported in 2018 4.270 mil t and in 2019 some 4.766 mil t (Botaş, 2020).

The Iraq-Turkey crude oil pipeline was inaugurated in 1976 and the initial capacity of 35 mill t/year was increased in 1984 to 48.6 mill t. With the commissioning of a second line in 1987 the capacity reached 70.9 mill t/year. The pipelines run from the oil fields in Northern Iraq to the Mediterranean harbour of Ceyhan. Since the Gulf War and the UN embargos in 1990's, these pipelines are used in reduced capacity and some sections are damaged. In 2018 the Iraq-Turkey pipeline transported 18.371 mil t and in 2019 some 26.478 mil t to Ceyhan Terminal (Botaş, 2020).

The 1776 km long BTC pipeline stretching from the Sangachal Terminal in the Caspian Sea in Azerbaijan via Georgia to Ceyhan Terminal in Turkey was inaugurated in 2006. The pipeline transports crude oil from ACG fields, condensates from Shah Deniz field and other crude from the Caspian basin. It has a capacity of 50 mil t/year and in 2018 supplied the Ceyhan Terminal with 34.894 mil t and in 2019 with 32.093 mil t (BOTAŞ, 2020).

Map 5.73 **Crude oil pipelines of Turkey**



Source: Ministry of Energy and Natural Resources ETKB, 2020.

During the last years TÜPRAŞ made substantial investments in the development of its transportation fleet. TÜPRAŞ affiliate DITAŞ owns 13 tankers for crude oil and oil products transport. The railway company Körfez Ulaştırma, also a subsidiary of TÜPRAŞ carried with 10 locomotives and 600 cistern wagons 1.8 mil t of products and semi-products in 2019 (TÜPRAŞ Investor Presentation 2020).

(e) Security of supply (+Storage)

Since 1970's Turkey is trying to diversify the oil imports. Realization of Iraq-Turkey crude oil pipeline was an important step in this regard. As an IEA member country Turkey has an obligation to hold emergency oil stocks at least for 90 days of net oil imports. The level of oil stocks is reported monthly to the IEA. Turkey meets its stockholding requirements in the form of "Obligated Industry Stocks" held by the oil industry. Turkey also uses an "Oil Stock Ticket" system, where companies can buy tickets to cover their stockholding obligations from a company holding stocks in excess (International Energy Agency, Energy Market Regulatory Authority, 2020). The oil storage capacity of Turkey is over 15 mill cubic meters. While the majority of stocks are held by refineries, the four refineries of TÜPRAŞ have a total stockholding capacity of over 7 mil cubic meter. The new Star refinery has 1.6 mill t storage capacity. Former ATAŞ refinery near Mersin at the Mediterranean has been transformed into an oil products terminal and serves with a capacity of 577.000 cubic meters as a licensed storage facility (TURCAS, 2020). RUBIS oil terminal in Dörtyol is located close to BOTAŞ Dörtyol facilities and has 650.000 cubic meter storage capacity (RUBIS,2020). Distribution market leader POAŞ and the second largest distributer OPET have 1 mil cubic meters and 1.1 mil cubic meters storage capacity respectively. There are several other storage facilities with smaller capacities.

(f) Planned new projects

Upstream investments will focus on increasing well efficiency in old fields, horizontal drillings of potential unconventional resources in South-eastern Turkey and exploration in untapped regions. Following the discovery in August 2020 of a new major field in the Black Sea, considerable attention will now be given in the drilling of appraisal and development wells and the preparation of the production programme.

The refinery project of Çalık Holding in Ceyhan in the Mediterranean coast unveiled in 2006 has not been realized. At the end of 2016, Turkey's Wealth Fund announced a plan to invest 10 bill $ in a new refinery and petrochemical facilities in Ceyhan. The investment should start after the finalization of the preliminary studies in 2021 (Turkchem, Jan 2020).

There are no new oil pipeline projects in planning.

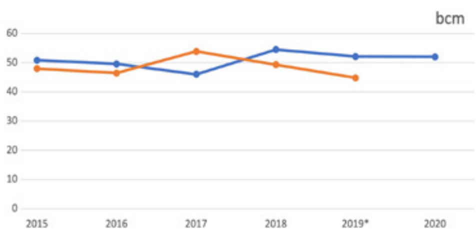
In a second phase of investment Star refinery will increase its initial 1.6 mill t storage capacity to 2.5 mill t until 2021. The storage capacity of 650.000 cubic meter at the RUBIS oil terminal in Dörtyol is planned to be increased to 1 mil cubic meter (RUBIS,2020). TPAO announced a new investment in Batman to add 23,850 cubic meters crude oil storage capacity to the existing 38,478 cubic meters.

Natural Gas

(a) NG Supply and Demand

In 2018, natural gas consumption in Turkey decreased to 49.329 bcm from 53.857 bcm in 2017 by 8.41%. According to preliminary figures the consumption decreased again in 2019 to the level of 44.794 bcm, ie by 9.2% compared to 2018 (EPDK). During 2015-2019 the realized consumption was lower than the yearly forecasts of the Energy Market Regulatory Authority except 2017 (Figure 5.300).

Figure 5.300 **Natural gas consumption forecasts realization for the period 2015-2020**



Source: Energy Market Regulatory Authority, (*) 2019 realization is a preliminary figure subject to change.

Negative economic conditions in the second half of 2018 and the first three quarters of 2019 may be the reason for reduced natural gas consumption, but in 2019 the effects of the mild winter and high electricity generation from renewables and hydropower plants were also accountable. Table 5.250 shows the sectoral breakdown of consumption between 2015-2018.

Table 5.250 **Sectoral breakdown of natural gas consumption in Turkey (bcm)**

	2015	2016	2017	2018
Energy&Conversion	19.313	18.493	22.593	19.933
Industry	13.966	12.600	13.372	11.988
Residential	11.000	11.701	13.515	12.702
Services	3.161	3.123	3.726	4.043
Transport	0.423	0.457	0.529	0.431
Others	0.137	0.107	0.122	0.233
Total	47.999	46.481	53.857	49.329

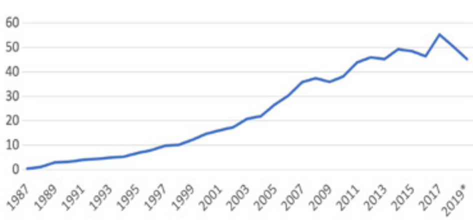
Source: Turkish Natural Gas Market Report 2016, 2017, 2018, Energy Market Regulatory Authority.

In 2018, the Energy & Conversion sector consumed 40% of the natural gas followed by the Household (26%) and Industry (24%) sectors. As the gas distribution network expanded to remote cities of the country the share of the residential consumption surpassed that of industry in recent years.

(b) NG Imports

Turkey's natural gas imports were increasing continuously for 21 years in the period 1987-2008. After that, the upward trend continued, with some fluctuations. The highest level of imports was achieved in 2017 with 55.250 bcm. In 2018, the imports reduced to 50.360 bcm by 8.8%. According to preliminary figures the imports were reduced again in 2019 to 45.207 bcm by 10.2% (Figure 5.301). As mentioned above, the latest decline in 2019 was caused not only by the sluggish economy but also by the weather conditions and historically high generation from hydro and renewables reaching a 44% share of in electricity generation.

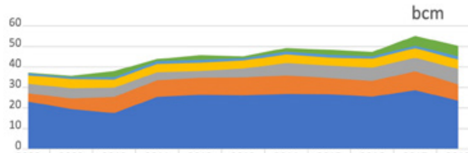
Figure 5.301 **Natural gas imports 1987-2019 (bcm)**



Source: BOTAŞ, Energy Market Regulatory Authority, (*) Preliminary figure may subject to change.

Turkey's main natural gas supplier is the Russian Federation with a share of 47% in 2018 followed by Iran 16% and Azerbaijan 15% (Figure 5.302). All three countries supply their gas by pipelines. The main LNG suppliers of Turkey with long term contracts include Algeria and Nigeria and in 2018 they had a share of 9% and 3% respectively of total gas imports to Turkey. The remaining 10% of supply came in 2018 from spot LNG purchases from eleven countries.

Figure 5.302 **Natural gas imports by country**



2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
0,33	0,78	3,08	1,07	2,46	0,89	1,69	2,49	2,12	4,8	5,14
1,02	0,9	1,19	1,25	1,32	1,27	1,41	1,24	1,22	1,34	1,67
4,15	4,45	3,91	4,16	4,08	3,92	4,18	3,92	4,28	4,62	4,52
4,58	4,96	4,52	3,81	3,35	4,25	6,07	6,17	6,48	6,54	7,53
4,11	5,25	7,77	8,19	8,22	8,73	8,93	7,83	7,71	9,25	7,86
23,16	19,47	17,58	25,41	26,49	26,21	26,98	26,78	25,54	28,69	23,64

Russia Iran Azerbaijan Algeria Nigeria Spot LNG

Source: Turkish Natural Gas Market Report 2018, Energy Market Regulatory Authority, 2019.

90% of Turkish natural gas imports were realized in the framework of long-term contracts from those five countries as shown in Figure 5.302. According to the Natural Gas Market Law BOTAŞ transferred 4 bcm of its Gazprom contract ending in 2022 to four private importers.

Table 5.251 **Turkey's long-term natural gas import contracts**

Country	Importer	Volume (bcm/a)	Duration (years)	Start /End
Algeria LNG	BOTAŞ	4.4	30	1994/2024
Nigeria LNG	BOTAŞ	1.3	22	1999/2021
Russia (Balkan)*	BOTAŞ	4.0	23	1998/2022
Russia (Balkan)*	Other (**)	4.0	23	1998/2022
Iran	BOTAŞ	9.6	25	2001/2026
Russia (BlueStream)	BOTAŞ	16.0	25	2003/2028
Azerbaijan I	BOTAŞ	6.6	15	2007/2022
Russia (Balkan)*	Other (***)	1.0	23	2013/2036
Russia (Balkan)*	Private (****)	5.0	30	2013/2043
Azerbaijan II	BOTAŞ (*****)	6.0	15	2018/2033
Total		**57.9**		

Source: BOTAŞ, GAZID Natural Gas Importers Association.

* Since Jan 2020 via TurkStream,

** Contract transfer from BOTAŞ: 2.5 bcm Enerco, 0.75 bcm BosphorusGaz, 0.5 bcm Avrasya, 0.25 bcm Shell,

*** Batı Hattı,

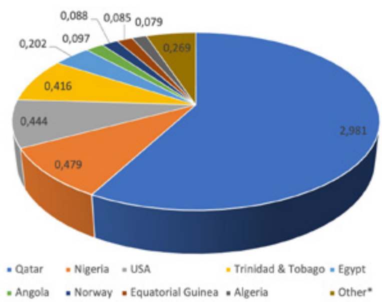
**** 2.25 bcm Akfel, 1.75 bcm BoshorusGaz, 1 bcm Kibar,

***** 1.2 bcm imported by BOTAŞ for SOCAR.

BOTAŞ also did not extend its 6 bcm per year Gazprom contract which ended in 2011. Meanwhile, four private importers signed new contracts of 1+5 bcm ending in 2036 and 2043 respectively.

In 2018, 77.5% of gas imports were via pipeline gas and 22.5% via LNG. In 2017 Turkey became the second largest LNG importer in Europe after Spain. Spot LNG imports to Turkey have grown remarkably over the past years. Table 5.251 shows the distribution of 5.140 bcm spot LNG imports by country of origin in 2018.

Figure 5.303 **Spot LNG imports by country (bcm)**



Source: Turkish Natural Gas Market Report, 2018, Energy Market Regulatory Authority. (*) Re-exports from France and Spain.

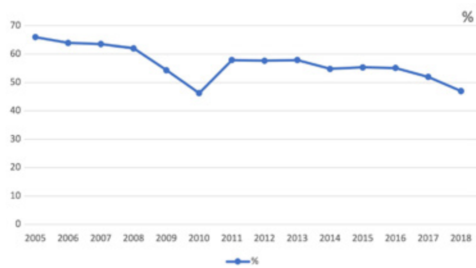
Qatar had the largest share with 58% in spot LNG imports in 2018 followed by Nigeria 9.3%, USA 8.6% and Trinidad and Tobago 8.1%.

In 2007, Turkey started to export Azerbaijani natural gas in the framework of a 0.75 bcm Long-Term Sales Agreement to Greece. After the build-up period 2007-2008 the exports swung around the plateau figure and reached 0.685 bcm in 2018 and 0.776 bcm in 2019. It should be noted that Greece's DEPA has a long-term contract with BOTAS for the import of this gas, which is now characterised as "Turkish Basket" rather than Azeri gas.

(c) Dependence

Despite all the diversification efforts, Turkey is still highly dependent on natural gas imports from the Russian Federation (Figure 5.304). Immediately after the start of natural gas imports from USSR in 1987, Turkey reinforced its diversification efforts by signing long term LNG supply contracts with Algeria and Nigeria and erecting the first LNG regasification terminal in Marmara Ereğlisi. Hence, its 100% dependence on Russian gas was reduced with the first LNG delivery from Algeria in 1994 and from Nigeria in 1999. Despite Turkey starting to receive pipeline gas from Iran in 2001 and from Azerbaijan in 2007, the share of supplies from Russian Federation are still high and account for 66% in 2005. This share has now (2018) been diluted to 47% following the increased spot LNG imports in 2017 and 2018 (see Figure 5.304).

Figure 5.304 **The share of Russian Federation in total natural gas imports**

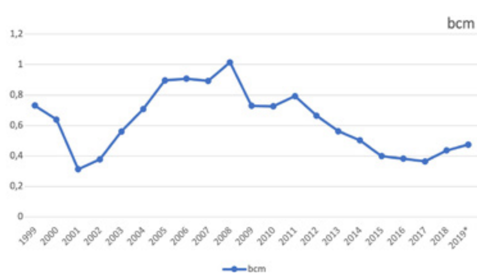


Source: Natural Gas Market 2010 Sectoral Report, Turkish Natural Gas Market Report 2018, EPDK.

(d) Domestic Production and Exploration

Domestic natural gas production reached its highest level in 2008 with 1.015 bcm. In 2018, some 0.436 bcm production covered less than one percent of the country's demand (Figure 5.305).

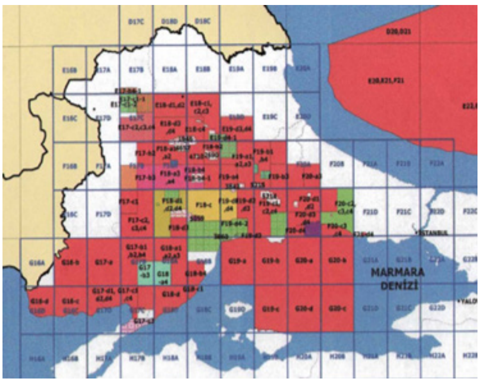
Figure 5.305 **Turkey's domestic natural gas production 1999-2019**



Source: MAPEG, 2019; Natural Gas Market Monthly Report December 2019, EPDK 2020.

Turkey's recoverable natural gas reserves were 3.8 bill cubic meters in 2018; 51% of those reserves belong to the Turkish Petroleum Corporation (TPAO) and the remaining 49% to other natural gas producing companies (MAPEG). It should be pointed out that 98% of the indigenous natural gas has been produced from onshore fields and only 2% from a shallow depth offshore field in the Black Sea coast near Akçakoca. 97.5% of the production comes from Thrace Basin fields in the European part of Turkey (Map 5.74). In 2018, 10 companies holding wholesale licences from EPDK were conducting natural gas exploration and production activities in Turkey. According to EPDK, the largest producer was TPAO with 74.5% followed by Thrace Basin Natural Gas Corporation with 12.3% and Marsa Turkey with 10.2%. According to its latest report, TPAO produced 0.405 bill cubic meters of natural gas in 2018.

Map 5.74 **Exploration and Production licences of the Thrace Basin**



Source: MAPEG

A joint venture formed by Equinor of Norway and Valeura Energy of Canada to explore formations deeper than 2,500 m in Banarlı and West Thrace licence areas drilled their first deep exploration well Yamalık-1, a gas and condensate discovery (Map 5.74). The joint venture partners announced a potential of 286 mcm yet to be proved with appraisal tests. In February 2020 it was announced that Equinor will stop participating in the appraisal program and Valeura will continue (Alliance News, 4 February 2020).

Map 5.75 **Exploration areas of the Equinor-Valeura Energy joint venture**

Source: www.equinor.com

In March 2020, TPAO discovered in the Thrace Basin some 200 mcm natural gas in 2 wells (Daily Sabah, 12 March 2020). Next to the Thrace Basin, TPAO will focus in offshore exploration in its licence areas (shown in red colour) in the Black Sea and in the Mediterranean. In 2018, TPAO conducted two offshore drillings at Kuzey Erdemli-1 shallow water and Alanya-1 deep sea wells in the Mediterranean. Also, it is important to note that in August 2020 a major gas discovery was announced in the Black Sea which is yet to be fully appraised, but apparently is quite sizable and capable of covering a substantial part of Turkey's gas needs over the next 15-20 years.

(e) Infrastructure (Pipelines, Storage)

In 2018 the length of the natural gas transmission grid reached 15,547 km and the distribution network 137,535 km (BOTAŞ, 2018 Natural Gas Distribution Sector Report, Natural Gas Distribution Companies

Association of Turkey GAZBIR 2019). Map 5.76 shows the extensive gas transmission pipeline system of Turkey.

Map 5.76 **Natural gas transmission system of Turkey**

The first international natural gas pipeline connection of Turkey, the **Russia-Turkey Trans-Balkan Pipeline** with an initial capacity of 6 bcm/year was inaugurated in 1987 and runs 845 km from the Bulgarian border via Istanbul, Izmit, Bursa and Eskişehir to Ankara. To allow additional supplies, the capacity of the metering station at the entry point Malkoçlar was increased from 8 to 14 bcm/year parallel to the capacity increase of the pipeline. The line has three compressor stations in Kırklareli, Ambarlı and Eskişehir. After completion of the TurkStream pipeline and its operation in January 2020 Gazprom ceased to supply this line.

The **Blue Stream Pipeline** with 16 bcm/year capacity became operational in 2003 and runs 370 km from Izobilnoye to Djubga onshore in the Russian Federation and 390 km offshore in the Black Sea. In Turkey it continues from the Durusu metering station near Samsun, 501 km via Amasya, Çorum and Kırıkkale to Ankara. The line has one compressor station in Çorum.

The **Iran-Turkey (Eastern Anatolia) Pipeline** with 10 bcm/year capacity has been operational since 2001. It has a length of 1491 km in Turkey from Gürbulak border crossing via Erzurum, Sivas, Kayseri to Ankara. The line has four compressor stations in Doğubayazıt, Erzincan, Sivas and Kırşehir. The measuring station is in Bazargan on the Iranian side of the border.

The **Baku-Tbilisi- Erzurum Pipeline** with an initial capacity of 7 bcm/year became operational in 2007. The 690 km long (South Caucasus Pipeline) is connected with a 226 km stretch from the Georgian border to Erzurum to the Turkish transmission system. There is a metering station at the entry side in Türkgözü and a compressor station in Hanak near Ardahan.

The **Interconnector Turkey-Greece ITG** with a length of 296 km connects the Turkish and Greek transmission networks between Karacabey and Komotini. The pipeline has a capacity of 7 bcm/year and has been in operation since 2007.

The **Trans-Anatolia Pipeline TANAP** with a capacity of 16 bcm/year stretches 1850 km from the Georgian border to the Greek border. It will supply natural gas from Shah Deniz Phase II field to Turkey and other European countries. At the Georgian border it is connected to the extended South Caucasus Pipeline and at the Greek border to the Trans-Adriatic Pipeline TAP. TANAP has two metering stations at the borders and two at the off-take points in Eskişehir and in Thrace. Two compressor stations have been erected near the entry point at the east and at the off-take point in Eskişehir. The pipeline supplied first gas to the Turkish grid in June 2018 and was connected to TAP in November 2019.

The **TurkStream Pipeline** is Turkey's latest major gas pipeline and starts at the Russkaya compressor station near Anapa on the Russian coast and runs over 930 km underwater in the Black Sea to reach the Turkish coast at Kıyıköy northwest of Istanbul. TurkStream consists of two strings each with 15.75 bcm/year capacity. One line is connected to the Turkish grid in Lüleburgaz and delivers the gas previously coming through the Trans-Balkan Line, to Turkey's domestic market since January 2020. The second line is planned to supply South and Central Europe with Russian gas via Bulgaria, Serbia and Hungary. Bulgaria, Greece and North Macedonia are receiving gas from TurkStream since the beginning of January 2020.

Map 5.77 **Natural gas import and export infrastructure of Turkey**

Source: BOTAŞ, revised. UGS: Underground storage facility, LNG: Liquified natural gas regasification terminal, FSRU: Floating storage and regasification terminal.

Turkey's first LNG regasification terminal at Marmara Ereğlisi west of Istanbul owned by BOTAŞ received its first cargo in 1994. After the extension of its jetty in 2019, the terminal received the first Q-Flex LNG carrier (LNG World News, 18 June 2019). In late 2006, private sector investment of the Çolakoğlu Group, EgeGaz LNG regasification terminal in Aliağa north of Izmir went into service. The Egegaz terminal may receive up to Q-Max class LNG vessels. Turkey's LNG infrastructure is summarized in Table 5.252.

Table 5.252 **Turkey's liquified natural gas import infrastructure**

Terminal	Type	Capacity (bcm/year)	Storage capacity (cubic meters)	Send out capacity (mcm/d)
Botaş Marmara Ereğlisi	Onshore LNG	6.0	255,000	37
Egegaz Aliağa	Onshore LNG	6.0	280,000	40
Etki Aliağa	FSRU	5.3	170,000	28
Botaş Dörtyol	FSRU	5.3	263,000	20
Botaş Saros	FSRU	under implementation		

Source: BOTAŞ, Egegaz, Etki FSRU.

The Etki Aliağa FSRU terminal is owned by private sector companies Kalyon (50%), Kolin (30%) and the Iska Group (20%) and started its operation in December 2016 with the chartered FSRU Neptune (former GDF Suez Neptune). In July 2019 the new FSRU Turquoise P with 170,000 cubic meters storage capacity, ordered by the owners of the terminal and built at the Ulsan shipyard of Hyundai in South Korea replaced Neptune. BOTAŞ Dörtyol terminal started its operation in February 2018 with the chartered MOL FSRU Challenger with 263,000 cubic meter capacity.

The Turkish government makes enormous efforts to increase the country's natural gas storage capacities to 11bcm by the year 2023. The first underground storage facility of Turkey is the BOTAŞ Silivri facility and is using the depleted natural gas fields of TPAO in northern Marmara Sea and Değirmenköy. The facility started its commercial operation in 2007 and reached a working gas storage capacity of 2.8 bcm with Phase II investments (Table 5.253). After the commissioning of the third phase investment the capacity will increase to 4.6 bcm. Tuz Gölü underground storage facility is located near Sultanhani in central Turkey.

The facility is using salt caverns in 1100-1400 m depth created by solution mining. The first phase of the project was completed in

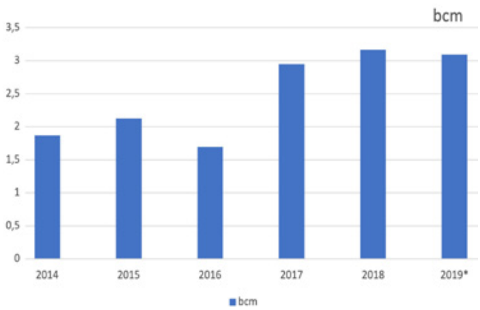
February 2017. With the ongoing second phase investment the storage capacity will increase to 5.4 bcm. The other two envisaged projects are also planned to be implemented in salt domes in the Tarsus area near the Mediterranean Sea and in the Tuz Gölü area, but there is no progress reported as yet.

Table 5.253 **Turkey's underground gas storage capacity**

Location	Capacity (bcm)	Injection rate (mcm/d)	Withdrawal rate (mcm/d)
Operational			
Botaş Silivri Phase II	2.8	16	25
Botaş Tuz Gölü Phase I	0.6	30	20
Under Implementation			
Botaş Silivri Phase III	4.6	40	75
Botaş Tuz Gölü Phase II	5.4	60	80
Planning			
Toren Tarsus Phase I	0.5		24
Çalık Tuz Gölü	1.0	10	20

Turkey's underground storage capacity reached 3.291 bcm in 2018. The LNG storage capacity increased from 0.943 bcm in 2018 to 0.968 bcm in 2019. The year-end natural gas stock in 2018 was 3.167 bcm and in 2019 it reached 3.095 bcm as shown in Fig. 5.306.

Figure 5.306 **End of the year natural gas stock**



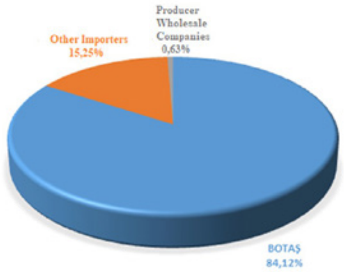
Source: Energy Market Regulatory Authority. (*) Preliminary figure, subject to change.

In 2018, the volume of the stored natural gas in the pipeline system was swinging around 0.250-0.380 bcm (Turkish Natural Gas Market Report 2018, EPDK 2019).

(f) Domestic Gas Market

The basic goals of the Natural Gas Market Law No.4646 of 2001 which are to create competition and avoid dominant market structures have not been achieved yet. The law abolished BOTAŞ's monopoly rights on imports, distribution, sales and pricing. Account separation for trade, transmission and storage was realized. However, an autonomous TSO has not been established yet. BOTAŞ is at the same time TSO and the dominant player in the natural gas market. In 2018, some 84.12% of 50.789 bcm total supply was realized by BOTAŞ. Some 15.25% was realised by other importers and 0.63% by domestic gas producing wholesale companies (Figure 5.307). The wholesale activities are conducted by import licence and wholesale licence holding companies. By the end of 2018 there were 54 companies with a wholesale licence and 11 of them were domestic natural gas producers. In 2018, eight (8) companies with Import licence conducted wholesale activities. Those are BOTAŞ, Shell, Avrasya Gaz, Enerco, Kibar, Batı Hattı, Akfel and BosphorusGaz. From 47 Spot LNG Licence holders 16 realized wholesale activities and only two, BOTAŞ and Egegaz imported spot LNG. The remaining traded with domestic gas.

Figure 5.307 **Share of importers and domestic natural gas producers in total gas supply in 2018**



Source: Turkish Natural Gas Market Report 2018, Energy Market Regulatory Authority, 2019.

After the publication of the Regulation on Wholesale Natural Gas Market in March 2017 and its Operating Procedures and Principles in September 2019 in the Official Gazette, online testing of the Spot Natural Gas Trade System was launched on 1 April 2018. On 1 September 2018, Organized Wholesale Natural Gas Market OTSP at the Energy Exchange in Istanbul (EPİAŞ) started. OTSP allows the users of the

5

natural gas transmission system to trade and to eliminate their imbalances on the basis of a continuous trade (Turkish Natural Gas Market Report 2018, EPDK). Table 5.254 summarizes the first four months' market activities in the OTSP.

Table 5.254 **Organized Wholesale Natural Gas Market**

	Number of offers	Number of matches	Volume of matches (bcm)	Transaction value (mill TL)
Sept-Dec 2018	3,626	2,450	0.587	890.1

Source: Turkish Natural Gas Market Report 2018, EPDK

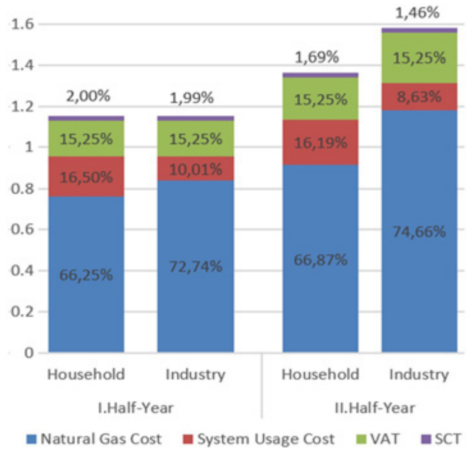
On 5 February 2020, EPIAŞ organized a workshop with the stakeholders to discuss the details like offer type of matching rules, contracts and collaterals of the Natural Gas Futures Market (VGP) to be launched in 2021 (www.epias.com.tr).

Natural gas transmission by pipelines is executed by BOTAŞ. Third party access to transmission network is regulated. The shippers apply to BOTAŞ within the Framework of BOTAŞ Transmission Network Operation Principles. In 2018, 50.97 bcm natural gas was delivered into the transmission pipeline network at 13 entry points and 50.74 bcm was withdrawn from it. In 2018, natural gas was physically transported by 12 entering shippers and 22 exiting shippers in national natural gas transmission network. In addition, there were 30 entering shippers and 27 existing shippers at virtual trade points (Turkish Natural Gas Market Report 2018, EPDK). In 2018, 0.8 bcm was transmitted by 9 licenced LNG transmission companies using LNG vehicles.

In 2018, Natural gas distribution was conducted by 72 distribution companies in 510 cities in 81 provinces. The distribution network reached a total length of 12.875 km steel pipelines, 88,602 km polyethylene pipelines and 36,058 km service lines. 66 million Turkish citizens have access to natural gas and 50.6 million were active consumers.

The total number of customers increased in 2018 to 15.400.892 and the number of eligible consumers to 604.664 (2018 Natural Gas Distribution Sector Report, GAZBIR 2019). The threshold to become an eligible consumer is 75,000 cubic meters. Average Unit Prices of Natural Gas Sold by Distribution and Supplier Companies to Household and Industrial Consumers was in the first half of 2018 around 1.15 TL/cubic meter and increased in the second half of the year to 1.36 TL/cubic meter for households and 1.78 TL/cubic meter for industry. Final sales price includes System usage cost, Value Added Tax (VAT) and Special Consumption Tax (SCT) (Figure 5.308).

Figure 5.308 **Breakdown of Natural Gas Price for Household and Industrial Consumers by Distribution and Supply Companies in 2018.**



Source: Turkish Natural Gas Market Report 2018, EPDK

(g) National NG policy - strategic plan

The basic aspects highlighted in the Strategic Plan 2015-2019 and the 11th Development Plan 2019-2023 are shown below:

- The share of natural gas in electricity generation to be reduced to 20.7% in 2023.
- In order to promote competition cost-based pricing will be adopted.
- In order to increase access to natural gas where appropriate, the transmission and distribution network will be increased.
- Natural gas supply security will be enhanced.
- Underground storage capacity will be expanded to 10 bcm by 2023.

- In order to increase source, country and route diversification FSRU procurement and FSRU network connections will be completed.
- To deepen the trade in Organized Wholesale Market and to start a Futures Market, Derivatives Markets will be established.

(h) Planned new projects

At the time being there is no appetite in the industry to invest further in new natural gas fired power plants.

Transmission and distribution network investments will continue in order to increase access to natural gas. BOTAŞ is investing 2.6 bill TL in new transmission lines until 2023 and 1.5 bill for rehabilitation of existing lines and infrastructure until 2024 (2020 Investment Program). The distribution companies spent 1.7 bill TL for network investments in 2018 and plan to spend a further 1.1 bill TL in 2019 (2018 Natural Gas Distribution Sector Report, GAZBIR 2019). In the coming years, we may expect yearly distribution investments around 1 bill TL. The largest investments will be realized by BOTAŞ in underground storage. Silivri Underground Storage Phase III project, tendered in December 2019, will be finalized in 2022. Total investment of the project is estimated at around 3,5 bill TL. Tuz Gölü Underground Storage Phase II investment project was also tendered in 2019 and has an investment volume of 19.3 bill TL (2020 Investment Program). The project is expected to be commissioned in 2024.

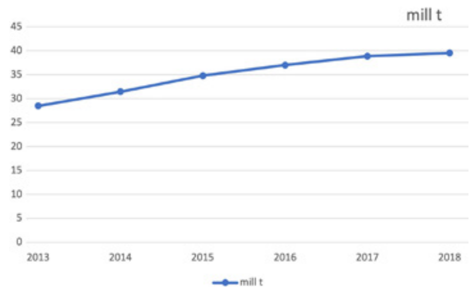
BOTAŞ is investing 450 mill TL for Saros FSRU jetty and network connection until 2021 and will realize remaining investments of 45 mill TL at Dörtyol FSRU until 2021. BOTAŞ is also investing 1.4 bill TL for the procurement of a new FSRU (2020 Investment Program).

Solid Fuels

(a) Supply and consumption

The share of coal in Turkey's primary energy mix in 2018 was 28.4%. In 2018 coal fired power plants generated 113.3 TWh and had a share of 37.3% in the total electricity generation of Turkey. Hard coal, i.e. thermal coal, supply increased from 37.023 Million t in 2016 to 38.879 in 2017 and reached 39.545 Million t in 2018. Turkish hard coal imports in 2018 reached 38.329 million tonnes. Domestic hard coal production in 2018 was about 1.1 million tonnes. Figure 5.309 shows Turkey's hard coal supply since 2013.

Figure 5.309 **Hard Coal Supply in Turkey (2013-2018)**



Source: TTK Turkish Hard Coal Enterprises (2019)

We should note that 60% of the hard coal is used for electricity generation, 15% is used in coke ovens, 14% in industry and the remaining is used for space heating and in other sectors (Table 5.255).

Table 5.255 **Total hard coal supply and sectoral consumption in Turkey (1, 000t)**

	2013	2016	2017	2018
Total supply	28,491	37,023	38,879	39,545
Transformation sector	**17,574**	**24,288**	**25,993**	**29,966**
Electricity generation*	11,777	18,318	19,872	23,825
Coke oven	5,571	5,675	5,797	5,771
Own use + losses	226	295	324	370
Industry	**4,693**	**5,954**	**5,759**	**5.732**
Cement**	2,865	3,877	3,294	2,908
Iron & steel***	1,016	1,228	1,811	1,844
Other industry	812	849	654	980
Other sector**	**6,122**	**6,596**	**6,933**	**3,536**
Statistical difference	101	185	194	312

Source: Ministry of Energy and Natural Resources ETKB, 2019.

* includes heat

** includes ceramic

*** includes nonferrous

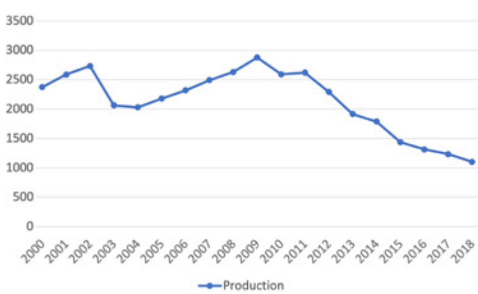
**** includes households, commerce and services.

At the same time, Turkey is a significant lignite producer in its own right. In 2018 lignite demand reached about 81 million tonnes. Nearly 90% of the produced lignite is used on site for power generation, while the remaining is used by industry, for space heating and other users.

(b) Local production and exploration

Despite some 250-300 Million USD yearly subsidies, the hard coal production in Turkey, reached a peak of 4 Million t in early 1980's and since then has been in decline. In 2016 Turkey produced 1.3 Mt, in 2017 1.2 Mt and in 2018 1.1 Mt of hard coal. Fig 5.297 shows Turkey's hard coal production since 2000.

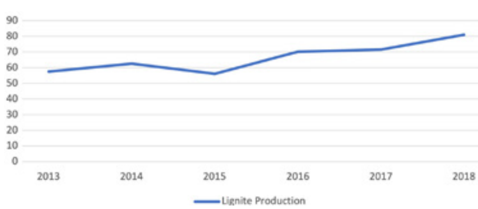
Figure 5.310 **Indigenous hard coal production (1000 t)**



Source: TTK Turkish Hard Coal Enterprises, 2019

Lignite is an indigenous source for electricity generation and plays an important role in Turkey. After Germany, Turkey is the second largest lignite producer in Europe. The lignite production increased from 71.5 million t in 2017 to 81 million t in 2018. (See Fig 5.310)

Figure 5.311 **Lignite production in Turkey (million t)**



Source: TKI Turkish Coal Enterprises, Ministry of Energy and Natural Resources (2019)

Coal exploration activities in Turkey are focused on lignite deposits mainly in central and western Turkey. Intense exploration activities of state agencies between 2005-2015 resulted in an increase of known lignite reserves from 8.3 to 17.9 billion tonnes (Ministry of Energy and Natural Resources, 2019).

(c) Deposits

Turkey's hard coal deposits were discovered in the first half of the 19th century and stretch along the western Black Sea coast from Ereğli in the west over Zonguldak to Amasra. Based on the drilling results up to a depth of -1200 m the total reserves are estimated at 1.5 billion tonnes and the proven reserves 735.9 million tonnes (TTK Turkish Had Coal Enterprises, 2019). The calorific value of the coal varies between 6,200 and 7,250 kcal/kg. The steep bedding of the coal seams and the complex geology of the basin does not allow the mechanized exploitation of coal.

Map 5.78 **Coal deposits in Turkey**

Source: Revised from MTA General Directorate of Mineral Research and Exploration Institute, 2019

The majority of lignite deposits in Turkey are to be found in Western, Central and Eastern regions of the country and also in the Thrace region West of Istanbul (see Fig 26). The lignite reserves are estimated at 17.9 billion tonnes (Ministry of Energy and Natural Resources, 2019). The calorific value of Turkish lignite varies between 1,000 kcal/kg and 5,000 kcal/k. The majority of the reserves (68%) are below 2,000 kcal/kg, 23,5% between 2,000-3000 kcal/kg and the remaining 8.5% between 3,000-5,000 kcal/kg (TKI Turkish Coal Enterprises, 2018).

(d) Core imports

Turkey is one of the largest importers of hard coal in Europe together with Germany and Holland. Turkish hard coal imports increased from 12.9 million tonnes in 2000 to 38.3 million tonnes in 2018 (ETKB, 2019). In 2017 Colombia was the largest hard coal supplier of Turkey with 17.3 million tonnes followed by Russian Federation with 14.4 million tonnes, South Africa 2.2 million tonnes, USA 1.8 million tonnes and Australia 1.1 million tonnes (IEA Coal Information, 2018).

(e) Planned new projects

During the last five years planned coal fired power generation projects have been substantially reduced. Many of them are on hold because of NGO resistance, slowing electricity demand and unfavourable financing conditions, while others because of technical problems related to lignite deposits and specifications.

The only sizeable indigenous hard coal project of Turkey is the Amasra Hard Coal Project of Hattat, holding some 5 million t/a of reserves. With the planned investment of 3.5 billion USD, Amasra is the largest new hard coal project in Europe (Hattat). The project site is on the eastern end of the basin. Since 2005 the company conducted 260 deep development drillings to assist the mine design. Three shafts with 8 m diameter and 570 m, 700 m and 730 m depth were sinked and 25 km of galleries were driven. The project has been delayed considerably because of NGO resistance and court decisions against the planned 2x550 MW power plant to be fed from the mine.

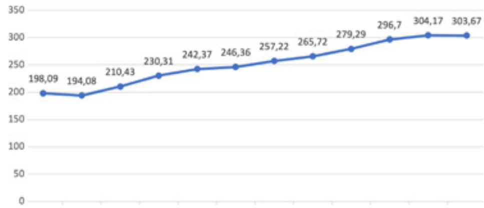
Huge lignite projects like the Afşin-Elbistan (7,000 MW), Konya-Karapınar (5,000 MW) or Afyon-Dinar (3,500 MW) have been postponed. As of January 2020, from 8,200 MW coal fired power plants in the construction phase about 4,960 MW have a realization rate of more than 10% (Energy Market Regulatory Authority, January 2020). We may expect that some of them will be further delayed, and only 3 projects with a total capacity of 1474 MW may be commissioned until 2024. According to Platts, "An estimated 70 GW of planned capacity has either been cancelled or indefinitely postponed since 2009. An additional 33 GW is under various stages of planning, with only 2 GW under construction," (IEEFA, August 26, 2019). Despite these negative developments, one may expect an acceleration of power plant projects with a sustainable economic growth in the coming years.

Electricity

(a) Electricity supply and demand

In 2018, Turkey's gross electricity consumption was 304.2 TWh. This means an increase of 2.5% compared to 296.7 TWh in 2017. Figure 5.312 shows the development of gross electricity consumption since 2008. According to the preliminary figures the gross electricity demand reduced in 2019 to 303.7 TWh due to the slowdown of Turkish economy.

Figure 5.312 **Gross electricity consumption 2008-2019 (TWh)**



Source: TEİAŞ, April 2020, (*) 2019 figure provisional

Ministry of Energy and Natural Resources (ETKB) prepared an Electricity Demand projection for the 2019-2039 period (Table 5.256). The ETKB study was based on three scenarios with yearly average demand growth of 2.90% (low demand, scenario 1), 3.36% (reference demand, scenario 2) and 3.84% (high demand, scenario 3).

Table 5.256 **Electricity demand projection 2019-2039**

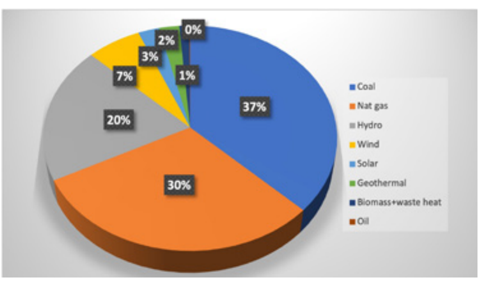
Years	Scenario 1		Scenario 2		Scenario 3	
	TWh	Change	TWh	Change	TWh	Change
2019	313.8	-	315.2	-	316.5	-
2020	327.3	4.3%	329.6	4.6%	332.1	4.9%
2021	340.5	4.0%	344.4	4.5%	348.7	5.0%
2022	353.2	3.7%	359.6	4.4%	366.4	5.1%
2023	366.8	3.8%	375.8	4.5%	385.2	5.1%
2024	380.4	3.7%	392.1	4.3%	404.3	5.0%
2025	392.2	3.2%	406.9	3.8%	422.3	4.5%
2026	404.6	3.1%	421.8	3.6%	440.7	4.3%
2027	416.6	3.0%	436.6	3.5%	458.9	4.1%
2028	428.8	2.9%	451.7	3.5%	477.6	4.1%
2029	441.0	2.9%	466.8	3.3%	496.6	4.0%
2030	453.0	2.7%	481.7	3.2%	514.4	3.8%
2031	464.6	2.6%	496.7	3.1%	534.0	3.6%
2032	476.3	2.5%	511.6	3.0%	552.9	3.5%
2033	487.8	2.4%	526.4	2.9%	571.6	3.4%
2034	499.3	2.3%	541.0	2.8%	590.2	3.3%
2035	510.8	2.3%	557.7	2.7%	608.5	3.1%
2036	522.7	2.3%	570.8	2.7%	627.0	3.1%
2037	534.0	2.2%	585.3	2.5%	644.9	2.9%
2038	545.1	2.1%	599.4	2.4%	662.5	2.7%
2039	556.3	2.1%	613.4	2.3%	679.9	2.6%

Source: Ministry of Energy and Natural Resources.

In 2018 electricity generation increased to 304.8 TWh, up by 2.9% compared to 297.3 TWh in 2017. Coal was the leading fuel with 37.15% participation in the electricity mix, followed by natural gas with 30.34% and hydro with 19.66%. Wind (6.54%), solar (2.56%) and geothermal (2.44%) contributed together with 11.5%. Biomass, biogas and waste heat counted for 1.2% of electricity generation. Figure 5.313 shows the breakdown of electricity generation by fuel type. Hydroelectricity production in 2018 was relatively low compared to long-term average.

According to preliminary figures announced in January 2020 by TEİAŞ, in 2019 the share of hydropower increased to 29%. While the share of coal was stable, the share of natural gas reduced to 19%. The share of remaining renewables including biomass and waste heat increased by 2%. If those figures are verified, Turkey in 2019 realized a historically high generation from hydro and renewables reaching a share of 44% and exceeding by far the target to supply at least 30% of its total electricity from renewable sources by 2023. This is partly due to the highwater income of hydropower plants after the dry year 2018.

Figure 5.313 **Electricity generation by fuel types 2018**



Source: TEİAŞ

Table 5.257 shows the development of total electricity generation, electricity imports and exports and gross demand.

Table 5.257 **Development of electricity generation, import, export and gross demand in Turkey (2008-2019) (TWh)**

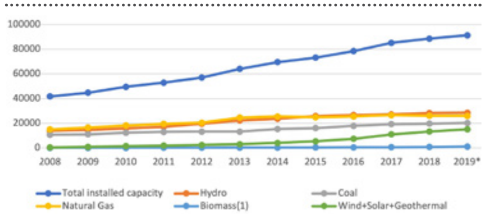
	Total generation	Import	Export	Gross demand
2008	198.418	0.789	1.122	198.085
2009	194.813	0.812	1.546	194.079
2010	211.208	1.144	1.918	210.434
2011	229.395	4.556	3.645	230.306
2012	239.497	5.827	2.954	242.370
2013	240.154	7.429	1.227	246.357
2014	251.963	7.954	2.696	257.220
2015	261.783	7.136	3.195	265.724
2016	274.408	6.330	1.452	279.286
2017	297.276	2.728	3.304	296.702
2018	304.802	2.477	3.112	304.167
2019*	304.252	2.212	2.789	303.674

Development of electricity generation, import, export and gross demand in Turkey (2008-2019) (TWh)

(b) Installed Capacity

In 2018 the installed electricity capacity of Turkey increased by 3.9% and reached a total of 88,550.8 MW (2017: 85,200.0 MW). According to preliminary data, the installed capacity reached in 2019 was 91,267 MW (TEİAŞ, Jan 2020). Figure 5.314 shows the development of generation capacity since 2008.

Figure 5.314 **Installed electricity capacity in Turkey, 2008-2019 (MW)**



Source: Turkish Electricity Transmission Company TEİAŞ, Jan 2020. (*) 2019 preliminary data, (1) includes waste und waste heat.

The installed capacity of *hard coal fired power plants* (including asphaltite) in Turkey increased from 1,986 MW in 2008 to 9,576.4 MW in 2018 and according to preliminary figures to 10,182.7 MW in 2019. Some 8,966.9 MW of this capacity belong to 15 plants commissioned since 2003 and use imported hard coal. Four (4) plants with a total of 810.8 MW capacity are using domestic hard coal and one plant with 405 MW capacity in south-eastern Turkey uses locally produced asphaltite.

Despite grandiose development plans by the government, the *lignite fired* power plant capacity increased modestly from 8205 MW in 2008 to 9456.1 MW in 2018. According to preliminary data, the installed lignite capacity reached 10,101 MW in 2019 (TEİAŞ, Jan 2020).

After an investment boom of about 15 years, the installed capacity of *natural gas fired power plants* has stagnated since 2014. The installed capacity increased from 15,054.8 MW in 2008 to 25,508.1 MW in 2014. In 2018 the capacity was 26.070 MW and in 2019 25.902.3 MW. Increasing generation from renewable resources is certainly one reason, but more important are the economic conditions, like low electricity prices. Some generators have shut down due to adverse conditions, others are kept in stand-by condition under the capacity payments scheme.

Installed capacity of *hydroelectric powerplants* increased from 13,827.7 MW in 2008 to 28,291.4 MW in 2018 and to 28,503 MW in 2019 according to preliminary data (TEİAŞ, Jan 2020). Total installed hydroelectric capacity in Turkey in 2019 was 7860.5 MW, using 558 run of-the river-type generators and the remaining 20.642.5 MW using 124 generators with reservoir.

Akkuyu, the only *nuclear power plant* under construction has been delayed.

Installed capacity of *wind, solar and geothermal* increased from 393.5 MW in 2008 to 13,350.7 MW in 2018 i.e. 33 times. Despite economic slowdown the capacity increased by 13% in 2019 to 15,101.1 MW. The installed capacity of biomass plants increased from 60 MW in 2008 to 738.8 MW in 2018 and according to preliminary data to 801.6 MW in 2019.

c) Planned new capacity – investments

There are 21 licenced natural gas fired power plant projects and cogeneration facilities with 3,535 MW capacity in construction phase. Eleven (11) such projects with an installed capacity of 341 MW, the majority being cogeneration facilities, have a realization rate of over 50% and may be commissioned in 2020 and 2021. Some of the larger generation projects may be further delayed.

Similarly, large lignite power plant projects are either postponed or cancelled. Largest ever planned local hard coal project (2x550 MW) of Turkey near Amasra in the Black Sea coast is still trying to survive. The environmental impact study of the project was cancelled in February 2019 by the High Administrative Court DANIŞTAY according to an appeal by NGO groups. The new integrated study analysing the environmental impact of the power plant together with the coal mine and auxiliary facilities like cinder dump and harbour has been prepared and submitted to the authorities (Enerji Günlüğü). Total investment of the project may reach 3.5 billion US$. The project may be commissioned earliest in 2027.

Other large projects such as the 2x660 MW Emba Hunutlu power plant with a total investment cost of 1.7 bill. US$ is under construction in the Mediterranean coast in Adana province, and will burn imported hard coal (EMBA). The consortium under the lead of Shanghai Electricity Corporation intends to commission the plant in 2023. According to EPDK, there are 12 projects with 8,200 MW licenced capacity in construction phase (Electricity Investment Realization January 2020, Energy Market Regulatory Authority EPDK). Three projects with 1,474 MW capacity may be commissioned until 2024 and the remaining until 2030 or later.

According to State Hydraulic Works DSI, there are 3,636 MW of hydropower capacity in construction phase and 15,995 MW in the planning phase (Table 5.258).

Table 5.258 **Utilization of hydroelectric potential in Turkey**

Status	**Number**	**Installed demand**	**Average generation**	**Share (%)**
Operational	683	28,571	99,628	62.0
Under Construction	47	3,636	11,962	7.5
Planning stage	526	15,995	48,745	30.5
Total	1,256	48,202	160,335	100.0

Source: DSI 2019 Activity Report, 2020.

5

Three large and difficult hydropower projects with a total installed capacity of 2,275 MW are making good progress. The 558 MW Yusufeli Dam on Çoruh river near the Georgian border and Turkey's fourth largest hydropower plant, the 1,200 MW Ilısu Dam on Tigris in Southeast Turkey are being constructed by the public authority State Hydraulic Works DSI. The third project the 517 MW Çetin Dam on Botan river in Southeast Turkey belongs to Limak Holding. All three projects may be commissioned until 2023. From the remaining hydropower projects in different phases of planning 2,000 MW may be realized until 2030 according to the economic growth of the country in the coming years. The 208 MW Zap Hydropower plant in Southeast Turkey with a remaining investment of 0.5 bill TL is planned to be commissioned until 2026. DSI will start with the construction of the 160 MW Silvan Hydropower plant in Southeast Turkey in 2020 and will spent some 0.8 bill TL until 2026.

The Akkuyu Nuclear Power Plant (NPP), the first commercial nuclear power plant to be built in Turkey is currently being implemented in accordance with the Intergovernmental Agreement concluded between the government of the Russian Federation and government of the Republic of Turkey on May 12, 2010. The ground-breaking ceremony of the project took place on April 3, 2018. Akkuyu NPP project with an installed capacity of 4800 MW has four 3+ generation VVER-1200 units. Akkuyu NPP is an AES-2006 serial project based on the Novovoronezh-2 type power plant in Russia (Akkuyu Nükleer A.Ş.). The project has an estimated CAPEX of 20 billion USD and an operating period of 60 years. The project will be developed, financed, operated and decommissioned by Akkuyu Nükleer A.Ş. owned by Rosatom. The Turkish side guarantees the purchase of 50% of the generated electricity within the first 15 years at a price of 12.35 UScents/KWh. Akkuyu nuclear power plant's first unit is expected to generate electricity in late 2023 or in 2024. Construction of the other three units will be completed by 2028.

According to the Turkish Wind Energy Association TÜREB, 25 projects with a capacity of 1,309.8 MW are under erection followed by 35 licenced projects with 1233.6 MW capacity yet to begin, whereas 102 projects with 4,812.6 MW capacity have pre-licence (TÜREB Wind Energy Statistic Report, January 2020). An additional 1,000 MW is assigned to the successful bidders of the second "Regulation on Renewable Energy Resource Areas" YEKA auction. The decision makers acknowledge that the target for 20,000 MW wind capacity in 2023 is not realistic. Some 4,000-5,000 MW of new wind capacity may be installed until 2023, depending on the new feed in tariff applicable from 2021. With a good economic growth and functioning new feed in tariffs Turkey may well achieve the 2023 target of 20,000 MW wind capacity by 2030.

The solar PV investment boom may continue during the 2020-2030 period. We may expect the realization of the 1000 MW first YEKA auction investments until 2023 and planned second 1000 MW YEKA auction investments until 2025. But unlicensed distributed generation on rooftops and facades will continue to be the driving force behind the growth. With new YEKA auctions and/or favourable feed-in tariffs the installed solar PV capacity by 2030 may reach 17,000 MW.

Geothermal electricity generation investments during the past years exceeded government targets. If the present favourable conditions continue, we may expect new investments of about 1,500 MW and an installed capacity which may reach 3,500 MW by 2030.

According to EPDK, there are 48 biomass projects with an installed capacity of 357 MW in the construction phase (Electricity Investment Realization January 2020, Energy Market Regulatory Authority EPDK). We may expect about 700 MW new capacity during 2020-2030 with a total installed capacity of biomass plants reaching 1,500 MW by 2030.

(d) Electricity imports – exports and (f) Cross-border interconnections

Turkey's electricity imports reached its peak in 2014 with 8 TWh, increasing from 0.8 TWh in 2008. Since then, electricity imports have decreased to a level of 2.5 TWh in 2018. According to provisional data from TEİAŞ, the imports reduced further in 2019 to 2.2 TWh. In 2018, 83.3% of the electricity imports were realized from Bulgaria and the remaining from Georgia (16.3%) and Greece (0.4%). In 2018 electricity exports from Turkey were 3.1 TWh and reduced in 2019 to 2.8 TWh (TEİAŞ). About 95% of electricity exports in 2018 went to Greece and the remaining 5% to Bulgaria and Georgia (Electricity Market Development Report 2018, EPDK May 2019).

The Turkish electricity grid is interconnected in the south via a 400 kV line of 400 MW capacity with Syria. In the East there are interconnections with Iraq, Iran, Azerbaijan, Armenia and Georgia. In the West, the Turkish grid is interconnected with the ENTSO-E network via a 400 kV line to Greece and two 400 kV lines to Bulgaria.

Following a trial period since 2010, the permanent parallel operation of Turkey's grid with the ENTSO-E network started in late 2014. In 2015 the export and import capacity to and from ENTSO-E grid has been fixed as 500 MW and 650 MW respectively. Turkish TSO TEİAŞ is co-founder and shareholder of the Coordinated Auction Office in South East Europe SEE CAO. Since October 2015, the cross-border transmission capacity between Greece and Turkey is allocated by SEE CAO on daily, monthly and yearly basis (TEİAŞ).

Electricity Market and Competition

With a 14.80% EÜAŞ had the largest share in electricity generation in 2018, followed by Eren Enerji of the Eren Holding with 5.80% and EnerjiSA, a joint-venture of E-on and Sabancı Holding with 3.93% (Electricity Market Development Report 2018, EPDK May 2019).
An important milestone for the creation of wholesale market mechanisms in the Turkish power sector was the establishment of Day-Ahead Market on 1 December 2011.
Energy Exchange Istanbul EPİAŞ was established in March 2015 and now operates the Day-Ahead Market, the Intra-Day Market and the Balancing Power Market. According to EPİAŞ, the physically settled Power Futures Market is operational since 1 December 2020. In 2018, the Weighted Average Market Clearing Price in Day-Ahead Market increased by 38,65% to 233,101 TL/MWh and the Average System Marginal Price increased by 42,27% to 234,436 TL/MWh compared to 2017 (Electricity Market Development Report 2018, EPDK May 2019). The annual weighted average of the price in the Balancing Power Market was 234,436 TL/MWh in 2018, increased by 42,27% compared to the previous year.

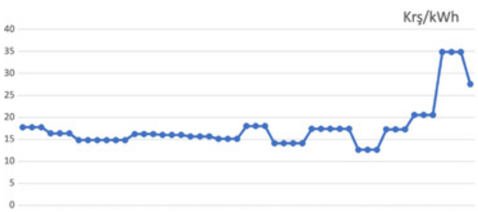
In 2018, the eligible consumer limit was set at 2.000 kWh and accordingly the theoretical market openness rate for demand side was calculated as 92,6%, but actual market openness was 29,6%.

According to analyses based on the Herfindahl-Hirschman Index (HHI) both the electricity generation (1,028) and installed capacity (1,184) lost their oligopoly market character over the years and in 2018 were at a medium intensity level (1,000-1,800). HHI value for the sales of supplier license holders to end-users (494) was at competitive level (Electricity Market Development Report 2018, EPDK May 2019).

(e) Tariffs

Wholesale active electricity tariff of Public generation company EÜAŞ, mainly for sales to distribution companies are quarterly approved by the Energy Market Regulatory Authority EPDK as shown in Fig. 30. Market participants are criticizing this system and argue that the wholesale price of EÜAŞ is not cost-based and distorts competition.

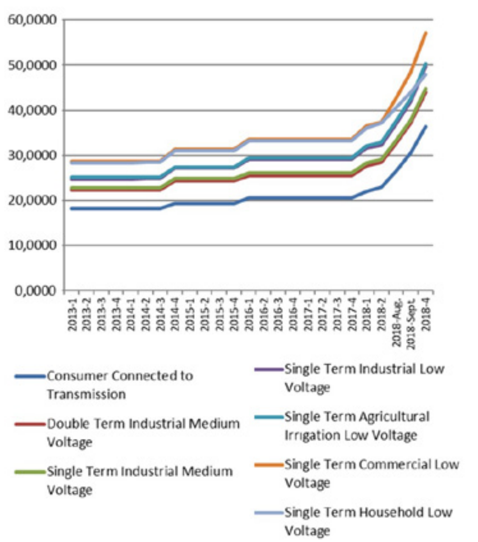
Figure 5.315 **Development of active electricity wholesale price of EÜAŞ (formerly TETAŞ)**



Source: Energy Market Regulatory Authority EPDK, 2020, (100 Krş = 1 Turkish Lira)

Retail Sales Tariff to non-eligible consumers is also approved quarterly by the EPDK and visible at its website. The tariff structure is complicated and contains over one hundred sub-tariffs like low-medium voltage, single-double term, day-night-peak-single time, for industrial, commercial, residential consumers and for agricultural irrigation and lighting. In 2018, the share of energy cost in the final invoice for residential consumer was 54%, followed by 26% network cost, 15% VAT and 5% other taxes, fees and funds.

Figure 5.316 **Development of electricity tariffs before taxes and funds 2013-2018 (Krş/kWh)**



Source: Electricity Market Development Report 2018, EPDK 2019

The Last Resort Tariff is applied to eligible consumers. The tariff aims to encourage eligible consumer with high consumption to purchase their electricity via bilateral contracts from retail companies by applying them higher electricity tariffs.

Transmission System Usage and Transmission System Operating Tariffs for generators and consumers in the 14 regions are prepared by TEİAŞ and approved by EPDK. Final payment of the user to TEİAŞ includes an additional Transmission Surcharge as 0.5% of the applied transmission tariff. Following the preparation of the legal framework in 2016, Turkey in January 2018 introduced an *Electricity Market Capacity Mechanism*. TEİAŞ is making capacity payments to applying, eligible generators based on their fixed cost in order to guarantee security of supply in the electricity market.

(g) Planned new projects

The 2019-2023 development plan includes items regarding the development of the electricity transmission network. Those include the following:

- technical projects to ease the integration of new renewable generation capacities,
- strengthened and more flexible networks,
- increased system reliability,
- increased cross-border interconnection capacities in order to allow more trade,
- realization of Van Back to Back DC interconnection project with Iran,
- realization of a new DC line along the Tortum-Georgia border.

The size of the Turkish transmission network increased to 68,203.8 km in 2018 (40,564.7 km in 1999). Considering the network growth over the last 20 years and increased demand with the integration of new renewable capacities, we may expect that the length of transmission network may reach 90,000 km by 2030.

The number and capacity of substations reached 1826 and 172,276.1 MVA in 2018 (965 and 52,022.6 MVA in 1999). The substation capacity may reach 250,000 MVA in 2030.

Transmission system operator TEİAŞ plans to invest 17.3 bill TL until 2023 mainly in new network and substations.

Operators of the privatized regional electricity distribution companies committed themselves to invest a total of 28.5 billion TL between 2016-2020 to improve the distribution network and to reduce losses. According to the Association of Distribution Services ELDER during 2016-2019 period, the planned investments were widely realized and reached about 26.9 billion TL (Bloomberg 12 Jan, 2020). We may expect that the investments into the distribution networks may continue after 2020. The focus of the investments will be reduction of distribution losses, introduction of smart grids, remote metering and smart electricity meters.

The development plan expects the installed capacity to reach 109,474 MW at the end of 2023. According to this forecast 18,207 MW of new capacity will be added to the system until 2023 during the last four years of the development plan. The development plan and the 2020 Investment programme foresees rehabilitation investments for power plants belonging to EÜAŞ until 2026. Those are the lignite fired 1,440 MW Afşin-Elbistan B power plant (50 mill TL), the 1,800 MW Karakaya hydropower plant (175 mill TL), the 1,330 MW Keban hydropower plant (0.5 bill TL) and the 128 MW Hirfanlı hydropower plants (180 mill TL).

The development plan expects the continuation of efforts for the construction of two more nuclear power plants, additional to the one at Akkuyu.

In February 2020, the Turkish government published a regulation for the grid connection of energy storage systems (Official Gazette, 19.2.2020). With economic incentives yet to be published, the new legislation will primarily support storage projects related to solar PV facilities but also Pumped Storage Hydroelectric plants. EÜAŞ plans to realize the first Pumped Storage Hydroelectricity project in Turkey until 2032. In a preliminary study between 2007-2009 18 potential sites were identified and analysed. In 2010-2011, EÜAŞ and Tokyo Electric Power Corporation conducted the "Study on Optimal Power Generation for Peak Demand in Turkey" and reduced the number of projects using a step-by-step analysis to find the optimum sites. Conceptual design of the best two projects, the Gökçekaya Pumped Storage Hydropower plant (1,400 MW) in Eskişehir province, in Central Turkey and the Altınkaya Pumped Storage Hydropower plant in Samsun province, in the Black Sea Region were realized (YEGM). The projects will use the reservoirs of the existing hydropower plants with the same name as the lower reservoir for the pumped storage facilities. EÜAŞ will start the Gökçekaya project with a budget of 6.3 bill TL in 2020 (2020 Investment Program, YEGM).

It should further be noted that in 2020, DSI will start construction of the 160 MW Silvan Hydropower project in Southeast Turkey and plans to invest 0.8 bill TL until 2026.

Renewables

(a) Overview of the sector's development

According to the National Renewable Energy Action Plan and in compliance with the EU Directive 2009/28/EC, Turkey targets to supply at least 30% of total electricity from renewable sources by 2023. However, this target has already been achieved. The 11th Development Plan sets a target of 38.8% for the share of electricity from renewables by 2023. Since 2010 the country is experiencing a boom in renewables investments starting with hydropower and wind farms. The highest new hydropower capacity with 2,225 MW was connected to the electricity network in 2015 and new wind power capacity with 1,386 MW in 2016. Geothermal power investments surpassed even the expectations of the energy planners. The original target of 600 MW total installed capacity by 2023 was exceeded in 2015. Solar PV installations started to boom since 2015. A record year for solar PV investments was 2017 with 2,588 MW of new installed capacity. Since then, we see a slowdown of renewables investments. There are several reasons for the reduced pace of renewables investments seen currently. NGO resistance against new hydropower development especially in the Black Sea region were followed by protests against new wind farms in the Westcoast. New in the scene are the NGO campaigns against geothermal powerplants in Western Turkey. Regulatory reasons like difficulties to obtain new licences is an important factor. Last but not least, economic factors like weak demand and reduced appetite by the commercial banks for new loans for energy investments also play a role.

(b) Legislation, incentives and national RES policy

Law No. 5346 on "Utilization of Renewable Energy Sources for the Purposes of Generating Electrical Energy" from 2005 and its amendment with Law No. 6094 from 2011 were the main legislation supporting mechanisms for renewables energy investments in Turkey. The renewable energy Law introduced a feed-in tariff system (YEKDEM) to support renewable electricity generation of licenced and non-licenced investments. Depending on the type of renewable energy projects the incentive differs between the Turkish Lira equivalent of 7.3 and 13.3 US cents/kWh (see Table 5.259). These tariffs are applicable for projects starting electricity generation before 31st of December 2020 for a period of ten years.

Table 5.259 **YEKDEM tariffs (US cents/kWh)**

Hydropower	7.3
Wind	7.3
Geothermal	10.5
Biomass	13.3
Solar (PV;CSP)	13.3

According to the Renewables Law an additional mechanism is the locally manufactured equipment support. Regulation on "Local Components in Facilities Generating Electricity from Renewable Energy Resources" from 2016 determines the additional incentives according to the percentage of domestically manufactured components in the relevant equipment. Local components support is applicable for licenced projects starting electricity generation before 31st of December 2020 but only for a period of five years. The premium to be paid for the use of a locally manufactured component varies between 0.4- 2.4 US cents/kWh. The maximum additional incentives are shown in Table 5.260.

Table 5.260 **YEKDEM maximum locally manufactured component support tariff (US$cents/kWh)**

Hydropower	2.3
Wind	3.7
Geothermal	2.7
Biomass	5.6
Solar PV	6.7
Solar CSP	9.2

The new incentive scheme to succeed the expiring YEKDEM system is under preparation. The government is meeting with stakeholders from industry and finance to obtain their views in order to formulate a new feed-in tariff system. Because of the hardship created by the Covid-19 pandemic, the lobby organizations of renewable investors were advocating six months to one-year extension of the existing YEKDEM system. In September 2020, the government extended the deadline to June 30, 2021 (Official Gazette, 18.9.2020).

In October 2016 the government introduced the "Regulation on Renewable Energy Resource Areas" (YEKA) auction model. Different from the YEKDEM, the YEKA model requires the successful bidders of the auctions to use locally manufactured equipment. The bidder offering the lowest electricity purchase price is the winner of the auction. Electricity purchase is guaranteed for 15 years after the signing of the contract. There are different types of YEKA auctions. One YEKA model applied in the first round of auctions allocated 1,000 MW installed capacity to one generator with the condition of investment in equipment production and research & development.

A second round of auction allocated to four successful bidders each with 250 MW installed capacity. A new type of "Renewable Energy Resource Areas" auction with smaller installed capacities called "mini YEKA" is under preparation.

The envisaged auction dates of October 19-23, 2020 have been postponed to January 18-22, 2021 (AA, 8.10.2020). This first mini YEKA auction will take place for 74 locations with solar installed capacities of 10, 15 and 20 MW.

Unlicensed renewable energy generation model contributed heavily to the boom of solar PV investments in Turkey. The legal base of the model was the "Regulation on Unlicensed Generation in Electricity Market" No. 28783 from October 2013 amended with the Regulation No. 30772 from May 2019. Investors with projects up to 5 MW capacity (previous Regulation 1 MW) do not require a production licence or to have established a company.

On February 19, 2020 the Turkish government published a regulation for the grid connection of energy storage systems. With economic incentives yet to be published, the new legislation will primarily support storage projects related to solar PV facilities but also to Pumped Storage Hydroelectric plants. On 8 March 2020, the Energy Market Regulatory Authority issued a regulation amendment dealing with hybrid electricity generation.

The new legislation determines the rules for electricity generation from multiple sources with single licence at one connection point to the network. As of August 1, 2020 a green electricity tariff has been introduced.

(c) Installed capacity per source

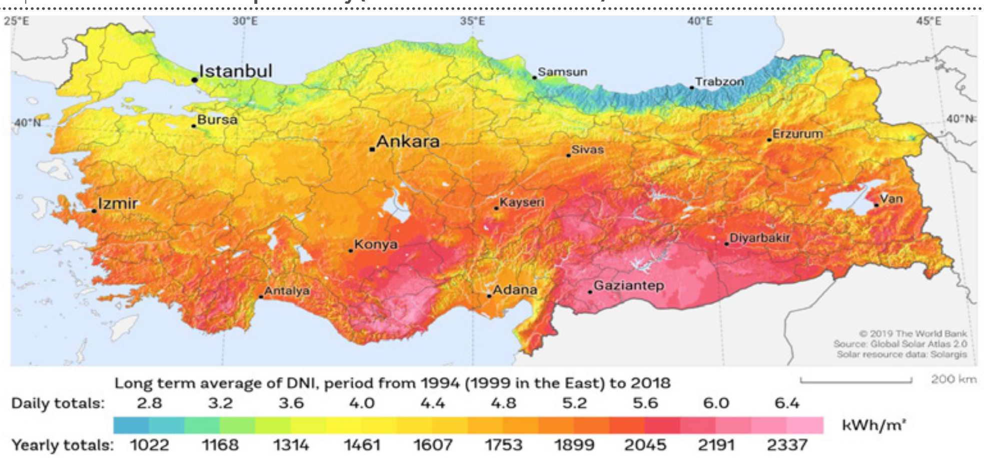
Solar (Thermal, PV)

The total annual insolation time of Turkey is 2,741 hours, and the total incident solar radiation is 1,527 kWh/m2 per year.

Since 1970's solar thermal applications especially solar water heaters are widely used in Western and Southern regions of Turkey. In 2017 Turkey had after China and US the 3rd largest installed solar thermal capacity in the world with 16,287 MWth (Weiss, Spörk-Dür: Solar Heat Worldwide, 2019 Edition). Turkey's solar thermal use increased from 0.843 Mtoe in 2017 to 0.877 Mtoe in 2018 (ETKB, 2019).

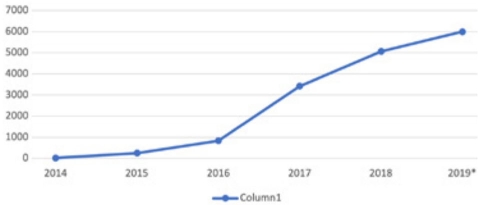
The 2023 goals released in 2010 did not mention a concrete figure for solar at electricity investments but in 2014 with the Renewable Energy Action Plan the target was fixed at 5,000 MW. The Strategic Plan for 2015-2019 set a target of 3,000 MW for 2019. Regarding solar PV installations in 2017, Turkey had the highest growth rate in Europe. The installed capacity increased from 832.5 MW in 2016 to 3,420.7 MW in 2017, a growth rate of 310%. At the end of 2018, the installed solar electricity capacity reached 5,062.7 MW, i.e. a growth of 48% in comparison to 2015 (see Fig. 5.318). According to preliminary figures the growth slowed down in 2019 and the installed capacity reached about 6,000 MW. The bulk of this capacity is stemming from unlicensed, distributed generation facilities, mainly on rooftops.

Map 5.79 **Solar resource map of Turkey (Direct Normal Irradiation)**



Source: Global Solar Atlas,2019

Figure 5.317 **Development of installed solar PV capacity in Turkey (MW)**



Source: Turkish Electricity Transmission Company TEİAŞ, (*) 2019 preliminary figure.

The government and the regulator were rather restrictive concerning the size of licensed solar PV investments. The average installed capacity of licensed generators increased from 17.9 MW in 2017 to 81.7 MW in 2018. The preliminary figure for licensed installed solar capacity for 2019 is 169.7 MW (Energy Market Regulatory Board EPDK, 2020).

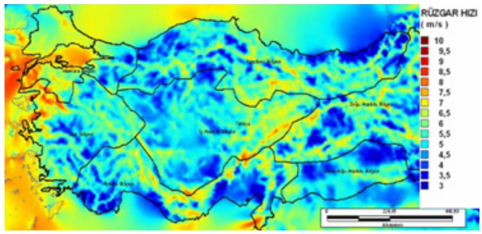
The first YEKA model auction for solar PV was held in March 2017. The consortium led by Kalyon Holding offering 6.99 US$cents/kWh won the bid for 1 GW capacity in Karapinar, Province Konya. In December 2019 Kalyon commenced the manufacturing investment in Ankara as part of the bid. The 400 Million $ facility with an annual capacity of 500 MW PV panels will manufacture solar ingots, wafers, cells and modules (Enerji Portalı, 13.12.2019). After the inauguration of the factory in August 2020, the installation of PV panels started and already in September 4 MW capacity has been commissioned (Milliyet, 28.9.2020).

The second YEKA auction for solar PV to take place in 2019 with a total capacity of 1 GW divided into 500 MW, 300 MW, and 200 MW blocks in three regions has been cancelled. After a legislation amendment, the next round of auctions will be held as mini YEKA on January 18-22, 2021 (AA, 8.10. 2020). The potential investors will bid for capacities between 20 MW in 36 provinces.

Wind

The wind energy potential of Turkey has been estimated as 48,000 MW including 10,000 MW from off-shore areas as shown in Figure 5.318. 61% of this potential has a wind speed of 7-7.5 m/s, 27% 7.5-8.0 m/s and 11% a highest speed at 8-9 m/s (Ministry of Energy and Natural Resources).

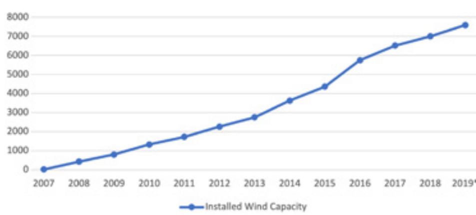
Figure 5.318 **Distribution of annual average wind speed at 50 m height**



Source: Ministry of Energy and Natural Resources.

The 2023 goals released in 2010 were targeting 20,000 MW of installed wind capacity. Later this capacity was also included in the Renewable Energy Action Plan. The Strategic Plan of 2015-2019 set a target of 10,000 MW for 2019. The 2023 target seemed difficult to achieve but even the 2019 target was missed. Installed capacity of wind power plants increased in 2018 to 7,005 MW from 6,516 MW in 2017. According to preliminary figures the installed capacity in 2019 increased to 7,591.2 MW (TEİAŞ, January 2020). Figure 5.319 shows the development of wind power in Turkey between 2007-2019.

Figure 5.319 **Development of installed wind capacity in Turkey (MW)**



Source: Energy Market Regulatory Board EPDK, 2019, TEİAŞ Turkish Electricity Transmission Company, 2020, (*) 2019 preliminary figure.

Until 2014, the majority of wind power generators preferred to sell their electricity to the market. Since then, this trend has been reversed. For 2016, 99% of the eligible wind capacity applied for YEKDEM feed-in tariff system and later all generators followed.

The first YEKA auction in August 2017 for 1.000 MW capacity with manufacturing investment and research & development obligations was won by a consortium led by Siemens-Türkerler-Kalyon with an electricity sales price of 3.48 UScents/kWh. The consortium will build wind farms of minimum 50 MW in five assigned regions: Kayseri-Nigde, Sivas, Edirne-Kirklareli-Tekirdag, Ankara-Çankiri-Kirikkale and Bilecik-Kütahya-Eskisehir. In order to fulfil the local manufacturing requirement, consortium partner Siemens Gamesa finalized a 100 million $ investment in Aliağa near Izmir by the end of 2019. The facility will produce 100 nacelles per year. According to the Izmir Development Agency, with the existing manufacturing facilities of Enercon, General Electric LM wind Power, TPI composites, CS wind and parts suppliers like Ateş Çelik, Dirinler Döküm, Norm Civata and Tibet Makina the Izmir region became a hub of Wind technology (Anatolian Agency AA, 5.11.2019).

The second round of YEKA auction for 4x250 MW capacity was realized in May 2019. The lowest electricity sales price with 3.53 UScents/kWh was offered for 250 MW capacity in Balıkesir province by Enercon. 250 MW capacity in Çanakkale province was won with 3.67 UScents/kWh by Enerjisa. Enercon won the auction for 250 MW capacity in Muğla province with a sales price of 4.00 UScents/kWh. The auction for 250 MW in Aydın province was won by Enerjisa with 4.56 UScents/kWh. The successful bidders are obliged to use equipment with at least 55% local components on average.

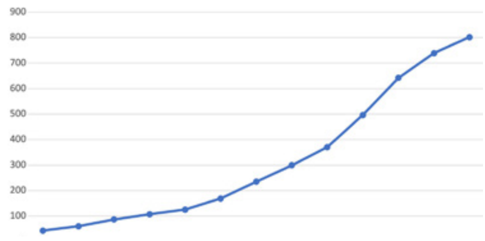
An offshore wind auction announced in 2018 has been cancelled due to feasibility concerns by the stakeholders.

Biomass

According the recently published "Biomass Energy Potential Atlas" Turkey's yearly biomass potential equals to 14.6 Mtoe, including 4.4 Mtoe animal waste, 6.0 Mtoe plant waste, 0.9 Mtoe forestry waste and 3.4 Mtoe municipal waste (Ministry of Energy and Natural Resources, January 2020).

The 2023 goals released in 2010 did not mention a concrete figure for biomass electricity investments but later the National Renewable Energy Action Plan 2013-2023 published in 2014 set a target of 1,000 MW for 2023. The Strategic Plan 2015-2019 set a target of 700 MW for 2019. The installed capacity of generators from biomass exceeded this target and in 2019 reached 801.6 MW (Turkish Electricity Transmission Company, January 2020). After high capacity growths in 2017 (34%) and 2018 (29%), there this is a modest increase of 9% from 738.8 MW in 2018. Figure 5.320 shows the development of biomass electricity generation capacity in the period 2007-2019.

Figure 5.320 **Biomass installed capacity in Turkey (MW)**



Source: Turkish Electricity Transmission Company TEİAŞ, (*) preliminary figure.

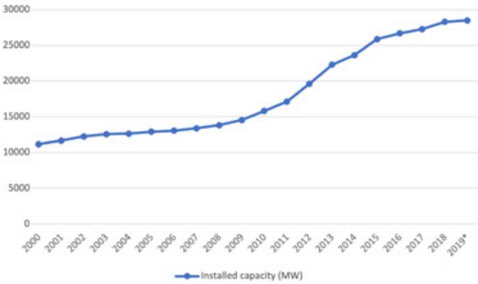
Hydro

State Hydraulic Works DSI estimates Turkey's theoretical hydroelectric potential as 432 TWh/year (www.dsi.gov.tr).Recognising the technical, economic and environmental constrains, an installed capacity of around 40,000 MW may be realized.

Turkish Energy Strategy 2023 targets released in 2010 set the full utilization of hydropower potential as a target. Later, the National Renewable Energy Action Plan mentioned 34,000 MW for 2023. The Strategic Plan for 2015-2019 set a target of 32,000 MW for 2019. Today, the realization is behind those figures. At the end of 2019 Turkey's installed hydroelectric capacity reached 28,503 MW; an increase of less than 1% compared to 28,291.4 MW from 2018 (Turkish Electricity Transmission Company, January 2020).

Figure 5.321 shows the development of the hydroelectric capacity between 2000 and 2019.

Figure 5.321 **Installed capacity of hydroelectric plants in Turkey (MW)**



Source: Turkish Electricity Transmission Company TEİAŞ, (*) preliminary figure.

7860.5 MW of the total hydroelectric capacity in 2019 is installed at 558 run of-the river-type generators and the remaining 20.642.5 MW at 124 generators with reservoir.

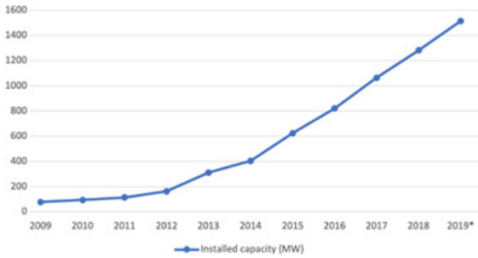
Geothermal

Since 2005 Turkey has intensified its exploration efforts for geothermal resources and has achieved some notable progress. According to the Ministry of Energy and Natural Resources, Turkey's geothermal potential is estimated at 35,500 MWth, and is mainly located in Western Turkey (78%); 10% of the total potential may be suitable for electricity generation. In 2018, some 1.954 Mtoe geothermal energy was directly used for the heating of buildings, in agriculture, in industry and in health tourism and 6.389 Mtoe for electricity generation (ETKB, 2019).

The 2023 Goals released in 2010 were targeting 600 MWe installed geothermal capacity. Later this capacity was revised to 1.000 MW in the Renewable Energy Action Plan. The Strategic Plan 2015-2019 set a target of 700 MW for 2019. The installed capacity of geothermal electricity generators exceeded both targets and at the end of 2019 it had reached 1.514.7 MW spread between 54 plants (Turkish Electricity Transmission Company, January 2020).

Figure 5.322 shows the development of the electric generation capacity from geothermal sources in Turkey.

Figure 5.322 **Installed electricity capacity of geothermal generation plants in Turkey**



Source: Turkish Electricity Transmission Company TEİAŞ, (*) preliminary figure.

Energy Efficiency and Cogeneration

(a) National targets

The first ever regulation for energy efficiency in Turkey was issued on 3 November 1977 and five additional energy efficiency regulations followed until the year 2000. The last one on "Thermal Insulation Rules in Buildings Standard" TS 825 from 2000 was revised in May 2008. The Energy Efficiency Law No. 5627 adopted in 2007 and Energy Efficiency Strategy issued in 2012 were major milestones in the effort to promote efficient use of energy and to reduce the country's energy bill.

The 2015-2019 Strategic Plan of the Ministry of Energy and Natural Resources contains two energy efficiency goals under "Theme 2 - Energy Efficiency and Energy Savings". Those goals are "Goal 4: A Turkey that Uses Energy Efficiently" and "Goal 5: Developed Capacity for Energy Efficiency and Saving". In conformity with the above-mentioned policy documents the National Energy Efficiency Action Plan 2017-2023 was prepared and published in the Official Gazette in 2017. The Action Plan aims towards effective implementation and monitoring of the national energy efficiency actions to achieve the goals. The National Energy Efficiency Action Plan was prepared in compliance with the template set in EU's Energy Efficiency Directive of 2012/27/EU.

The main objective of the National Energy Efficiency Action Plan is 23,9 Mtoe cumulative reduction of Turkey's primary energy consumption in the period of 2017-2023. According to the Ministry of Energy and Natural Resources this means decreasing the primary energy consumption of Turkey by 14 % in 2023 compared to the base case scenario. The plan aims to reduce the energy intensity of Turkey until 2023 by 20% compared to 2011. The Plan foresees 55 actions in 6 areas. Those areas are 1. Buildings and Services Sector, 2. Energy Sector, 3. Transport Sector, 4. Industry and Technology Sector, 5. Agriculture Sector and 6. Cross-cutting (horizontal) Areas. Expected savings, according to the National Energy Efficiency Action Plan by 2033, is 30.2 billion USD (Table 5.261)

Table 5.261 **Total Investments and Projected Savings from Energy Efficiency Projects in Turkey**

Total Investment Required (million USD)							
2017	2018	2019	2020	2021	2022	2023	TOTAL
958	1,279	1,593	1,681	1,748	1,824	1,846	10,928

Energy Savings															
2017		2018		2019		2020		2021		2022		2023		Cumulative	
(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)
577	202	1,630	571	2,493	872	3,378	1,182	4,298	1,504	5,264	1,842	6,261	2,191	23,901	8,365

Energy Savings																					
2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		Cumulative 2017-2033	
(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)	(ktoe)	(m$)
6,261	2,191	6,261	2,191	6,261	2,191	6,261	2,191	6,248	2,187	6,248	2,187	6,248	2,187	6,248	2,187	6,216	2,175	6,216	2,175	86,369	30,228

Source: National Energy Efficiency Action Plan 2017-2023, Ministry of Energy and Natural Resources.

"Buildings' Energy Performance Regulation" and "Green Buildings Regulation" are other recent legislation issued in 2017.

(b) Incentive-based initiatives in the building sector (planned or already in place)

Since 2009 the Ministry of Energy and Natural Resources is supporting energy efficiency projects with incentives and The Ministry of Environment and Urbanization helps to rebuild the old building stock, according to the new regulations.

Efficiency Improvement Project (EEIP)

An industrial company with a minimum of 1,000 toe of annual energy consumption can apply and receive up to 30% grant for an EEIP less than 1 million TL investment.

Voluntary Agreements Program (VAs)

Eligible for such support are companies with a minimum of 1,000 toe of annual energy consumption targeting a minimum of 10% decrease in energy intensity over a three-year period. Companies meeting the agreed target may receive up to 20% of the energy costs during the first year up to 200,000 TL. Companies may apply and receive grants for the EEIP implementation and the Voluntary Agreements at the same time. Despite other interpretations both incentives target the industrial sector.

Transformation of Areas Under Disaster Risk

"Law of Transformation of Areas Under Disaster Risk" (No. 6306) and "Implementation Regulation" also contributes to Turkey's energy efficiency efforts. Large areas of Turkey are earthquake prone. Many of the multi-storey apartment buildings erected prior to the devastating Marmara earthquake of 1999, especially in 1970's are in bad shape and will not survive the next strong earthquake. In the framework of Law No.6306 the Ministry of Environment and Urbanization (MEU) supports an Urban Transformation Process in those areas. The Law encourages property owners to rebuild old risky buildings according to the new building standards and supports them with incentives such as rent allowance, credit facilities, move allowance, tax and fee immunities. The rent allowance to property owners is paid for 18 months and in 2019 amounted to 1,150 TL per month in metropolitan areas like Ankara, Istanbul and Izmir. Urban Transformation Process serves energy efficiency efforts in the buildings sector since the new buildings not only comply with earthquake regulations but also with new energy efficiency standards. According to the MEU from 2012 until August 2019 a total number of 1.166.000 dwellings applied for the urban transformation process and 11 bill TL have been paid to property owners and municipalities.

In 2019 MEU announced the Urban Transformation Action Plan with actions under eight topics. According to the Action Plan, 1.5 mill dwellings (300,000 per year) will be demolished and rebuild until 2023 in line with new standards. Topic 8: 'Financial Support to Urban Transformation with new Grants, Incentives and Loan Facilities' aims at supporting Urban Transformation Projects with higher energy performance targets with additional grants and loans.

(c) EU or non-EU funded energy efficiency programmes in the building sector

Turkish Residential Energy Efficiency Financing Facility TuREEFF

TuREEFF is a programme developed by the EBRD (European Bank of Reconstruction and Development) and supported by CTF (Clean Technology Fund) and the EU that aims to provide finance to residential property owners and investors who want to invest in Energy Efficiency projects in their buildings. Launched in 2015, TuREEFF is combining 270 million dollars of EBRD and CTF loans to promote a transition to Energy Efficiency lending by the local banks. The loan facility is complemented by an EU funded technical assistance program. The interested borrowers receive help from an expert team to develop Energy Efficiency projects and to prepare loan applications free of charge. Financing and advice are available via four participated financial institutions Şekerbank, Işbank, GarantiBBVA and YapıKredi. Until 2019 TuREEFF supported about 4500 projects and achieved 29.3 GWh/year primary energy and 7,393 t/year carbon savings (TuREEFF,2020).

Energy Efficiency in Public Buildings in Turkey

Launched under the German Climate Technology Initiative (DKTI), the project aims to improve the legal, technical and administrative framework conditions for energy efficiency in public buildings in Turkey in order to reduce their energy use and to comply more closely with EU energy efficiency standards. The project is commissioned by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) of Germany. From the Turkish side the Ministry of Environment and Urbanisation (MEU) is the Lead executing agency. The overall term of the project was the period between 2014 and 2020. Since the beginning of the programme a large number of engineers and architects were educated in Train-the-Trainer programmes on Energy Performance Certificates in Turkey and its newly developed software. Several energy audits in public buildings with a focus on public schools were carried out. An innovative combined energy efficiency and earthquake-safety retrofit design for a public school was carried out. An energy efficiency data management system (DMS) for public buildings in Turkey is under implementation. An Energy Efficiency Technology Atlas on energy efficiency products, services, actors in various sectors in Turkey was prepared and launched (GIZ, DKTI Programme for ENERGY EFFICIENCY IN PUBLIC BUILDINGS in Turkey).

Technical Assistance for Renewable Energy and Energy Efficiency Support for the Municipalities and Universities - YEVDES

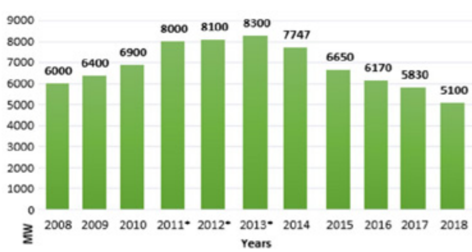
EU founded project IPA 2015 TR2015/EN/07/A1-02/001 with a budget of 4.499.520,00 EUR which was launched in March 2019 and has a duration of 30 months. Next to capacity building, the project will support feasibility studies for renewable energy, energy efficiency audits and R&D projects (YEVDES).

(d) Cogeneration: Regulatory framework, installed capacity

The legal framework for cogeneration or combined heat and power (CHP) facilities in Turkey is set by Law No.3096 enacted in 1984 allowing private companies to generate electricity and the Regulation No. 9799 for "Auto production of Electricity" from the year 1985. After a long period of uncertainties and capacity building efforts, the cogeneration investments started to boom in the second half of 1990's and the installed capacity of 4 MW in 1992 reached 2734 MW in the year 2000 and 6900 MW in 2010.

With the enactment of the new Electricity Market Law No. 6446 in 2013 the Auto producer model was abolished. The existing cogeneration facilities operating under an Auto producer licence had to apply for an Electricity Generation licence but kept their rights from the old law. Four Actions of The National Energy Efficiency Action Plan are now dealing with the promotion of cogeneration facilities. The installed capacity of cogeneration facilities in Turkey reached its zenith in 2013 with 8300 MW. Since then, the installed CHP capacity has been decreasing (Figure 5.323). The reason for this development may be lack of incentives and relatively high natural gas prices compared to electricity prices (Energy and Cogeneration Report 2018).

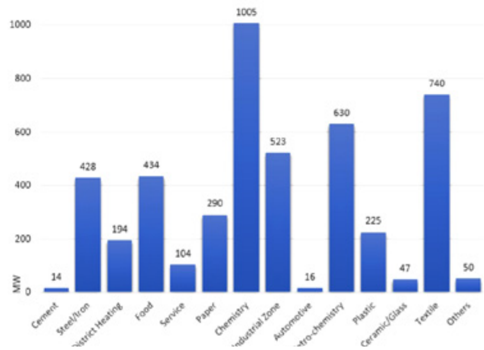
Figure 5.323 **Development of installed CHP capacity in Turkey over 2008-2018**



Source: Energy and Cogeneration Report 2018.

According to a recent legislation change, investors are allowed to build renewable energy and cogeneration facilities up to 5 MW in "non-licensed" status. Nearly half of the licensed cogeneration capacity is installed in chemical, petro-chemical and textile plants followed by food, iron & steel and plastics industries (Figure 5.324).

Figure 5.324 **Installed cogeneration capacity by sector in Turkey**



Source: Energy and Cogeneration Report 2018.

(e) Planned new projects

According to the Turkish Cogeneration Association 38 cogeneration and trigeneration plants with a total installed capacity of 117.9 MW were commissioned in 2019. We may expect a continuation of this trend in the coming years (Kojenerasyon Bülteni). According EPDK, there were 20 cogeneration facilities in the construction phase (Electricity Investment Realization January 2020, Energy Market Regulatory Authority EPDK). Installed capacities and investment in cogeneration plants are counted according to the fuel used.

Energy Investments Outlook

Due to the downturn of the economic growth during 2018-2019 many investors are postponing or cancelling some of their energy projects. They will surely develop new projects when the economy recovers and Turkey returns to high economic growth like in the past.

Oil sector

Turkish Petroleum Corporation TPAO will intensify its offshore exploration investments in the Black Sea and in the Mediterranean in the coming years. On January 31, 2020, TPAO acquired a third drill ship. One of the

5

three drill ships will operate in the Black Sea. In 2018, TPAO realized 688 mil $ investments in Turkey and 863 mil $ abroad (TPAO Sector Report 2018). But not all of this investment went into exploration and production (E&P). There is some correlation between the crude oil prices and oil and gas E&P investments in Turkey (Investment Opportunities in Turkey E&P Sector, 2019). In 2018, with an average Brent price of 71 $/bl E&P investment climbed to 540 mill $. With lower crude oil prices, we may expect a decrease of E&P investments in Turkey. With an average Brent price around 50-60 $/bl for the 2020-2030 period we may expect yearly E&P investments of around 400-500 mill $/year and a total investment of around 5 bill $. Half of this sum may be spent on oil exploration and production and the remaining for natural gas.

The refinery project of Çalık Holding in Ceyhan in the Mediterranean coast unveiled in 2006 has not been realized and a new attempt is not expected any time soon. Turkey's Wealth Fund announced a plan to invest 10 bil $ in a new refinery and petrochemical facilities in Ceyhan in the Mediterranean coast. The investment should start after the finalization of the preliminary studies in 2021 (Turkchem, January 2020).

TÜPRAŞ finalized the large modernization plan at associated investments of its refineries prior to the commissioning of the competitor STAR refinery. In 2019, the company invested 236 mill $. We may expect that the yearly investments will be reduced to 150-200 mill $/year to be invested in digitalization, logistics, sustainability and smaller competitiveness increasing projects. We may forecast a total investment by TÜPRAŞ during 2020-2030 period of some 1.8 bill $. Storage capacity upgrades of the STAR refinery, the RUBIS Dörtyol oil terminal and TPAO in Batman will be realized in coming years. For the 2020-2030 period a total of 300 mill $ in storage and terminal investments can be forecasted for actors other than TÜPRAŞ. Fuel distribution and retail sector is continuously investing in modernization and digitalization; their investment may reach 300 mill in $ in the 2020-2030 period. Total investments in the oil sector for the 2020-2030 period may sum up to 15 bill $.

Natural Gas infrastructure and upstream investments

In the 2020-2024 period BOTAŞ plans to invest 28.8 bill TL in transmission lines, in FSRU and underground storage. The largest investment will be the Tuz Gölü underground storage expansion with 19.3 bill TL. Assuming that the large investments will be realized within the foreseen budget and timeframe, in 2025-2030 period we may expect a reduction of BOTAŞ investments to 10 bill TL or even less. In the 2020-2030 period, we may expect yearly distribution investments around 1 bill TL. The total investments in 2020-2030 may sum up to 48 bill TL + 2.5 bill$ for E&P.

Electricity Generation, Transmission and Distribution

Assuming that the Turkish Electricity Transmission Company TEİAŞ maintains its yearly investment volume we may expect investments of about 40 bill TL in the 2020-2030 period. Public electricity generation company EÜAŞ will mainly invest in the rehabilitation of existing coal and hydro powerplants and start with the erection of the 6.3 bill TL Gökçekaya Pumped storage power plant. We can forecast a total investment of about 10 bill TL until 2030.

Regional electricity distribution companies will finalize their investment commitments in 2020 and reduce their yearly investments. We may forecast a total of 10 bill TL investments until 2030. The focus of the investments will be the reduction of distribution losses, smart grids, remote metering and smart electricity meters. To commission **12 coal fired power plants** with 8,200 MW in construction phase until 2030 an investment of 12 bill $ is needed. Assuming further delays or cancellations due to environmental or financial issues, we may assume a total of 8 bill $ investment in new power plants.

21 natural gas fired power plants and cogeneration facilities with 3,535 MW capacity are in the construction phase. Some of the larger generation projects may be further delayed or cancelled and many new cogeneration projects may be added. An estimated investment of 2.5 bill $ will be needed to commission the natural gas fired power plants and cogeneration facilities until 2030. A total of 8,356 MW **wind projects** including 2,000 MW from 2 YEKA auctions are in different stages of development. If the successor model of YEKDEM feed-in tariff offers favourable conditions to investors and new YEKA auctions take place in the coming years, we may expect about 12,000 MW new wind capacity to be commissioned until 2030 with 11 bill $ investment. In a negative scenario the wind investments may barely reach 9,000 MW until 2030.

The **solar PV** investment boom, driven by unlicensed distributed generation projects may continue. We may also expect the realization of YEKA auction projects. With 11 bill $ investment, the installed capacity may reach 17,000 MW in 2030. If the favourable investments conditions continue, the **geothermal electricity generation** potential of approximately 3,500 MW can be realised until 2030. This will trigger about 5 bill $ investment until 2030.

We may also expect about 700 MW new biomass generation capacity in 2020-2030 period and the total installed capacity of biomass plants may reach 1,500 MW in 2030 with an investment of 2 bill $. Taking 1.2 bill TL yearly hydropower sector investment of DSI as a reference and applying a conservative scenario, we may expect a total investment of the public agency until 2030 of 10 bill TL. This may enable the commissioning of 1,758 MW capacity under construction and to start with new projects of around 600-700 MW. With a reduced risk appetite, the private sector may barely commission 1,878 MW under construction by investing around 4 bill TL until 2030 and increasing the forecast for 2020-2030 period to 14 bill TL.

Akkuyu NPP, the first commercial **nuclear power** plant to be built in Turkey is implemented in accordance with the Intergovernmental Agreement concluded between the Government of the Russian Federation and Government of the Republic of Turkey on May 12, 2010. The project has an estimated CAPEX of 20 billion USD and an operating period of 60 years. The project will be developed, financed, operated and decommissioned by Akkuyu Nükleer A.Ş., owned by Rosatom. The Turkish side guarantees the purchase 50% of the generated electricity within the first 15 years at a price of 12.35 US cents/KWh. Developer of the Akkuyu NPP project tries to fasten the construction of the first unit in order to start electricity generation end of October 2023.

According to their original timetable the first unit would be inaugurated in 2025, followed by remaining units in 2026, 2027 and 2028. In 2019 the foundation of the first unit has been build and some of the equipment like core catcher were delivered to the site. The company started with the site preparation of the second unit during the last days of 2019 (Akkuyu Nuclear A.Ş.). The experts estimate a 15-20% realization of the construction of the first unit by the end of 2019. Based on the construction progress of the first unit in Akkuyu we may expect that remaining investment of the project of around 19 billion USD will take place in the 2020-2028 period.

For the second nuclear power plant project in Sinop, an Intergovernmental Agreement has been signed with Japan in October 2013. Sinop NPP was planned to have ATMEA-1 type reactor design with 4x1120 MW units. Project developers, led by Mitsubishi Heavy Industries finalized their feasibility study in 2018. The studies showed a high cost increase s. The Turkish side cancelled the Sinop NPP project in 2019. A new attempt for the realization of the second nuclear power plant in Sinop with another investor group may start in the coming years but there are no official announcements from the government as yet. But EÜAŞ is planning to realize some minor infrastructure investments for Sinop NPP site for 62.5 mill TL. There are no new developments regarding a third NPP project near İğneada in the Thrace region. Originally Chinese companies were interested in this project.

The total **forecasted energy investment** for the period 2020-2030 in Turkey sums up to 76 bill $ plus 112 bill TL.

References

(1) TÜİK Turkish Statistical Institute, www.tuik.gov.tr

(2) IMF International Monetary Fund, www.imf.org

(3) Strategic Plan 2015-2019, Ministry of Energy and Natural Resources ETKB, 2015.

(4) 11th Development Plan 2019-2023, Turkish Republic Presidential Strategy and Budget Board, July 2019, www.sbb.gov.tr

(5) General Energy Balance Tables 2013, 2016, 2017, 2018, Ministry of Energy and Natural Resources ETKB, 2019.

(6) Turkish Petroleum Market Report 2018, Energy Market Regulatory Authority EPDK, 2019.

(7) General Directorate for Mining and Petroleum Affairs, www.mapeg.gov.tr

(8) TPAO Sector report 2018, Turkish Petroleum Corporation, 2019

(9) Oil & Gas Journal, Oct 19, 2020, www.ogj.com

(10) TÜPRAŞ, www.tupras.com.tr

(11) SOCAR, www.socar.com.tr

(12) TÜPRAŞ Investor Presentation, March 2020, www.tupras.com.tr

(13) PETDER 2018 Sector report, Petroleum Industry Association, 2019

(14) Bloomberg, www.bloomberght.com

(15) BOTAŞ, www.botas.gov.tr

(16) IEA, www.iea.org

(17) TURCAS, www.turcas.com.tr

(18) RUBIS, www.rubis-terminal-tr.com

(19) Turkchem, www.turkchem.net

(20) Turkish Natural Gas Market Report 2016, 2017, 2018, Energy Market Regulatory Authority EPDK

(21) GAZID Natural Gas Importers Association, www.gazid.org.tr

(22) Natural Gas Market 2010 Report, Energy Market Regulatory Authority EPDK, 2011.

(23) MAPEG General Directorate of Mining and Petroleum Affairs, www.mapeg.gov.tr

(24) Natural Gas Market Monthly Report December 2019, EPDK 2020

(25) Alliance News, www.morningstar.co.uk

(26) Equinor, www.equinor.com

(27) Daily Sabah, www.dailysabah.com

(28) 2018 Natural Gas Distribution Sector Report, Natural Gas Distribution Companies Association of Turkey GAZBIR, 2019, www.gazbir.org.tr

(29) LNG World News, 18 June 2019, www.lngworldnews.com

(30) EgeGaz, www.egegaz.com.tr

(31) Etki FSRU, www.etkiliman.com.tr

(32) 2020 Investment Program, Official Gazette No. 31037, 12 February 2020, www.resmigazete.gov.tr

(33) 2018 Hard Coal Sector Report, TTK Turkish Hard Coal Enterprises, May 2019

(34) *2018 Activity Report, TKI Turkish Coal Enterprises, 2019*

(35) *MTA General Directorate of Mineral Research and Exploration Institute, 2019, www.mta.gov.tr*

(36) *Hattat Holding A.Ş., www.hattat.com.tr*

(37) *IEEFA Institute for Energy Economics and Financial Analysis, www.ieefa.org, 2019*

(38) *TEİAŞ Turkish Electricity Transmission Company, www.teias.gov.tr*

(39) *Electricity Demand Projection Report, ETKB Ministry of Energy and Natural Resources, 2018, www.etkb.gov.tr*

(40) *Enerji Günlüğü, 30 April 2019, www.enerjigunlugu.net*

(41) *EMBA, www.embapower.com,*

(42) *TEİAŞ 2018 Activity Report, Turkish Electricity Transmission Company, 2019.*

(43) *Electricity Investment Realization, January 2020, www.epdk.gov.tr*

(44) *DSI Activity Report 2018, State Hydraulic Works, 2019, www.dsi.gov.tr*

(45) *Akkuyu Nükleer A.Ş., www.akkunpp.com*

(46) *TÜREB Wind Energy Statistic Report, July 2019, www.tureb.com.tr,*

(47) *Electricity Market Development Report 2018, Energy Market Regulatory Board EPDK, 2019, www.epdk.gov.tr*

(48) *Bloomberg, 12 January 2020, www.bloomberght.com*

(49) *YEGM Pompaj Depolamalı HES'ler ve Hibrit Enerji Projeleri Konusundaki Çalışmaların Tarihçesi, www.yegm.gov.tr*

(50) *Official Gazette, No. 31248, 18.9.2020, www.resmigazete.gov.tr*

(51) *AA Anadolu Ajansı, 8.10.2020, www.aa.com.tr*

(52) *Global Solar Atlas, 2019, www.globalsolaratlas.info/map*

(53) *Solar Heat Worldwide 2019 Edition, Weiss, Spörk-Dür*

(54) *ETKB, Ministry of Energy and Natural Resources, www.etkb.gov.tr*

(55) *EPDK Energy Market Regulatory Authority, www.epdk.gov.tr*

(56) *Enerji Portalı, 13.12.2019, www.enerjiportali.com*

(57) *Milliyet, 28.9.2020, www.milliyet.com.tr*

(58) *AA Anadolu Ajansı, 5.11.2019, www.aa.com.tr*

(59) *Ministry of Environment and Urbanisation (MEU), www.csb.gov.tr*

(60) *TuREEFF Turkish Residential Energy Efficiency Financing Facility, www.tureeff.org*

(61) *GIZ Deutsche Gesellschaft für Internationale Zusammenarbeit GmbH, www.giz.de*

(62) *DKTI Programme for ENERGY EFFICIENCY IN PUBLIC BUILDINGS in Turkey, www.ee-turkey.org*

(63) *YEVDES, www.yevdes.org*

(64) *Energy and Cogeneration Report 2018, Turkish Cogeneration Association, 2019.*

(65) *Turkish Cogeneration Association, www.kojenturk.org*

(66) *Kojenerasyon Bülteni No.4, Ocak-Mart 2010, ISSN - 2667-5196.*

(67) *Investment Opportunities in Turkey E&P Sector: Özdil, Eser, Regional Oil&Gas Conference 21-22 November 2019, Istanbul, www.petform.org.tr*

5

6

The Peripheral Countries

The Peripheral Countries: Azerbaijan, Austria, Moldova, Ukraine, Italy, Slovakia, Syria, Lebanon and Egypt

There is a group of countries, surrounding our 15 country core group, which we have termed as peripheral countries. These countries are important to the present "Outlook" study as they are associated, in terms of direct energy flows but also trade links, with our specific region. Each of these countries, for different reasons each, is important as they influence energy related developments and issues in the various countries of the broader region. As the name implies these peripheral countries are the ones which literally surround our core region and include Azerbaijan, Austria, Moldova, Ukraine, Italy, Slovakia, Syria, Lebanon and Egypt. There are certain other countries, such as Jordan, which although close and neighbors to our core country group, do not have an immediate bearing in terms of energy impact to our region and hence they have not been included in our present examination.

Following the in-depth analyses in the energy sector of 15 SEE core countries, this Chapter attempts a synopsis of the energy profiles and key energy issues of the aforementioned peripheral countries. The peripheral countries are important for different reasons each. For instance, Syria and Ukraine are countries with substantial geopolitical interest that may affect energy security of supply in SE and Central Europe, while Italy also plays an important role as it acts as an integral part in several regional energy projects, including, for instance, the gas interconnector Greece-Italy (IGI), the Trans Adriatic Pipeline (TAP) and the electricity interconnectors Italy-Montenegro and Italy-Slovenia. Then, we have Azerbaijan, which is a major oil and gas exporter to our 15-country core group and hence merits our attention.

In addition, Azerbaijan's gas flows reached for first time in history the European gas markets from January 1, 2021 through the TAP-TANAP system.

Azerbaijan

According to the IEA (1), Azerbaijan has undergone significant economic transformation since its independence in 1991, with its large oil and gas reserves enabling its strong growth in the 1990s and 2000s. However, heavy dependence on extractive industries has left Azerbaijan exposed to the negative effects of oil price volatility.

From 2013 2017, its GDP growth averaged 1.4% per year, down from 5.5% during 2008 2012. The country's hydrocarbon sector was responsible for the bulk of the decline, as it contributes roughly a third of GDP and makes the bulk of its exports. The 2014/2015 sharp drop in global oil prices and the ensuing decline in oil production pushed this contraction. In addition, the oil price drop led to a decline in remittances from Azerbaijan's hydrocarbon-rich trading partners. These remittances, the bulk of which support the country's rural population, fell by one-third. In 2017, Azerbaijan's GDP barely saw any growth, but 2018 experienced an increase of 1.4%, based on IEA's data. Oil and gas account for more than 90% of Azerbaijan's exports. Oil and gas production increased considerably in the 2000s, following discovery of the Shah Deniz gas field, to reach record levels in 2010. The government and international companies have invested substantially in the energy sector and the construction of several new power plants as well as rehabilitation and modernisation of the gas and electricity networks have improved reliability and security of supply.

Azerbaijan has also strong potential for renewable energy development. The country has excellent solar and wind resources and significant prospects for biomass, geothermal and hydropower. Practical deployment has been limited, however, compared with the scale of the country's available resources and long-term ambitions.

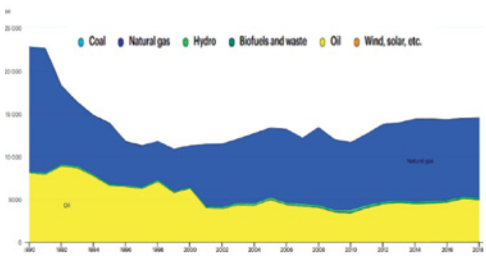
6

Renewables also offer the most prominent low-carbon solution to meeting Azerbaijan's climate targets. The country has committed to reducing its greenhouse gas (GHG) emissions by 35% by 2030, measured from the 1990 base year set in its nationally determined contribution (NDC) under the Paris Agreement, which emphasises the use of alternative and renewable energy sources to achieve this target. Despite widespread privatisation of the economy since the country gained its independence, the energy sector in Azerbaijan remains predominantly government-controlled. Only a handful of small hydropower plants are in private ownership, and they account for less than 1% of electricity generation.

Energy Supply, Demand and Exports

Azerbaijan's energy demand, measured by total primary energy supply (TPES), was 14.4 million tonnes of oil equivalent (Mtoe) in 2018. The country is a major crude oil producer (37.5 Mt, including natural gas liquids in 2019) and a significant producer of natural gas (24.5 bcm in 2019). Azerbaijan was the 24th largest crude oil producer in the world in 2018. Because of this large hydrocarbon production, it has one of the highest energy self-sufficiency ratios in the world: its energy production is more than four times its energy demand. Azerbaijan generates 26 TWh of electricity annually, mostly from natural gas (more than 90% in 2019). Azerbaijan's sole refinery produces 5.8 Mt of oil products from domestic crude oil and NGLs.

Figure 6.1 **TPES by Source in Azerbaijan, 1990-2018**

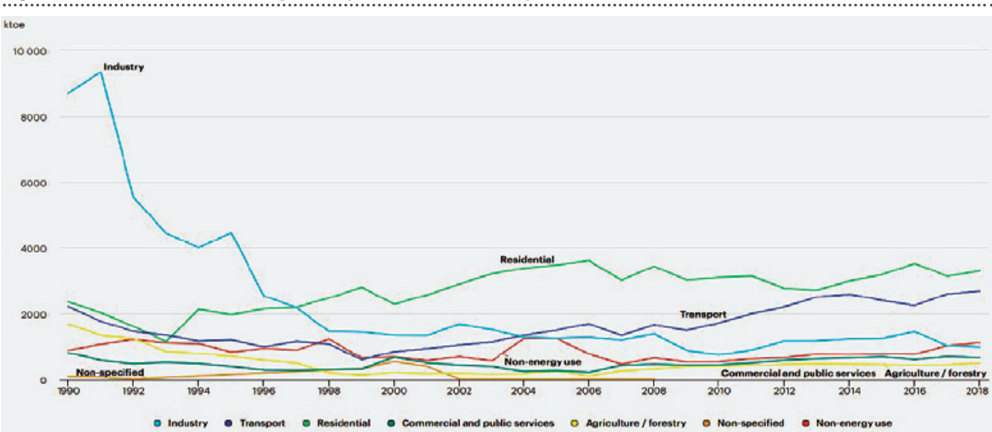


Source: IEA

In 2018, Azerbaijan's total final consumption (TFC), excluding transformation sector, was 9.2 Mtoe. The residential sector is the largest final consumer (3.3 Mtoe in 2018), while transport is the second-largest final-energy-consuming sector (2.7 Mtoe in 2018). Most oil products consumed in the transport sector are produced in Azerbaijan. Despite natural gas having the largest share in the country's TPES, oil is the main fuel in TFC, with a 45% share in 2018. This is because most natural gas is consumed to generate electricity and heat.

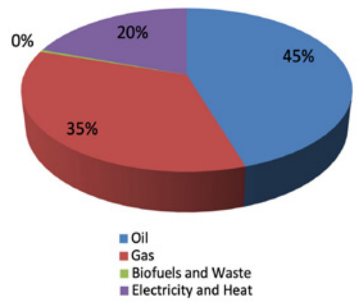
Renewables, including hydro, contributed 2% to total primary energy supply, about 0.4% to total final consumption and 8% (2 TWh) to electricity supply in 2018.

Figure 6.2 **Total Final Consumption by Sector in Azerbaijan, 1990-2018**



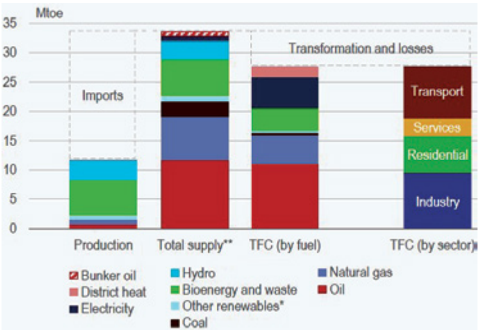
Source: IEA

Figure 6.3 **Total Final Consumption by Source in Azerbaijan, 2018**



Source: IEA

Figure 6.4 **Overview of the Austrian Energy System by Fuel and Sector, 2018**



Source: IEA

As of December 31, 2020, Azerbaijan started exporting gas to the European Union via the TANAP pipeline to Turkey and the Trans Adriatic Pipeline (TAP), as the region seeks to diversify energy supplies away from Russia. More specifically, gas pumped from the giant Shah Deniz 2 field in the Caspian Sea began flowing into Italy, Greece, and Bulgaria on December 31, Azerbaijan's state energy company SOCAR said in a statement. Azerbaijan already supplies gas to Turkey and aims to supply European gas markets with 10 bcm of gas per year. In general, Azerbaijan is an exporter of crude oil and a net exporter of petroleum products, natural gas and electricity.

Austria

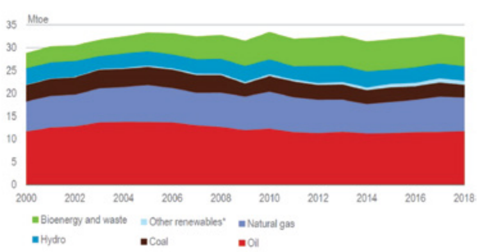
According to the IEA (1), Austria is heavily dependent on energy imports, despite its large hydro and bioenergy resources. Its average self-sufficiency level has been 36% over the past decade, characterised by a high and continuously increasing share of renewable energy sources. Total primary energy supply (TPES) was 32.8 million tonnes of oil equivalent (Mtoe) in 2018, of which fossil fuels accounted for around two-thirds and renewables for the remaining third (see Figure 6.4).

Total final consumption (TFC) by fuel was 27.6 Mtoe in 2018, of which oil accounted for 40%, electricity for 20%, natural gas 18%, and bioenergy and waste 14%. By end-use sector, TFC is split between the industry sector, transport and buildings (the residential and service sectors including agriculture), with roughly a third of consumption each. Renewable energy is especially large in electricity generation, where hydropower accounts for over half of the total, with continuously increasing shares of wind and solar.

Primary Energy Supply

In 2018, oil accounted for 36% of TPES, natural gas for 23% and coal for 8%. The remainder was low-carbon energy sources, in particular bioenergy and waste, which accounted for 19% of TPES, and hydro with 10% (see Figure 6.5). Small shares of solar, wind and geothermal accounted for the remainder.

Figure 6.5 **TPES by Source in Austria, 2000-2018**



Source: IEA

Since 2000, there has been a continuous shift to renewable energy sources. Among renewables, bioenergy and waste increased the most in terms of absolute numbers, from 3 Mtoe in 2000 to 6 Mtoe in 2010. Since then, however, the share of bioenergy and waste supply has been stable. Wind and solar energy have increased about threefold over the last decade, and their share of TPES grew from below 1% in 2008 to nearly 3% in 2018. Meanwhile, coal supply fell by 28%, from 3.8 Mtoe in 2008 to 2.7 Mtoe in 2018. Oil supply decreased by about 7%, from 12.7 Mtoe in 2008 to 11.8 Mtoe in 2018, but remained the single largest fuel in TPES, while natural gas supply fluctuated between 6.4 Mtoe and 8.1 Mtoe during the same period, based on IEA's data.

Energy Production and Self-sufficiency

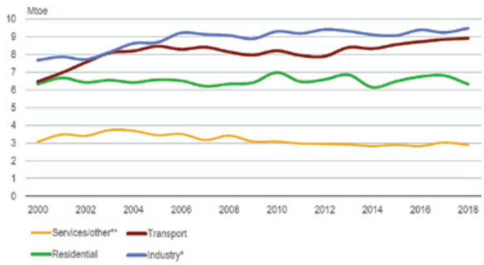
In 2018, domestically produced energy was 11.7 Mtoe, of which 51% was bioenergy and waste, followed by 28% of hydro. Fossil fuels accounted for only 13% of domestic production in the same year and the trend is declining. Crude oil production fell by 30%, from 1.0 Mtoe in 2008 to 0.7 Mtoe in 2018 . Similarly, domestic natural gas production fell by 30% (32% in volume terms), from 1.2 Mtoe in 2008 to 0.9 Mtoe in 2018, following a peak in 2012 at 1.5 Mtoe.

Energy Consumption

Energy consumption has been on an upward trend in the industry and transport sectors since 2014, while fluctuating in the residential sector (see Figure 6.6). Austria will likely miss its total final energy consumption target for 2020. TFC increased from 26.4 Mtoe in 2014 to 27.9 Mtoe in 2017, which was the highest consumption level in Austria so far. In 2018, TFC fell slightly to 27.6 Mtoe, due to a drop in the residential sector after a previous increase. Consumption in the residential sector depends largely on the need for heating, and it has fluctuated between 6 Mtoe and 7 Mtoe over the last decade.

The transport sector has seen the largest increase in recent years, from 7.9 Mtoe in 2012 to 8.9 Mtoe in 2018. Industrial consumption, including non-energy consumption, has also increased, although slowly, to a new high at 9.5 Mtoe in 2018. Meanwhile, consumption in the service sector has remained stable at around 3 Mtoe in the last decade.

Figure 6.6 **Total Final Consumption by Sector in Austria, 2000-2018**



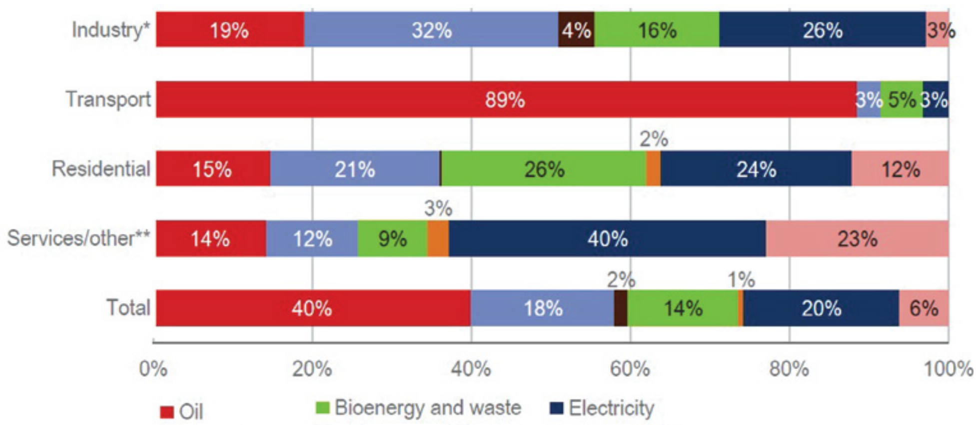
Source: IEA

Fossil fuels accounted for 60% of TFC in 2018, as shown in Figure 6.7. The transport sector is highly dependent on oil, which accounted for 89% of the sector's total energy consumption. The industry sector is also heavily dependent on fossil fuels, which supplied 55% of total fuels consumed in industry, including for non-energy purposes. Of this, natural gas accounted for the largest portion, with 32%, followed by 19% of oil and 4% of coal. Almost all coal consumption in Austria is in the industrial sector. Electricity, bioenergy and waste are also important energy sources in industry.

In the residential and service sectors, energy is mainly used for heating or electrical appliances. Both the residential and the service sector use natural gas and oil for heating purposes, but bioenergy is the largest source of heat in residential buildings, while district heating the largest source of heat in the service sector.

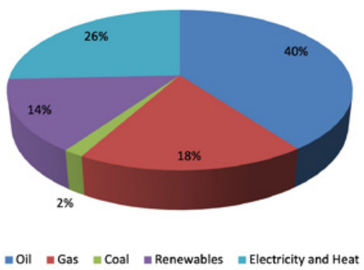
1 These numbers are in energy terms for the production of crude oil, including natural gas liquids and feedstock.

Figure 6.7 **Total Final Consumption by Source and Sector in Austria, 2018**



Source: IEA

Figure 6.8 **Total Final Consumption by Source in Austria, 2018**



Source: IEA

As far as energy flows are concerned, electricity in Austria is exchanged freely between Germany, the Czech Republic, Switzerland, Hungary, Slovenia and Italy, with Austria being a net importer of electricity. In addition, Austria's gas market depends largely on imports from other countries, such as Russia, Norway and Germany. This is clearly reflected in the ratio of the country's annual gas production of 0.9 Mtoe and net imports of 6.5 Mtoe, amounting to a gross consumption of 7.8 Mtoe in 2018. In 2018, a total of 9.1 Mtoe of crude oil was processed at a capacity utilization of 91%. 7% of the crude oil processed came from domestic sources and 93% from imports, mainly from Kazakhstan, Libya and Iraq.

Moldova

According to the IEA (2), Moldova lacks energy resources and thus, it is almost wholly dependent on fossil fuel and electricity imports: only 20%[2] of its energy demand was met by domestic sources in 2018. Natural gas, which serves most of its energy needs, was entirely imported from Russia via Ukraine up to the end of 2014. In August 2014, the Iasi-Ungheni gas interconnector between Romania and Moldova was commissioned, and became operational in 2015. Once at full capacity in 2020, the pipeline is expected to supply almost all the gas Moldova consumes, but not that of the Transnistria region. The government also plans to diversify the energy mix with more renewable energy. As expansion requires significant investment in the medium and long term, progress will depend on the country's ability to attract funds. The development of uncontrollable renewables, such as wind and solar, will be limited by the balancing capabilities of the Moldovan power system.

Moldova has been a member of the Energy Community since 2010 and signed an Association Agreement with the European Union on June 27, 2014. It therefore had until December 2017 to make its legislation conform to the EU acquis communautaire, which is the core EU energy legislation related to electricity, oil, gas, the environment, competition, renewables, efficiency and statistics.

[2] This figure represents the IEA Secretariat's estimates for the districts from the left side of the river Dniester and municipality of Bender.

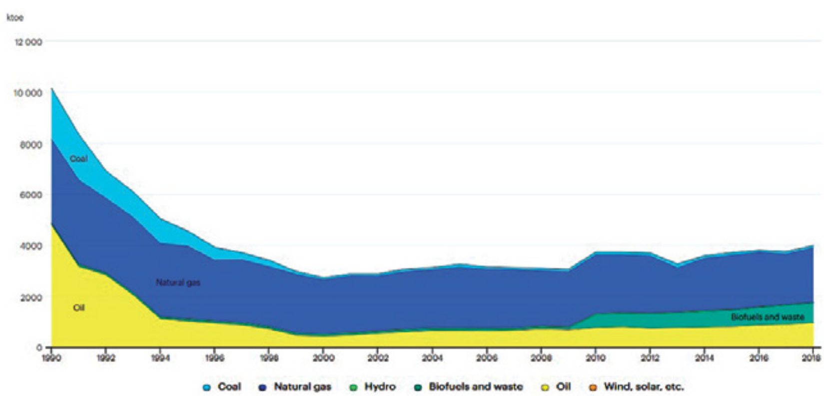
Moldova also plans to fully synchronise its electricity network with the European Network of Transmission System Operators for Electricity (ENTSO-E) to connect to the European electricity market. Regional energy co-operation with Caspian and Black Sea countries and the European Union follows the framework of the Baku Initiative, which aims to facilitate the progressive integration of the region's energy markets into the EU market, as well as the transportation of substantial quantities of Caspian oil and gas towards Europe. Moldova also participates in the Eastern Partnership, a joint initiative involving the European Union, its member states and the post-Soviet states of Armenia, Azerbaijan, Belarus, Georgia, Moldova and Ukraine; it provides a venue for discussions on trade, economic strategy and travel agreements, as well as an energy security platform. In addition, the European Neighbourhood Policy promotes bilateral co-operation between the European Union and Moldova in line with the Partnership and Co-operation Agreement, which includes energy co-operation. Based on IEA's data[3], Moldova consumes around 4 million tonnes of oil equivalent (Mtoe) of energy per year (4.1 Mtoe in 2018), comparable to energy consumption in Luxembourg.

Energy Supply, Demand and Imports

Moldova's energy self-sufficiency is very low, among the lowest in the world. Around 20% of its energy demand is covered by domestic production, consisting almost fully of solid biomass; total domestic energy production was 0.82 Mtoe in 2018, of which 0.79 Mtoe solid biofuels. Natural gas accounts for more than half of Moldova's total primary energy supply (53% in 2018), oil roughly a quarter (23% in 2018) and solid biomass one-fifth (19% in 2018). Most natural gas is used for electricity and heat generation[4] , whereas oil is the most important energy source for final consumers, mainly used for transportation. The residential sector is the largest energy consuming sector (around 1.4 Mtoe in 2018), solid biofuels covering over 50% of the sectorial consumption. Transport sector is the second-largest energy consumer (around 0.7 Mtoe) and the main driver in oil consumption growth.

Furthermore, Moldova needs to import most energy commodities to meet domestic demand. All natural gas consumption (2.1 Mtoe or 2.9 billion cubic metres (bcm) in 2018) is met through imports, mainly from Russia. Imports cover 99% of Moldova's oil consumption (1.0 Mtoe in 2018, of which almost 80% diesel and motor gasoline). All coal consumed must be imported as well (0.09 Mtoe in 2018).

Figure 6.9 **TPES by Source in Moldova, 1990-2018**

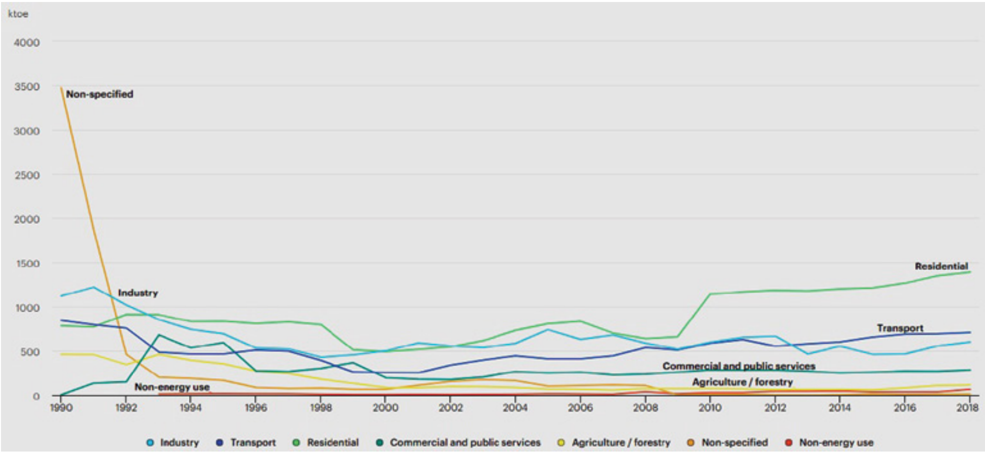


Source: IEA

[3] Official figures on natural gas imports, natural gas inputs to power plants, electricity production and consumption are modified by the IEA Secretariat to include estimates for supply and demand for the districts from the left side of the river Dniester and municipality of Bender.

[4] Natural gas is used at MGRES power plant, which is situated in Transnistria. The Moldovan government procures electricity directly from the plant.

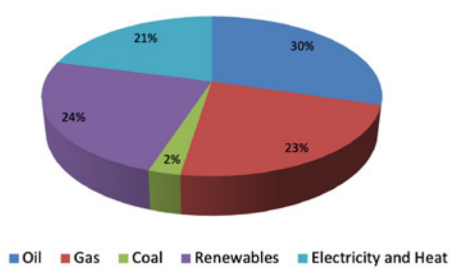
Figure 6.10 **Total Final Consumption by Sector in Moldova, 1990-2018**



Source: IEA

Renewables represent 20% of Moldova's energy mix, consisting almost fully of solid biofuels (19% in 2018). 6% of electricity generation comes from renewable sources (hydro, wind, solar PV), based on IEA's data.

Figure 6.11 **Total Final Consumption by Source in Moldova, 2018**



Source: IEA

Ukraine

Located at the crossroads of the European Union, Russia and the Black Sea and Caspian regions, Ukraine has abundant mineral resources including oil, natural gas and coal, and large hydro and biomass potential. With its considerable population and high energy consumption, it is one of Europe's largest energy markets. It is also the country that transits the most natural gas in the world, playing a key role in delivering Russian gas to European markets.

Deep structural changes and an overall decline in economic activity caused total gas consumption to fall from 50.4 billion cubic metres (bcm) in 2013 to 29.8 bcm in 2019 and caused natural gas's self-sufficiency[5] to increase from 43% to 69%. Also, during this period, a dispute with Gazprom over the price of gas and its transit through Ukrainian territory prompted Ukraine to source its imports from European suppliers instead, so Gazprom's share in total gas imports shrank from 92% in 2013 to 0% during 2016 2019. Coal production and transportation have been severely disrupted in the Donbass region, as has electricity generation from co generation plants[6] , especially in conflict areas.

Energy Supply, Demand and Imports

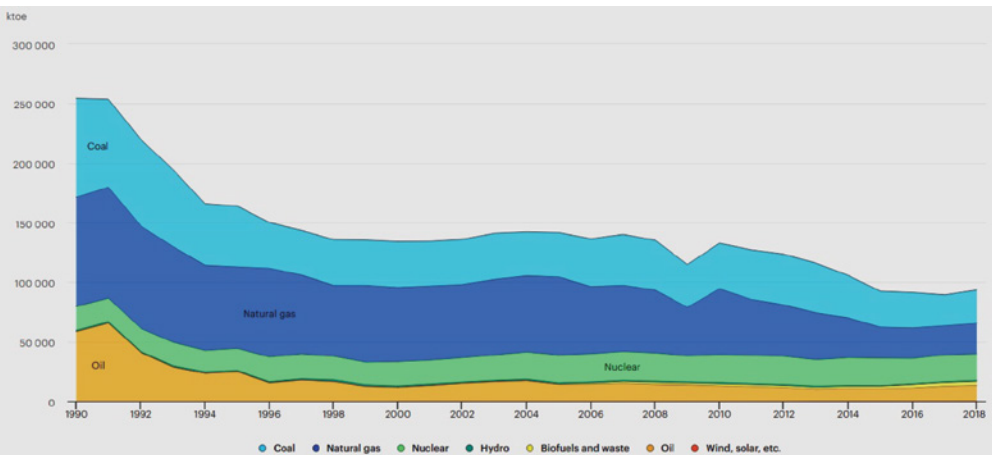
According to the IEA (3), Ukraine produces all fossil fuels (in 2018: 14.4 Mtoe of coal, 16.5 Mtoe of natural gas and 2.3 Mtoe of crude oil), but in quantities insufficient to meet total energy demand. Still, nearly 65% of Ukraine's total energy demand is covered by domestic

[5] Excluding the temporary occupied Autonomous Republic of Crimea, Sevastopol-City and parts of Donetsk and Luhansk regions.
[6] Domestic production/TPES.

production. This high self-sufficiency level is explained by nuclear power generation, as Ukraine is the world's seventh-highest producer (83 TWh in 2019). Over half of the country's electricity is produced with nuclear power and Ukraine and Armenia are the only EU4Energy countries that produce nuclear energy. Ukraine is the top energy consumer among EU4Energy focus countries. Its primary energy supply was 93 Mtoe in 2018, corresponding to around 90% of Poland's consumption.

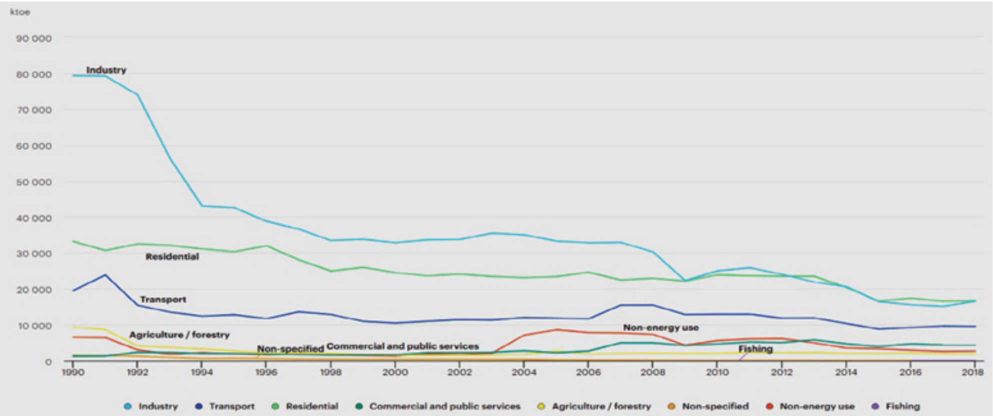
In 2018, Ukraine's total final consumption (TFC; excludes transformation sector) accounted to 51.5 Mtoe. Industry is the largest final energy consumer (19.1 Mtoe in 2018). The residential sector is second (16.7 Mtoe), with households being the major users of natural gas (8.7 Mtoe in 2018). The share of coal in final consumption is very small (12%) because most of the coal consumed in the country is used to produce electricity and heat. Ukraine depends on imports for around 83% of its oil consumption, 33% of its natural gas and 50% of its coal. In 2018, Ukraine imported 8.5 Mtoe (10.6 bcm) of natural gas, 13.8 Mtoe of coal and 10.4 Mtoe of oil products. Belarus is Ukraine's main supplier of refined products. Ukraine's energy mix is relatively diversified, with no fuel representing more than 30% of the energy mix. In 2018, the share of coal (the country's primary fuel) dropped to 30%, followed closely by natural gas (28%) and nuclear (24%). Renewables accounted only for 5% of the energy mix in 2018, and for 9% of electricity generation (13.4 TWh in 2019).

Figure 6.12 **TPES by Source in Ukraine, 1990-2018**



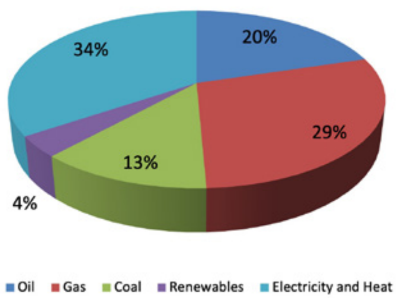
Source: IEA

Figure 6.13 **Total Final Consumption by Sector in Ukraine, 1990-2018**



Source: IEA

Figure 6.14 **Total Final Consumption by Source in Ukraine, 2018**



Source: IEA

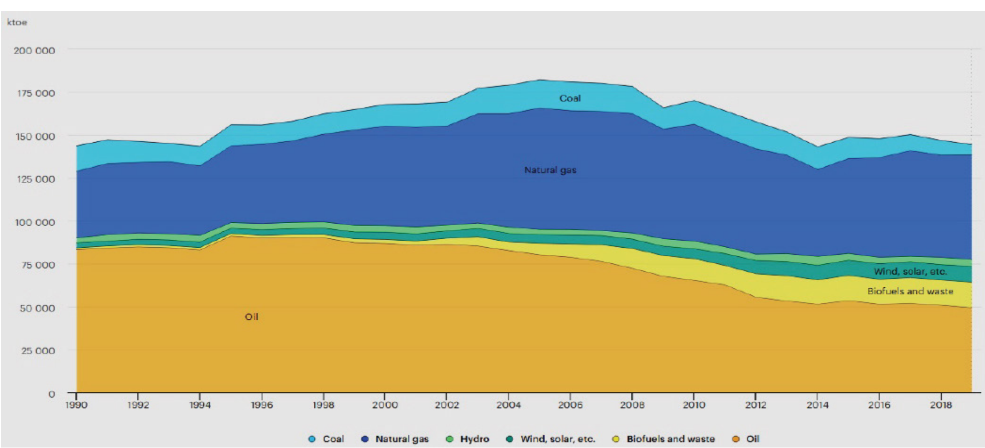
Italy

The last few decades have seen profound changes being made to the Italian energy system, in which natural gas first of all established itself as a prime energy source, followed by (from 2005 onwards) a marked rise in renewable energy sources, in particular in the electricity sector, and a steady reduction, on the other hand, of petroleum products. These developments are the results of both policies aimed at significantly reducing greenhouse gas emissions and thus combating the risks associated with climate change, and by the need to guarantee greater security and diversification in energy supplies, according to Italy's National Energy and Climate Plan. (4)

Energy Supply and Demand

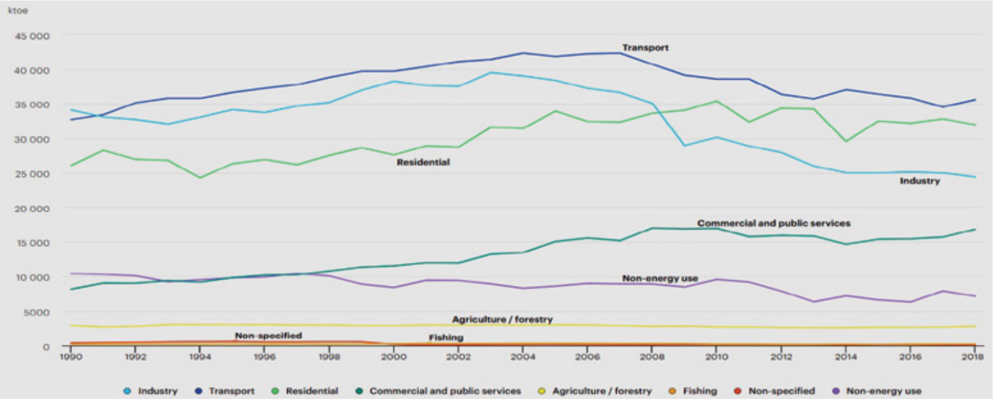
Based on IEA's data, Italy produced 34.7 Mtoe of energy in 2018, recording an increase of 5.6% from 2008 to 2018. The country's total primary energy supply (TPES) was 150.6 Mtoe in 2018, declined by 17.1% over the past ten years, down from 181.7 Mtoe in 2008 (see Figure 6.15). Fossil fuels accounted for 79% of TPES in 2018, broken down in natural gas (39.5%), oil (33.8%) and coal (5.7%). Renewables represented 18.5% of TPES in 2018, up from 36% ten years earlier. Gross inland consumption and final consumption levels fell dramatically in the 2005-2014 period, save for an upturn in 2010, followed by a slight drop in recent years. The fall in the consumption of petroleum products, natural gas and (albeit at an inconsistent rate) coal has been particularly marked. Over the last few decades, renewable energy sources, thanks to a generous scheme of incentives, have played a leading role in a period of significant development in Italy; this period ended in 2013, after which progress has been rather stagnant, with a fall being recorded in 2016. Italy's total final consumption (TFC) amounted to 119.1 Mtoe in 2018, representing around 79% of TPES, with the remainder used in power generation and other energy industries. TFC has declined by 14% from 2008 to 2018. Energy demand is split relatively equally between transport, households and industry. These sectors accounted for 29.9%, 26.8% and 20.5% of total final consumption in 2018 (see Figure 6.16).

Figure 6.15 **TPES by Source in Italy, 1990-2019**



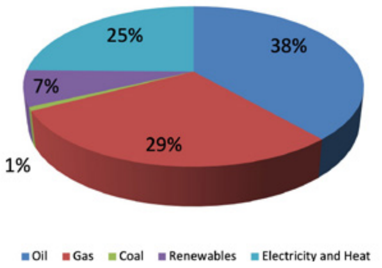
Source: IEA

Figure 6.16 **Total Final Consumption by Sector in Italy, 1990-2018**



Source: IEA

Figure 6.17 **Total Final Consumption by Source in Italy, 2018**



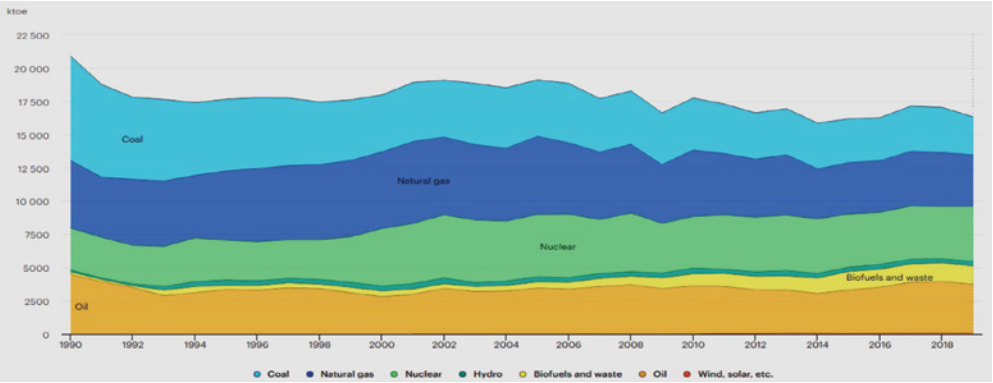
Source: IEA

As far as energy flows are concerned, Italy is a net importer of gas, mainly from Russia, Algeria, Qatar and Libya as well as a net importer of oil and petroleum products, mainly from Azerbaijan, Saudi Arabia, Iraq and Russia. In addition, Italy is a net electricity importer, with imports mainly coming from Switzerland, France, Slovenia, Austria and Greece.

Slovakia

Slovakia's energy system is characterised by a high share of nuclear power, which accounted for 62% of domestic energy production in 2018 and was also one of the largest parts of the total primary energy supply (TPES) (see Figure 6.18). Domestic nuclear energy production helps improve energy security in Slovakia, which otherwise is dependent on large fossil fuel imports, mainly from Russia.

Figure 6.18 **TPES by Source in Slovakia, 1990-2019**



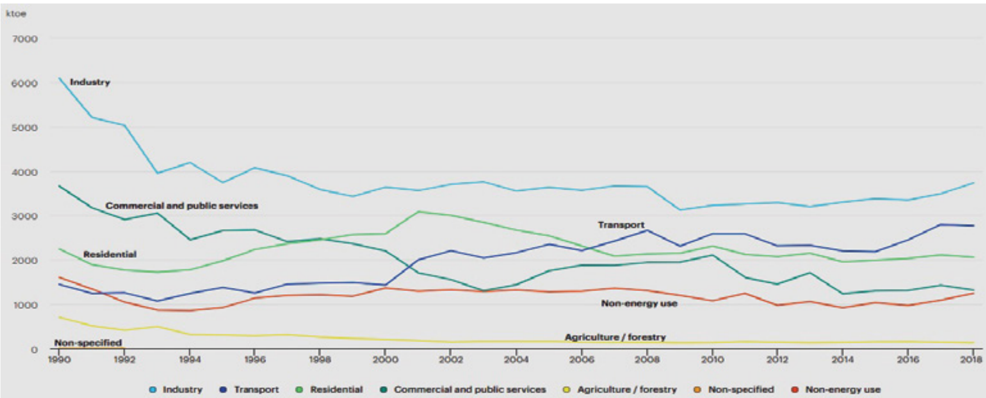
Source: IEA

Natural gas, oil and electricity are the main energy sources, which accounted for 79% of TFC in 2018. Natural gas and electricity are consumed across most sectors, with the largest demand in industry, whereas oil dominates in the transport sector. Slovakia also has an extensive district heating (DH) system, fuelled mainly with natural gas and, increasingly, biofuels, according to the IEA (6).

Energy Supply and Demand

TPES has varied around 15-20 million tonnes of oil equivalent (Mtoe) over nearly half a century. In the past decade, TPES has trended slowly lower, from 18.3 Mtoe in 2008 to 17.4 Mtoe in 2018. Nuclear power production began in the late 1970s and grew rapidly in the mid-1980s and early 2000s as new power plants were introduced. Over the past decade, nuclear energy has decreased slightly as a result of the closedown of two old reactors. Fossil fuel supply has declined more rapidly; from 12.9 Mtoe in 2008 to 11.4 Mtoe in 2018. In contrast, biofuels and waste more than doubled from 0.6 Mtoe in 2008 to 1.4 Mtoe in 2018. Biofuels and waste are mainly used for heat and power generation, or are consumed by industry.

Figure 6.19 **Total Final Consumption by Sector in Slovakia, 1990-2018**

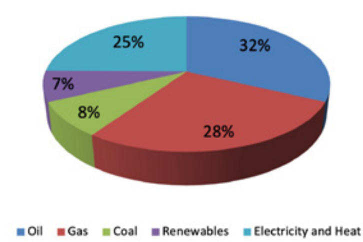


Source: IEA

Energy demand dropped sharply after the collapse of the Soviet Union in the early 1990s. Total final consumption stood at 11.2 Mtoe in 2018. Slovakia has a large industrial sector, notably a fast-growing automotive manufacturing industry, which has replaced some heavy industries from the Soviet era. Industry accounted for over 33% of TFC in the country in 2018, of which 21% was natural gas and oil products used for non-energy purposes in industrial processes. The remaining TFC was in the transport sector (25% of TFC), residential sector (18%) and commercial sector (12%). In 2018, oil was the dominant fuel in transport, whereas natural gas and electricity accounted for the largest share of TFC in other sectors. District heating was the second largest energy source in the residential sector after natural gas in 2018.

As far as energy flows are concerned, Slovakia is 100% relied on Russian gas imports and is a net importer of oil and petroleum products, mainly from Russia, Austria, the Czech Republic and Hungary. In addition, Slovakia is a net electricity importer, with imports mainly coming from the Czech Republic, Poland, Ukraine and Hungary.

Figure 6.20 **Total Final Consumption by Source in Slovakia, 2018**



Source: IEA

Syria

Syria is going through a difficult historical period and faces real challenges in how to meet its electricity demand. Due to the civil war, which this year entered its 10th year, and the control by several parties of its fossil fuel resources and its electricity grid, the country is facing lack of oil and gas production, oil companies shutting down, destruction of the electricity grid, insufficient conversion capacities and financial weakness of energy entities, halting imports, and giving rise to corruption.

Due to the civil war and ensued hostilities in several parts of the country, oil and electricity demand almost collapsed. This is expected to gradually increase as exiled population returns and production activities start again, giving impetus to the Syrian economy. However, the restoration of the national economy and its economic and social development require a sustainable, safe and effective energy sector. According to Jamil and Sidorenko (7),Syria is located within the sunbelt zone; it has about 300 sunny days with high solar radiation. There are many areas where the average annual wind speed exceeds 6 m/s. Highest average wind speeds detected in Sendiania, Barshin and other sites that are suitable for wind power generation.

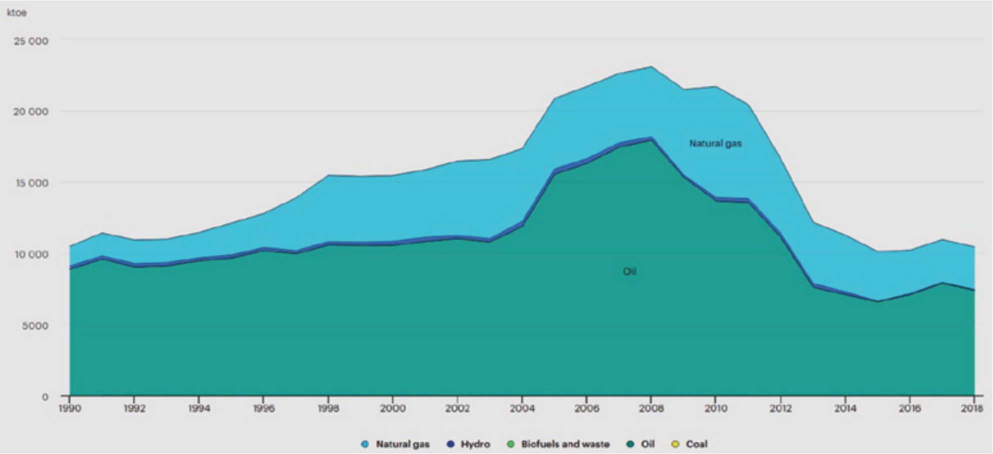
In this respect, Syria has excellent climatological conditions, which could enable the large scale of renewable energy sources' utilization, especially solar thermal, solar PV and wind.

In Syria, the energy supply increased between 1991 and 2008 and then decreased dramatically once the civil war started in March 2011. In 2018, Syria's total primary energy supply reached 10.4 Mtoe (see Figure 6.21), registering a fall of 55% compared to the 2008 pre-war level. In 2001, oil production in Syria stood at 401,000 b/d (or 19.3 Mt), while in 2019 it had collapsed to 24,000 b/d (or 1.0 Mt).

In 2008, Syria became a net importer of natural gas, transported through the Arab pipeline, but the state of conflict in the country and the sanctions affected its ability to receive natural gas. Over the last years, Syria's primary energy supply has been secured through Iranian oil imports since due to sharp fall of its domestic oil production by more than 95% on average from 2011 until today, the country needs to import crude and oil refined products.

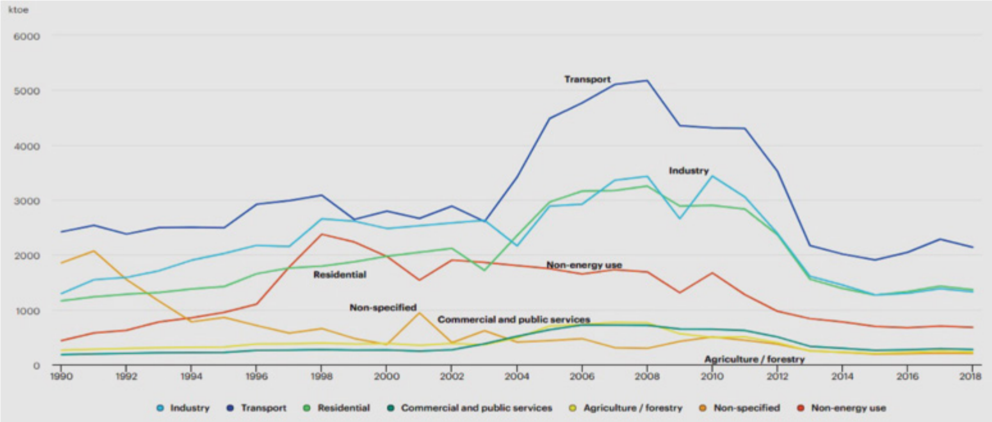
In 2018, Syria's total final consumption (TFC) reached 6.2 Mtoe, recording a fall of 59%, compared to 2008 level. The transport sector had the largest share (34.4%) of the country's TFC in 2018, followed by the residential (21.9%) and industrial sectors (21.3%), as shown in Figure 6.22.

Figure 6.21 **TPES by Source in Syria, 1990-2018**



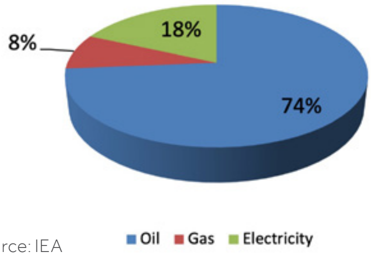
Source: IEA

Figure 6.22 **Total Final Consumption by Sector in Syria, 1990-2018**



Source: IEA

Figure 6.23 **Total Final Consumption by Source in Syria, 2018**



Source: IEA

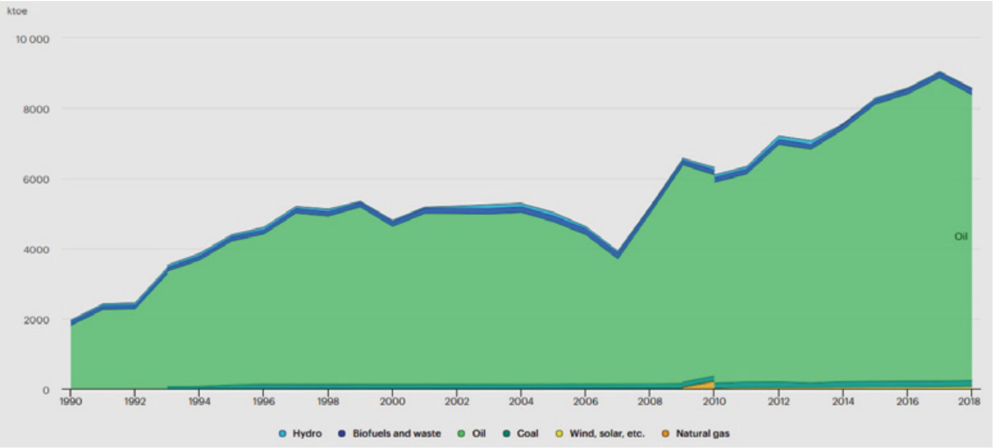
In Chapter 8 on "Hydrocarbon Exploration and Production" of this Outlook, some further discussion on Syria's oil and gas sector is made, especially since the country has excellent geological conditions, which could enable sizeable oil and gas production.

Lebanon

According to IRENA (8), Lebanon relies largely on imports to satisfy its energy demand. In terms of primary energy, consumption is met using the following six major components: (a) liquid petroleum gas (LPG), (b) gasoline, (c) gas oil, (d) kerosene, (e) fuel oil and (f) bitumen. The only energy produced domestically include solar water heating, hydro power and a minor solar PV.

In 2010, energy imports acco unted for approximately 96.8% of primary supply, and only 3.2% was locally produced from hydroelectric power plants and SWHs. The share of primary energy imports did not change significantly between 2010 and 2015, as political instability in the region prevented uninterrupted imports of natural gas, thus forcing various plants to rely on fuel oil. Primary energy production in Lebanon comes from mainly imported oil products. In 2016, fuel imports accounted for around 95% of overall energy production and imports. Some 96% of the country's total primary energy supply (TPES), which stood at 8.6 Mtoe in 2018, was sourced from primary and secondary oils, followed by coal at 2%, based on IEA's data.

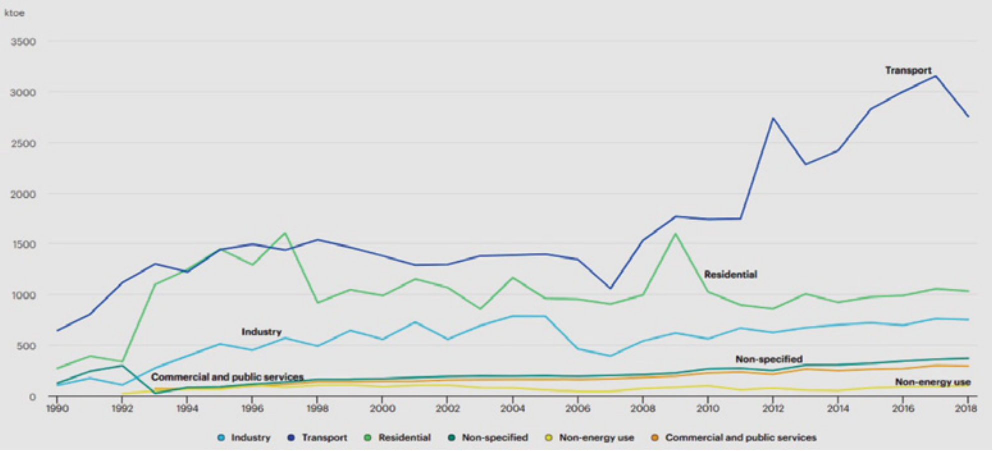
Figure 6.24 **TPES by Source in Lebanon, 1990-2018**



Source: IEA

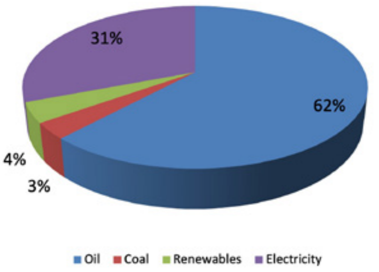
In 2018, the total final consumption (TFC) in Lebanon reached 5.3 Mtoe and was largely met by imported oil and electricity, with the highest share being consumed in the transport sector (52%), followed by the residential sector (19%) and industry (14%). The high dependence on imported oil products has increased the vulnerability of the Lebanese economy to oil price fluctuations. In addition, in recent years, Lebanon has experienced significant intermittency of electricity imports due to regional instability. As well as threatening the country's energy security, this has aggravated the electricity supply shortage. In this context, the country's high dependency on energy imports is a strong driver for the deployment of renewable energy sources, which will help improve Lebanon's energy security.

Figure 6.25 **Total Final Consumption by Sector in Lebanon, 1990-2018**



Source: IEA

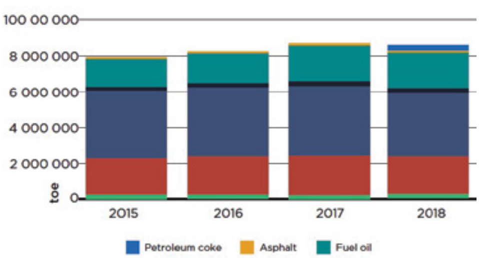
Figure 6.26 **Total Final Consumption by Source in Lebanon, 2018**



Source: IEA

Figure 6.27 shows the evolution of oil products' imports in Lebanon between 2015 and 2018. The evolution of oil imports is consistent with each of the oil products keeping the same share of total imports. In 2019, total imports reached 8,618 ktoe, based on IRENA's data, representing a financial burden of around $6,248 million. Moreover, in 2019, an additional 350 ktoe of petroleum coke was imported, although this is not reflected in Figure 6.27, owing to incomplete information regarding its origin and use.

Figure 6.27 **Oil Imports in Lebanon, 2015-2018**



Source: IRENA, MEW[7]

Egypt

According to African Energy Reports (9), Egypt has significant resource potential in each of oil, gas, wind, solar and hydro. In relation to gas, the 21.5 trillion cubic feet (tcf) Zohr field in the Mediterranean and latest gas agreements with Israel and Cyprus are indicative of ambitious plans to grow into a regional gas and oil hub.

Based on IEA's report (10), gas production in Egypt has undergone dramatic changes since the early 2000s. Domestic output grew by 17% per year on average between 2000 and 2008 (when production reached a peak of 62 bcm) and Egypt became a net exporter of gas. However, a significant reduction in investment resulted in a 40% drop in production between 2008 and 2015. The country became a net importer of gas again in 2015, chartering two FSRUs in order to be able to accommodate in LNG imports. The Egyptian economy is heavily dependent on gas: more than 80% of the country's power generation capacity is gas-fired. Declining domestic output therefore caused repeated power outages and weighed heavily on industrial competitiveness. LNG export facilities were idled, and more polluting oil products started to take market share.

The discovery of the aforementioned large Zohr offshore gas field in 2015, one of the biggest finds worldwide over the last decade, dramatically changed Egypt's energy outlook. With favourable upstream policies to expedite development, production from the Zohr field started in late 2017 and reached around 30 bcm in 2019. This growth is now being supplemented by production from several other fields, notably Nooros, Atoll and the first and second phases of the West Nile Delta complex, leading to a major turnaround in the country's production. Gas production in 2018 returned to the level of the previous peak in 2008 and Egypt achieved self-sufficiency later in the year.

With sustained upstream reforms and efforts to reduce arrears to international operators, gas production in Egypt is expected to grow to around 100 bcm by 2040, according to IEA's Stated Policies Scenario. The upbeat production outlook, coupled with the country's underutilised LNG export infrastructure, opens the possibility of Egypt going well beyond self-sufficiency and becoming a regional export hub, although this would require the resolution of a number of political and commercial issues. However, question marks remain as to Egypt's net export position in the longer term. On the

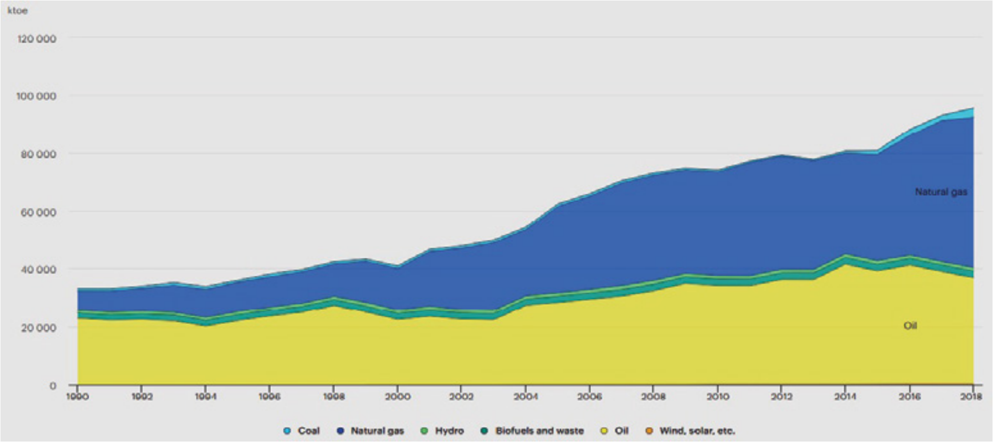
7 Lebanese Ministry of Energy and Water (MEW) (2019), "Update of the electricity reform paper".

supply side, there would be need for continued upstream investment as the outputs from the Zohr and adjacent fields reach a plateau[8]. But the bigger issue is that gas demand in Egypt may rise very rapidly due to demographic reasons and uncontrolled population growth. Egypt is already the largest gas consumer in Africa and there is strong potential for further growth, especially in the power sector where gas is the dominant fuel.

In addition, Egypt is a significant oil producer at around 670,000 barrels per day (b/d) in 2018, equal to 0.7% of global oil production. Much of Egypt's 400 million tonnes of proven reserves are concentrated in oil fields in the North-west (onshore) and the Red Sea (offshore). Currently, Egypt enjoys what is widely regarded as an electricity oversupply. Installed capacity stood at 55.9 GW in 2018, more than enough to meet a peak demand of 30.8 GW.

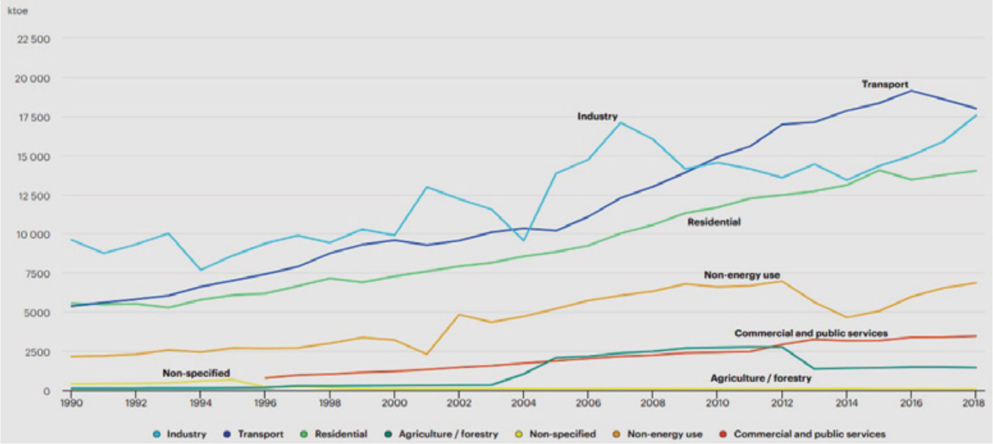
The expansion of renewables' share in Egypt's energy mix is high in the government's energy policy agenda. This is targeted to increase from 10% in 2019 to 42% in 2035. To achieve

Figure 6.28 **TPES by Source in Egypt, 1990-2018**



Source: IEA

Figure 6.29 **Total Final Consumption by Sector in Egypt, 1990-2018**

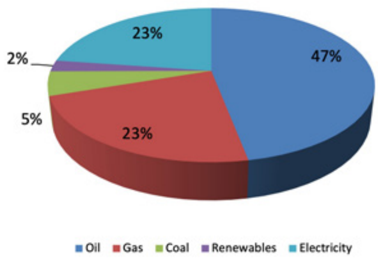


Source: IEA

[8] Trade with other East Mediterranean countries (e.g. imports from Israel, exports to Jordan) can also impact the trade balance.

this, installed capacity would need to reach 93 GW, assuming that no new thermal generation is added, or existing such plants decommissioned. In 2018, Egypt's total primary energy supply (TPES) reached 95.6 Mtoe, with fossil fuels accounting for more than 95% of its primary energy production. As shown in Figure 6.30, oil and gas are, by far, the main primary sources of energy supplied and consumed in Egypt. Renewable energy (i.e. solar, wind, hydro, biofuels and waste) covered about 3.9% of the country's TPES in 2018.

Figure 6.30 **Total Final Consumption by Source in Egypt, 2018**



Source: IEA

In 2018, the total final consumption (TFC) in Egypt reached 61.4 Mtoe, with the highest share being consumed in the transport sector (29.3%), followed by the industry (28.6%) and the residential sector (22.8%).

References

(1) *IEA (2020a), "Azerbaijan energy profile", https://www.iea.org/reports/azerbaijan-energy-profile*

(2) *IEA (2020b), "Austria 2020 – Energy Policy Review", https://www.iea.org/reports/austria-2020*

(3) *IEA (2020c), "Moldova energy profile", https://www.iea.org/reports/moldova-energy-profile*

(4) *IEA (2020d), "Ukraine energy profile", https://www.iea.org/reports/ukraine-energy-profile*

(5) *European Commission (2020), "Italy's Integrated National Energy and Climate Plan", https://ec.europa.eu/energy/sites/ener/files/documents/it_final_necp_main_en.pdf*

(6) *IEA (2016), "Energy Policies of IEA Countries – Italy 2016 Review", https://webstore.iea.org/energy-policies-of-iea-countries-italy-2016-review*

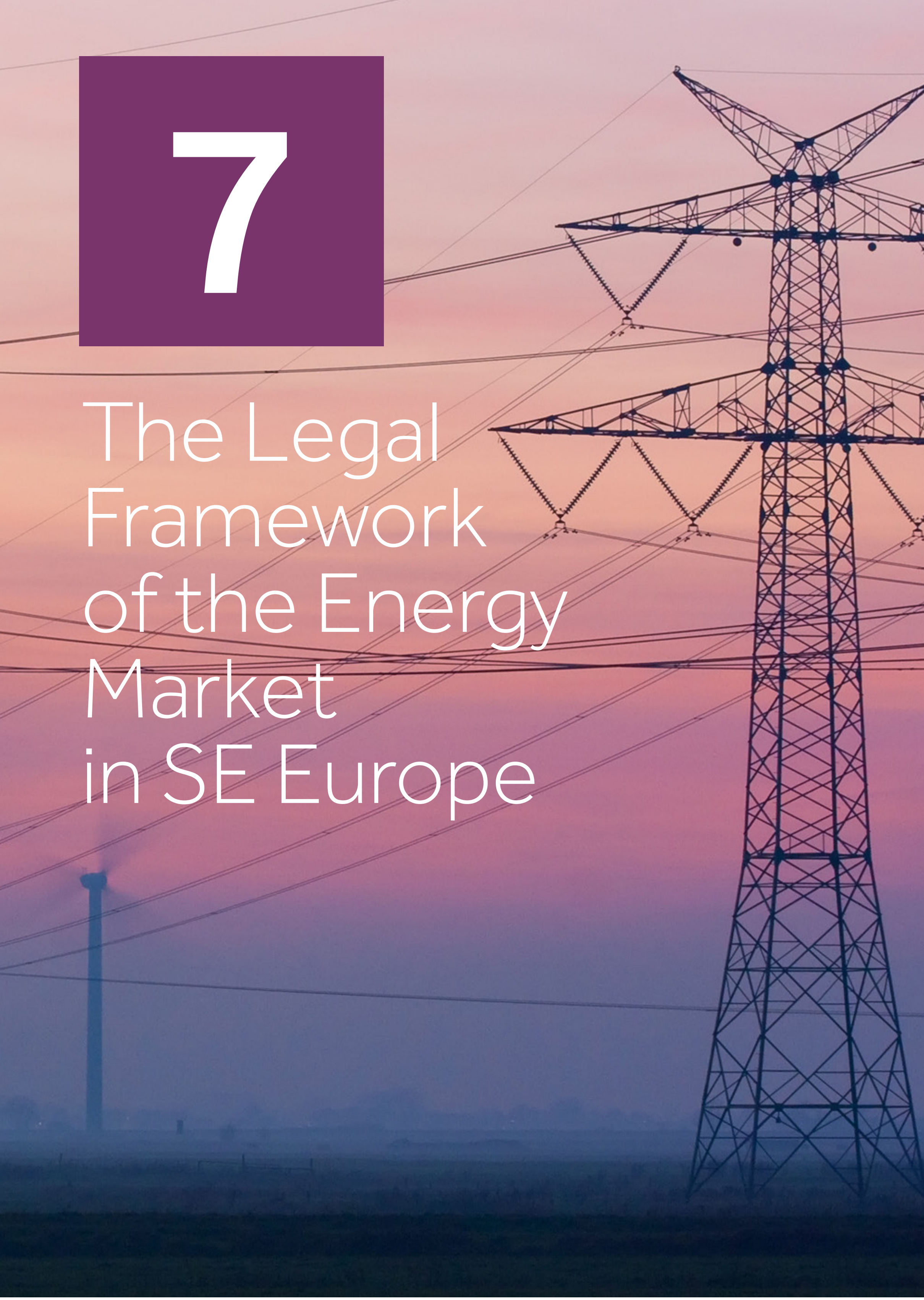
(7) *IEA (2018), "Energy Policies of IEA Countries – Slovakia 2018 Review", https://www.iea.org/reports/energy-policies-of-iea-countries-slovak-republic-2018-review*

(8) *Jamil, A. and Sidorenko, G. (2020), "Energy Visions 2035 for Syria", Journal of Physics: Conference Series, https://iopscience.iop.org/article/10.1088/1742-6596/1614/1/012023/pdf*

(9) *IRENA (2020), "Renewable Energy Outlook: Lebanon", https://www.irena.org/publications/2020/Jun/Renewable-Energy-Outlook-Lebanon*

(10) *African Energy Reports (2020), "Egypt Power Report - 2020"*

(11) *IEA (2020e), "Africa Energy Outlook 2019", https://www.iea.org/reports/africa-energy-outlook-2019*



7

The Legal Framework of the Energy Market in SE Europe

The Legal Framework of the Energy Market in SE Europe

Introduction

Safe and reliable delivery of energy has been the hallmark of energy policy and regulation in the industrialized world over the last century. More recently, regulators, policymakers and the industry began to focus their attention on ways to improve economic efficiency, increase productivity and reduce costs through a seemingly endless series of reforms. In some countries, utilities were encouraged to enhance transmission and interconnection facilities with neighbouring systems in order to pool energy resources. More recently, utilities have been encouraged to participate in regional organisations to buy and sell power, and to administer transmission, dispatch and scheduling of a variety of energy products. Certain countries have encouraged utility efficiency through a variety of performance-based incentives.

Policymakers have tried to reduce the barriers to entry by requiring non-discriminatory treatment among transmission users and prohibiting affiliate abuse. Utilities were encouraged to unbundle certain utility services; in some cases, regulators required the divestiture of generation or transmission facilities. Utilities have even been encouraged to provide retail wheeling services to facilitate competition for delivery service customers.

Consequently, many markets have developed competitive bid-based electricity auctions to set energy and capacity prices, which often take into consideration the cost of transmission congestion. These markets tend to be administered by independent or governmental entities that do not have a market position bias. Clearing prices set in these markets are intended to send price signals to maximise short-term efficiency (scheduling, dispatching and selling energy), as well as long-term efficiency (building new or retiring old generation and transmission facilities).

In certain countries, lawmakers and policymakers have encouraged developers to build and finance new renewable resources and to develop more effective means of conserving energy, through a variety of 'carrots' and 'sticks'. These measures have included subsidies such as feed-in tariffs and renewable energy credits, as well as utility requirements through renewable portfolio standards. In certain competitive markets, conserving electricity has been converted into a demand-side product with near or equal value to supply-side generation. New "smart grid" technologies have been created to increase the efficiency of transmission, generation, distribution and individual consumers' energy use.

Now, however, the myriad of efficiency mechanisms face new and unprecedented challenges. Transmission and distribution systems are ageing and desperately need upgrading. Severe new environmental requirements are leading to mass retirements of baseload coal-generation resources. Fuel prices are volatile, adding long-term uncertainty to energy prices. Spikes in the price of raw materials are making the development of new infrastructure all the more expensive. Cyber-security threats are exposing the vulnerabilities of our energy networks. And the global economy continues to threaten our ability to obtain the necessary credit to build and finance energy infrastructure.

In such a complex and uncertain environment, it is important both for the investor cum market participant, and the consumer to know the rules of the game and how likely these are to change and for what reason. Hence, the need of comprehensive and reliable information on the legal and regulatory framework in force.

Therefore, the aim of this Chapter is to highlight the major aspects of the SE European energy sector from the perspective of legal and regulatory framework over the past few years on a country-by-country basis.

The Chapter is not meant to be a treatise on any particular country's energy legislation and is not exhaustive to the point of eliminating the need of professional advice, but its main purpose is to raise readers' attention as to the energy legislation of each country in SE Europe, as defined by IENE, and assist in identifying the issues that might have a significant impact on investment and business development decisions. Undoubtedly, there are text repetitions as several energy developments touching upon legal and regulatory framework in the SE European region are also covered in other Chapters of the present study (especially in the Country Profiles), while a number of latest regional legal and regulatory energy issues are not included as this Chapter was lately updated in the first half of 2020. A special section has been added at the end of each country's legal framework account to discuss the impact of Covid-19 on investment and support initiatives. As all governments introduced various measures to support businesses affected by government restrictions imposed in response to the Covid-19 pandemic, there have been several side effects impacting each country's finances but also affecting the operation of government and the investment prospects.

7.1 ALBANIA

7.1.1 Introduction to the energy market

In Albania the energy sector is one of the strategic sectors and a priority of the Government of Albanian (GoA) given the diversity of energy resources (water, wind, solar, oil, gas, etc.) that the country possesses, which so far are not fully exploited. Albania has both thermal and hydropower to generate electricity, with the latter being more significant and having a greater potential for development. Liberalization of the energy market continues to be among the reform priorities of the GoA, along with the diversification of the energy sources and reducing energy dependence from imports. In the energy sector, the progress made to reduce distribution losses and by improving bill collection rate, despite the promising results, needs further consolidation. The reform for diversifying energy sources is crucial for having sustainable and growth-promoting public finances.

7.1.2 Electricity

Market overview

The introduction of the new Power Sector Law[1], a Third Energy Package Compliant Law was proclaimed as a major step forward, providing the legal ground for the establishment of a liberalised energy market. However, for the third year in a row, the country focus remained on the implementation of the Third Energy Package and its major tasks such as unbundling and certification of transmission system operators, unbundling of distribution system operators and full market opening. This required further concrete reforms with respect to market rules, e.g. related to balancing, day-ahead markets, market coupling, etc.

In 2016 the Government of Albania approved the new Albanian Market Model ("**AMM**") developed in accordance with the EU Directives on Electricity and also adopting the requirements of the Energy Community Treaty. The AMM outlines the main responsibilities and relationships among the market participants and Energy Regulatory Entity ("**ERE**"). In simple terms, the AMM is characterised by bilateral contracts for electricity between and among market participants. Ancillary services for Transmission System are purchased by the Transmission System Operator ("**TSO**").

Also in 2017 the ERE approved the Albanian Energy Market Rules ("**Market Rules**") which define:

(a) a set of rules that establish the procedures for market operations and management;
(b) a coherent framework under which participants in the electricity market can interact with each other;
(c) sale and purchase of electricity at freely negotiated prices; and
(d) conditions for participating as part of the Balancing Electricity Market.

[1] Law No. 43/2015, dated 30.4.2015 "On power sector", as amended.

These Market Rules promote an effective generation and supply of electricity and also the competition in sale and purchase of electricity.

To complete legal unbundling, which has starts since 2008, the state-owned power distributor OSHEE established three independent subsidiaries for distribution system operation, provision of universal service and supply of consumers on the market. Their assets, however, remain with OSHEE, which challenges their independence and leaves the formally unbundled service providers without operational capacity.

Balance responsibility is implemented by "transitional" balancing rules and the National Power Corporation KESH is still the sole service provider. In the absence of a local market price, the imbalances are settled using reference hourly prices from the Hungarian day-ahead market. Liquidity of the balancing market could be provided by services across the border, however, cross-border balancing between TSO and neighbouring transmission system operators is not in place yet. The amendments to the Power Sector Law of March 2018 have put in place the missing legal framework for the future organized day-ahead and intraday markets and set the timing of the Government's decision on establishment of the Albanian power exchange APEX to be taken by September 2018. The day-ahead and intraday market rules were developed and approved by ERE but their application is postponed until the corresponding functions are set. The momentum needs to be regained in order to accomplish the establishment of the independent market operator in 2019.

Regulatory overview

The Power Sector Law and the AMM define the participants in the energy market which include several operators and the ERE. Although presently, the contracts and tariffs between the various market participants are regulated at their inception in the energy market, under the new Power Sector Law the applicable tariffs shall be determined by free negotiations between parties to the contract. Thus, no other recent regulated electricity market activities have been observed.

The regulated market is presently organised and regulated through the following contracts between:

(a) KESH Gen and Wholesale Public Supplier ("**WPS**") (primarily for transparency of sale prices charged);
(b) WPS and Retail Public Supplier ("**RPS**");
(c) Transmission System Operator ("**TSO**") and other market participants for transmission-related services, including ancillary services;
(d) Distribution System Operator ("**DSO**") and other market participants for distribution-related services;
(e) Small Power Producers ("**SPPs**") and the WPS;
(f) RPS and its tariff customers;
(g) KESH Gen and Traders, including import contracts for the exchanges of power, which are subject to ERE scrutiny or procurement rules;
(h) OST and KESH Gen, SPPs, Independent Power Producers ("**IPPs"**) and Traders for the transmission losses and Ancillary Services.

The ERE retains the right to adopt standard agreements or procurement rules that are obligatory to be executed by Eligible Suppliers ("ESs"), IPPs, SPPs and other market participants when carrying out a bilateral contract with the WPS. Pursuant to the provisions of the AMM, some contracts between market participants are not regulated; thus, they are freely negotiable between the parties and these include:

(a) contracts between ESs and Eligible Customers ("**EC**");
(b) contracts between SPPs, IPPs, ECs and Traders;
(c) contracts between KESH Gen (i.e. the generating arm of the WPS and ESs or Traders, to the extent permitted under the present or other restrictions on WPS sales; and
(d) contracts between DSO and Traders, ESs, SPPs and IPPs for the necessary energy required to cover losses in the distribution system.

Trading and supply of electricity

The present AMM is a vertically integrated market model characterised by bilateral contracts for electricity between and among market participants. The AMM has directed that Wholesale and Retail Supply be public activities. Thus, after the unbundling of KESH, three different entities now fulfil the activity of the wholesale production, supply and retail supply of electricity.

KESH Gen retains the licence for the generation of electricity and is entitled to sell electricity produced to the WPS at prices approved by the ERE. In all cases, the ERE is entitled to monitor the process of the exchange and sale of electricity, in order to ensure compliance with the rules and procedures of sale and exchange of electricity, as approved by the ERE.

The WPS, being a separate entity in possession of a licence for the wholesale supply of electricity is entitled to purchase from KESH Gen all the electricity produced by KESH Gen from its hydropower plant and other generation plants, as well as from IPPs, SPPs, ESs and Traders to fulfil its obligations to the Retail Public Supplier ("**RPS**"), i.e. to service all the Tariff Customers.

The AMM also comprises: the RPS - an entity licensed for the retail supply to tariff customers at regulated prices determined by the ERE; IPPs - entities producing electricity that are not connected with the grid; Grid System Operators which maintain, operate and upgrade the grid in high, medium and low voltage levels and SPPs which are entities licensed to produce electricity by hydro, wind or other sources which qualify for feed-in tariff if their installed capacity fulfils the legal requirements (for hydro sources - up to 15 MW); and lastly, Traders and Tariff Costumers conclude the list of participants of the AMM. Pursuant to the provisions of the AMM some contracts amongst market participants are not regulated and so are freely negotiable.

Under the AMM, Traders are licensed entities which buy and sell electricity with the exception of sales to the RPS and end-user customers. Traders should be established as legal entities and the scope of their activity should be the wholesale buying and selling of electricity. Traders can buy electricity from KESH Gen (i.e. surpluses), IPPs and SPPs to then sell on to QSs, WPS, or a DSO (covering the distribution losses). When IPPs or SPPs sell directly to the WPS or other ESs, they require only a production licence and not a trading licence.

IPPs, SPPs and ESs may also be Traders, engaged in wholesale transactions, on the condition they obtain the necessary trading licence. The ERE shall ensure that the licences and licensing procedures for ESs and Traders are transparent and non-discriminatory and do not create an undue burden on the entry of Traders into the Albanian market, subject to any reciprocity agreement.

The Market Rules recently were amended by the ERE to reflect the obligation of all market participants to balance the electricity system under the Power Sector Law as of 1 January 2016.

Transmission and grid access

Transmission is regulated by the Transmission System Code - a document describing the relations between TSO and users and establishes procedures for the operation and development of the Transmission System according to the development of the Albanian and Regional Electricity Market.

The Power Sector law provides the unbundling of the transmission system operator and the distribution system operator as well as certain provisions regarding the certification process by ERE.

7.1.3 Renewable energy

Market overview

Albania is almost entirely depending on hydro power as hydropower resources now account for almost 98% of the country's energy production. Hydropower production fluctuates and is not equal throughout the year and, especially during 2017, has resulted in high energy imports, both in quantity and in prices due to dryness periods. This disbalance underestimated the great potential that Albania has in developing other sources of renewables, such as solar or wind sources of energy.

In February 2017, the Parliament approved the new law on promotion of the use of energy from renewable sources (the "**2017 RES Law**")[2], which is partially aligned with the EU RES Directive No. 2009/28/EC, as part of the *Acquis* – an obligation Albania has as a potential candidate for accession to Europe. The adoption of the 2017 RES Law has promoted and encouraged other sources of energy to start with pre-sale electricity contracts for generating works that are not subject to concession, thus proving for a diversified renewable energy resource policy. This is also due to the advancement on electricity production from renewable sources by technologies other than the one dominating domestic electricity production actually, with hydro resources only, as well as the rapid reduction of electricity generation costs from solar energy (PV) and wind (Aeolian), are globally the main sources of energy capacity increase in the wholesale market.

The Power Sector Law provides renewable energy producers with priority and guaranteed access to the electricity networks and also priority dispatch of electricity produced from renewable sources. All market participants including renewable energy producers are required to take balance responsibility.

Albania has taken a number of steps to include in its energy policy the requirements of the EU Directives for the establishment and development of the internal energy market and the promotion of production and consumption of energy from renewable energy sources.

Under the existing legal framework, the ERE is tasked with approving the necessary procedures and documentation for the connection of generation facilities to the grids. The alignment of the existing procedures for connecting renewable producers to the transmission and distribution networks as well as methodologies for establishing the cost of connection, in order to comply with the requirements of the Power Sector Law have not been yet completed. The ERE has adopted simplified procedures for the licensing of renewable energy producers which are connected to the distribution grids.

At present renewable energy makes up around 40 per cent of Albania's energy supply. This is largely due to the fact that virtually all electricity production is generated from hydropower. Many concessions and licences have been granted over the years to private companies for the construction and operation of small hydro-power plants although only a small percentage have been constructed to date (many still requiring financing). Diversification of energy sources through the promotion of production and consumption of energy from renewable sources remains one of the major reforms in this sector.

Other renewable sources are being explored, several licences have been issued for the construction and operation of wind farms. Given the beneficial conditions of the Mediterranean climate, solar power and photovoltaic energy generation are viable options, in addition to biomass and waste to energy sources for which some licences have been granted to date.

[2] Law No. 7/2017 of 2 February 2017 "On promotion of the use of energy from renewable sources", The Law 2017 RES Law is partially aligned with the Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

Based on the Article 5 of the Law No 7/2017 of 2.02.2017 "On promotion of the use of energy from renewable sources", the National Renewable Energy Action Plan 2018 – 2020 ("**NREAP**") was approved, which sets out the roadmap for achieving the national target for the share of energy produced from renewable sources, consumed in the Electricity Sector, transport and in the heating and cooling sector by 2020. Specifically, the NREAP foresees an increase of the consumed electricity generated from renewable sources, with at least 172 ktoe (2,044 GWh) by 2020. NREAP also foresees the expansion of installed electricity generators based on renewable sources to 798 MW. The NREAP takes into consideration the progress in the development of these technologies towards these targets and adjusts them accordingly to ensure the achievement of the national target of RES consumption (38%) in 2020.

Support schemes

The existing Power Sector Law and the wider legal framework provide for certain types of support mechanisms that are granted to investors exploiting renewable energy sources. These are summarised below:

(a) Custom Duties Exemptions: a specific law has been approved to promote the construction of installations using renewable energy sources and which grants exemptions from custom duties for the import of machinery and other equipment to be used in the construction of installations using renewable sources.

(b) Feed-in Tariffs: this is the most successful form of support scheme and although in the renewable energy law feed-in tariffs are to be applied to many renewable energy sources, currently the option is only available for new and existing small hydropower plants ("**SHPP**") (i.e. with installed capacity up to 15 MW). The feed-in tariff is set by the ERE annually and any SHPP producer can upon request benefit from a 15-year power purchase contract with the WPS using the feed-in tariff for the entire term; the new Power Sector does not provide any longer for this form of support scheme.

(c) Guarantee of Origin Certificates ("**GOC**"): GOC's are official certificates issued as evidence that the power generated is from renewable sources. This certificate is issued after the qualification of the plant as being a generator from renewable sources and must be acquired prior to receiving a Green Certificate. The certificate shall include the amount of power generated by renewable sources, the name of the power plant and its capacity. GOCs can be transferred together with the power in accordance with rules and procedures defined by ERE.

(d) Green Certificate ("**GC**"): GC's are official certificates proving that the power was generated through renewable sources or by a combined generating mode which can be transferred (i.e. traded), separately from the power it certifies. The GC certifies the owner and also the place of generation, date of generation and the generating plant. GCs can be transferred in accordance with the rules and procedures defined by ERE.

To date there is only one international agreement for the sale and purchase of GCs and GOCs: the Agreement between the Italian Ministry of Productive Activities, the Italian Ministry of Environment and Protection of Territory and the Albanian Ministry of Infrastructure and Energy. With this agreement, Albanian and Italian power generators are able to sell their respective GCs and sell power with GOC to buyers from the other country. The 2017 RES Law establishes a broad framework for the auction mechanism and Contract for Difference (CfD) in future renewable projects. Currently, the state support in support schemes of RES in energy market in Albania is intended to be restructured for renewable energy sources and aims to replace the existing scheme of the feed-in tariff with a system based on CfD.

[3] By operation of the Council of Ministers Decision No. 179 of 28 March 2018 "On the approval of the National Renewable Energy Action Plan (NREAP) 2018 – 2020".

The new Albanian market model (approved pursuant to law 43/2015 "On energy sector" as amended), provides for the trading of energy from renewable sources, to the advanced/ liberalized market aimed to be opened by means of establishment of the Albanian Power Exchange (intended to start from January 2019).

Auction process

The Albanian government has recently passed a resolution in July ("CMD 349/2018 on RES Support Schemes"), designating the means for promoting the use of energy generated from solar and wind power plants and which stipulates the procedures for electing the eligible projects to benefit from such means.

According to the 2017 RES Law, feed-in-premium tariffs for renewables with over 2 MW of installed capacity should be granted through a competitive auction process, on non-discriminatory, clear and transparent basis. Notably, the CfD will not apply to small RES facilities (i.e. projects with an installed capacity up to 2MW and 3MW in solar and wind energy respectively), as these projects are supported by separate measures.Specific rules on how the auction process will be organised are broadly introduced in the CMD 349/2018 on RES Supportive Measures. It therefore remains to be seen whether the supportive scheme will help to create a suitable investment environment for RES projects in Albania.

Contract for Difference (CfD)

Under the 2017 RES Law, the main promotional measure is a specific form of a feed-in tariff termed contract for difference. The CfD can be characterised as a sliding feed-in-premium system, meaning that renewable energy producers will sell the electricity in the market and receive the variable difference between the auction price and the electricity market price (reference price) as a support measure.

The CfD will have a duration of 15 years. Interestingly, if prices in the electricity market go up and are higher than the auction price, the RES producers will be obliged to pay such difference.

The legal criteria of RES generation established by the Albanian Energy Regulatory Entity (ERE) provides that only the generators that fulfils the legal conditions might be supported pursuant to a CfD. The renewable technologies that will be acceptable for support according to CfD scheme include the following: (i) biomass transformation, (ii) wind in terrestrial boundaries, (iii) solar photovoltaics, (iv) hydro energy, (v) energy from the waste through CHP, (vi) gas from landfills and (vii) gas from the waste urban water.

Other supporting measures

The CMD 349/2018 on RES Supportive Measures provides for further support measures, including:

- making available to the RES producer the immovable properties required for the project implementation;
- priority access to the transmission and distribution grids; and
- producers receiving a guarantee of origin for their produced electricity.

However, the RES producers will not receive support in the form of an assumption of imbalances responsibility, as they will be responsible for their own imbalances and will be required to conclude either a contract with the transmission system operator or to transfer the balancing responsibility to another responsible balancing party, thus becoming a member of a balancing group.

Applicability of supporting schemes in practice

The applicable target for RES share in gross final consumption of energy in Albania for year 2020 is 38 %. Given the great potential Albania has for the construction and operation of new solar or wind power plants, the new support scheme under the 2017 RES Law can be a valuable tool.

In practice, none of the schemes has been implemented, thus causing further delays in implementing the new legislation, mainly for the following reasons:

- Necessary secondary legislation for net metering schemes, access to and connection with grid as well as guaranties of

origins are not in place as yet (this and other documentation is to be drafted as part of an ongoing project financed by EBRD);
- No CfD model has been drafted;
- Market openness and establishment of Power Exchange is postponed to January 2019.

Finally, the actual implementation of the 2017 RES Law will highly depend on the real willingness of the Albanian government to promote RES.

Based on the Law No 7/2017 dated 02.02.2017 "On promotion of the use of energy from renewable sources", was approved by the Council of Ministers Decision No. 369 of 26.04.2017 "On the approval of the methodology to decide the purchase price for electricity generated by small renewable sources from sun and wind". The Decision of Council of Ministers provides the tool to calculate the true cost of solar and wind implementation in Albania. As stipulated by this CMD, ERE is obliged to approve the purchase price of electricity produced from small renewable sources of sun and wind, in accordance with this methodology and averaged costs. Based on this CMD, the ERE Board by means of the Decision No 120 of 27.07.2017 decided that the electricity purchase price to be paid to small renewable sources from sun and wind" for 2017 is 100 Euro/MWh for photovoltaic and 76 Euro/MWh for wind; Actually, ERE with the Decision of the Board of Commissioners No 19 of 19.01.2018 "On the annual purchase price to be paid to existing priority producers of electricity for the year 2018", has approved the initiation of procedures for the approval of new price for year 2018, to be paid to priority producers;

Based on the Law No 7/2017 dated 02.02.2017 "On promotion of the use of energy from renewable sources", was approved the Council of Ministers Decision No 349 of 12.06.2018 "On the approval of support measures for the promotion of the use of electricity from renewable sources of sun and wind, as well as procedures for selecting projects for their benefit". This Decision establishes support measures for the promotion of the use of electricity from renewable sources of sun and wind and procedures for selecting projects that benefit from these measures, according to Article 8(1) of Law No 7/2017 of 2.02.2017 "On promotion of the use of energy from renewable sources" and the objectives of the National Renewable Action Plan 2018 – 2020. Supportive measures to promote the use of electricity from renewable sources of sun and wind are provided through a competitive, open, transparent and non-discriminatory process that provides credibility to participants and guarantees the provision of these measures to Albania's Economic Reform Programme 2019-2021, 80 entities that provide the best conditions for as regards the price of energy, technology used and the way of building the plant.

Based on the Council of Ministers Decision No 349 of 12.06.2018 and the objectives of the National Renewable Action Plan 2018 – 2020, the Ministry of Infrastructure and Energy (MIE) opened the bidding procedure to select the developer of the project for the construction of a photovoltaic plant with an installed capacity of 50 MW, as part of the Support Measures, in the Akërni Area (close to Vlora) and the construction of additional capacity of 20 MW up to 50 MW, which will not be part of the Support Measures.

Activities planned 2019:

- Implementation of the National Action Plan for Renewable Energy Sources (2018-2020), and achieving the national target for the share of energy produced from renewable sources,

- The signature of the contract and the beginning of the implementation of the Project for the construction of a photovoltaic plant with an installed capacity of 50 MW, as part of the Support Measures, and the construction of additional capacity of 50 MW, which will not be part of the Support Measures, in the Akërni Area (close to Vlora).

- The preparation and the approval of secondary legislation based on the Law No 7/2017 of 2.02.2017 "On promotion of the use of energy from renewable sources"

7.1.4 Natural gas

Market overview

Albania does not have a developed gas market at present and such development is one of the priorities set out in the National Strategy of Energy. Albania has a very low level of gas consumption, particularly with over 90 per cent of its energy being produced from hydro-power. However, it is in a prime location to serve as a transit country and is not yet connected to the international gas networks though this shall change in the future. It is thus important for the country to expedite the process of implementation of the Gas Master Plan and thus the gasification of the country.

Regulatory overview

Law No. 102/2015, dated 23 September 2015 "On the gas market" ("**Gas Law**") transposing the Third Energy Package was adopted in October 2015. It sets out a deadline of 18 months for the adoption of secondary legislation. This deadline was introduced taking into account the current absence of gas infrastructure and a gas market in Albania. The development of secondary legislation with the support of the Energy Community Secretariat commenced in December 2015. The Gas Law defines two main roles:

(a) The Ministry responsible for the energy sector, i.e. MEI is the supreme institution responsible for: (i) developing policies and plans for sustainable development; (ii) guaranteeing the sustainable and safe development of new natural gas infrastructure; (iii) approving and updating the National Energy Strategy which is further adopted by the Council of Ministers; (iv) preventing and managing crisis situations; (v) approving technical and safety rules; (vi) collecting and processing all information and data on the national energy balance, including the gas market;

(b) The ERE is responsible for regulations of natural gas activities and also for monitoring the security of gas supply (except for natural gas exploration and production, which is regulated under Law No. 7746, dated 28 July 1993 "On hydrocarbons (exploration and production), as amended" ("**Hydrocarbon Law**").

With the enactment of the new Gas Law, the ERE has expanded its scope of regulation to cover gas and has begun the preparation of the regulatory framework for the Natural Gas Sector. To date it has amended its Rules of Practice and Procedures and with the assistance of international advisors and donors it has completed the Licensing Procedures for the Natural Gas Sector and is working towards completing the set of rules and regulations to ensure proper functioning of the sector. However, the new Gas Law has substantially improved to ensure full and proper transposition of the Third Energy Package and is to a large extent aligned with the gas acquis.

Regulated natural gas market activities

As noted above the natural gas market is largely regulated and supervised by the ERE. Under the Gas Law the following activities require a licence: (a) transmission; (b) distribution; (c) supply (retail sale); (d) trading (wholesale); (e) operation of natural gas storage facilities; (f) operation of LNG facilities. Each activity requires its own separate licence and the licensing procedures are regulated by the sub-legal acts approved by ERE[4].

The Gas Law requires all natural gas undertakings to have obtained a license from the ERE before commencing activities in the gas sector, except for the operation of direct pipelines. The detailed procedure is specified in the relevant licensing rules adopted by decision of the regulatory authority – ERE and nothing has changed since their adoption.

[4] Decision No. 9, dated 11 February 2011 of the Board of Commissioners of ERE "On natural gas sector rules and procedures on licensing, modification, partial/full transfer, revocation and renewal of licences".

Exploration and production

The exploration and production of natural gas are both activities separately regulated under the Hydrocarbon Law (see below under Section 5).

Transmission and access to the system

As provided for under the Gas Law, the criteria for ensuring that users receive equal treatment and freedom of access to the gas transmission/distribution network are defined by the ERE. The activity of natural gas transmission and distribution is of public interest and is performed respectively by the TSO and DSO.

Trading and supply

As provided for by the Gas Law, the ERE is authorised to regulate the procedures and principles for tariff-setting.

LNG and storage capacity

The diversification of energy sources, through the development of the gas sector, consists of: creating a complete legal and institutional framework for the sector; the undertaking of a number of regulatory initiatives and investment projects in the gas infrastructure and market, whose main objective is to ensure significant security of energy supply through integration of the Albanian natural gas network on the regional and European ones, and increased economic benefits for the population and the different sectors of the economy in the country.

7.1.5 Upstream and the oil market

Market overview

All natural resources in Albania (inland and offshore) are owned by the state which has the right to explore, develop, extract, exploit and utilise natural resources. Pursuant to the Law No. 7746, dated 28 July 1993 "On hydrocarbons" (exploration and production), as amended (the "Hydrocarbons Law"), the state acting through MIE is entitled to grant a petroleum agreement to a person [one type of which is a Production Sharing Agreement ("**PSA**")] the right to explore, develop and exploit hydrocarbons in a defined area as agreed in the relevant PSA. The Natural Agency for Natural Resources ("**AKBN**") was created back in 2006 to deal, *inter alia*, with hydrocarbon activities on behalf of the Albanian state. The AKBN is a specialised institution dealing with the negotiations of the PSA, the monitoring of petroleum activities and policy-making processes.

The governmental objective is to negotiate the terms of the PSA with the oil industry in a fair and balanced manner, by taking into consideration the typical risks associated with exploration and the state's legal entitlement to revenue as the owner of the natural resources. There are predetermined means to grant a free block for exploration, development and production activities, so it can be either granted by the initiative of the MIE launching a tender process or the MIE inviting other interested parties to express their interest to this particular block in case a request or the same block has been lodged with the ministry. The blocks/oilfields/reserves designated for exploration, development and production are set out by the MIE itself.

Albania stands among 51 countries adhering to the Extractive Industry Transparency Initiative ("**EITI**"), a global initiative which seeks to improve the governance of the extractive sector. As of April 2015, different public entities from local and central government levels as well as current contractors which have entered into PSAs, are obliged to report to the EITI, pursuant to the standards set forth from this later and secondary applicable legislation.

Regulatory overview

Petroleum operations are regulated under the Hydrocarbons Law which together with a few accompanying regulatory acts and the Decree No. 782, dated 22 February 1994 "On the fiscal system in the petroleum sector", as amended ("**Law on petroleum taxation**"), forms the legal framework for the exploration, development and exploitation of petroleum in Albania.

Any person wishing to carry out petroleum operations must firstly obtain either a Prospecting Permit or enter into a PSA with terms and conditions which will be negotiated with the AKBN. In the latter case there is no separate licence per se; all matters are regulated and encompassed in the relevant PSA.

Taxation on petroleum, regulated by Law on petroleum taxation is levied as flat tax on taxable profit. Under this law, taxable profit is equal to accumulated revenue less accumulated capital and operating expenses as specified in the terms of the Petroleum Agreement. Accordingly, profit tax is applied when cumulative revenue exceeds capital and operating expenses accumulated since the start of operations.

Foreign investors becoming part of a petroleum agreement may negotiate fiscal stability terms to prevent future changes in certain taxes, however such stability should be limited to a certain period of time, applicable upon the entry into force of the relevant PSA and should not be extended during the entire term of the said PSA.

The current PSAs applicable in Albania are based on a cost recovery contract model and the GoA share is determined from the split of profit oil pursuant to the relevant percentages specified in each PSA. The contractor is entitled to recover all costs and expenses under the abovementioned PSA model, out of the share of available petroleum (i.e. the cost oil, which is sometimes called "cost recovery petroleum, cost recovery crude oil or cost recovery gas", as applicable). Whereas the stock of petroleum outstanding after the recovery of the contract costs, which is considered as "profit oil", should be allocated between the contractor and the GoA in accordance with a scale/formula specified in each PSA. The Hydrocarbon Law does not set out a specific manner of calculating the share or parameters since such is subject to negotiations between the parties of the PSA. At the beginning of 2016, the MIE publicly announced changes in the cost recovery model aiming to obtain from the oil companies the profit tax since the start of the production phase. According to this new model, 90% of revenue will be allocated for cost recovery purpose, while 10% of revenue will be classified as net profit and taxed in accordance with petroleum profit tax law and regulation. The new cost recovery model described above and limitation in fiscal stability clauses were incorporated in the most recent PSAs granted since 2017.

In February 2017 the Albanian parliament approved the Law No. 8/2017, dated 2 February 2017 "On the status of workers in the petroleum and gas industry", which sets minimum financial and healthcare benefits for the workers in the petroleum and gas industry. Both current and former petroleum workers will benefit from this status. They will be entitled to a salary not less than 150% of the minimum salary in force, higher pension payments and will further benefit from paid leave, which is double the time of paid leave labour regulatory framework in Albania. In case of illness directly or indirectly caused by their work conditions, the GoA will cover the treatment costs through a special health fund. The workers are further entitled to a payment in case their employment is terminated due to sector / company restructurings. Petroleum agreements awarded after the enforcement of this new law shall request oil companies to establish and manage a professional pension fund with contributes amounting to no less than 10% of their employees' gross salaries.

Regulated oil market activities

With the exception of activities conducted pursuant to a prospecting permit, no person can engage in petroleum operations without being authorised by MIE in accordance with the agreed terms and conditions stipulated in a Petroleum Agreement/PSA. A prospecting permit authorises the holder to carry out inter alia, perform prospecting activities in the areas covered by the permit by means of aerial, geophysical, geochemical, paleontological, geological, topographical and seismic surveys and to study their interpretation; and file an application for a PSA, if petroleum is discovered.

The Hydrocarbon Law states that the permit shall be valid for a two-year term, shall be not exclusive, shall not authorise the drilling of exploration wells and shall not grant to the permit holder any priority right (over any other party/person) to enter into a Petroleum Agreement/PSA with MEI, except when expressly stated so in the Prospecting Permit.

The PSA is a contract entered into between the AKBN acting on behalf of the MIE and the contractor allowing for the exclusive rights for the contractor to undertake explorations within the contract area for a period of five years (subject to extension as noted below) and exclusive rights to exploit for a period of no more than 25 years. Other typical provisions in a PSA relate to:

(a) Contractor property rights and right to construct and operate required infrastructure subject to third party rights and access under the law;
(b) Contractor right to trade and export petroleum exploited under the terms of the PSA;
(c) Fiscal regime applicable to operations (and exemptions applicable under the law);
(d) Obligation to perform a minimum work program backed by a performance guarantee;
(e) Obligation to present an annual work program and budget;
(f) Preference given to local employment and supplies during petroleum operations, where these are competitive in terms of quality, availability and cost;
(g) Change of law indemnities measures;
Obligation of the Contractor to carry out the Petroleum operations in a safe and proper manner in accordance with the generally accepted international petroleum industry practice and by causing minimal damage as is reasonably practicable to the general environment including, *inter alia*, the surface air, seas, lakes, rivers, marine life, animal life, plant life, crops, other natural resources and property, and shall forthwith repair any damage caused to the extent reparable, and shall pay reasonable compensation for all damage which is beyond repair.

Under the PSA the Contractor is authorised to conduct petroleum operations during an initial exploration period which can be extended twice. It is preferred that the exploration period includes a drilling commitment by the contractor. The phases of the Exploration Period are subject to negotiation. In the event that the Contractor declares a commercial discovery during the exploration period, it has the right then to proceed and extend for a development/production period of 25 years, which can also be extended. During the exploration period, the Contractor is subject to minimum work programs and expenditure obligations.

Exploration expenditures and capital expenditures are recoverable only in the case of a commercial discovery but not before the start-up of production. Operating expenditures are recoverable during the year in which they are incurred. Reasonable and necessary administrative expenditures of the Contractor are also recoverable. The Contractor is subject to tax on profit at a rate of 50 per cent of the realised profit and the royalty at typically 10 per cent of sales revenues.

One of the main priorities of the government is to reform the oil sector by restructuring and privatising the national state-owned company Albpetrol. The changes will confirm that the petroleum agreement ("**Albpetrol Agreement**") entered into on 26 July 1993 between Albpetrol and the Ministry at the time responsible for the energy sector, will be in force after Albpetrol's privatisation process. In addition, all rights over the management of free oil and gas blocks (blocks yet not operated by contractors), previously granted to Albpetrol, have been transferred from Albpetrol to MIE. The Ministry will have the sole discretion to negotiate with possible investors the petroleum agreement related to any free block and Albpetrol, once privatized, will only be responsible for blocks in which Albpetrol is currently conducting petroleum activities autonomously. After Albpetrol's privatisation, MIE and Albpetrol will enter into a new Petroleum Agreement, to determine the terms and conditions of Albpetrol's activities and to confirm the blocks in which Albpetrol will continue its activities.

Material provisions of the hydrocarbon's legislation and other licensing regulations

As of February 2017, the procedures for entering into a hydrocarbon agreement for the exploration, development and production of hydrocarbons are made through either the notice of the relevant MIE inviting the interested parties to participate through applications (so through the launch of a tender process); or invitation of other entities for submitting their applications, invited by the MIE, once they have already received a request for exploring/ developing a block /blocks or specified resource/s. Further, the MIE reasons of national security may refuse to enter into a new PSA or may refuse the approval of the assignment of shares of an existing hydrocarbon agreement.
The Petroleum law offers some incentives to foreign contractors, amongst which, the right to export their share of production derived from operations in Albania, unless there is an emergency call on the supply of crude oil in the local market.

As a matter of law, the conclusion of a PSA is exclusively based on the provisions of the Hydrocarbons Law and two 'umbrella' agreements (in case of reserves administered by Albpetrol). The first is Albpetrol Agreement, a special petroleum agreement concluded on 26 July 1993 between the Albanian state oil company (Albpetrol) and the MIE, acting on behalf of the Albanian state which is the sole owner of oil deposits. Under the Albpetrol Agreement, Albpetrol is entitled to carry out petroleum operations in certain oilfields and to do so also in cooperation with private companies under individual petroleum agreements (PSCs etc.). This is so, provided that Albpetrol has previously concluded for the specific oilfield, a so-called license agreement with MIE, duly represented by AKBN. Basically, by means of the license agreement, the Ministry (AKBN) entitles Albpetrol to conduct petroleum operations in the contract area and enter into PSAs with private contractors. The PSA between Albpetrol and the specific contractor makes them both part of the Licensee under a license agreement and jointly and severally liable to the Ministry (AKBN) pursuant to the license agreement. Albpetrol has no longer any pre-emption right over the free blocks. So, in case of an early termination of a PSA entered between MIE, Albpetrol and a contractor, Albpetrol will not have the exclusive right to continue any petroleum activity until the expiry date of the said PSA. The MIE will have the right to assign the free blocks to potential new contractors, according to the regulation on new petroleum agreements' approval procedure. As regards blocks administered directly by AKBN, only a single agreement, mostly in the form of a PSA is directly entered with the AKBN.

7.1.6 Forthcoming developments in the Albanian energy sector

The desired full and complete liberalisation of the energy sector is not quite accomplished yet and there are still fundamental reforms required and legal framework to be reinforced. The first step was made with the adoption of the new Power Sector Law which sets as a priority the development of a competitive energy market; the encouragement of a regional and European electricity trade and the improvement of investment conditions in the electricity sector. The subsidiary legislation is yet to be amended and aligned with the new Power Sector Law.

As part of the package of legislation in the energy sector, a new law on Energy Efficiency has been enacted, which has partially transposed the Directive 2012/27/EU and other amendments of this Law are currently under drafting process aiming the full transposition of the Energy Efficiency Directive.

The Gas Sector Law shall also be amended by fully bringing it in line with the Third Package of European Union Directives on the energy sector. In respect of the oil and gas sector, regulatory and policy developments are also underway as part of the overall state energy strategy. A new regulation and a draft law on the activity of exploration and production of hydrocarbons in Albania are expected to be approved by the GoA.

7.1.7 Impact of the coronavirus pandemic on energy and infrastructure[5]

A. Covid-19 Response Investment and Support Initiative – General

The Albanian Government and other public authorities have introduced various measures to support businesses affected by the government restrictions imposed in response to the Covid-19 pandemic in Albania. Below is a list of the key measures introduced until 10 April 2020:

(1) Financial subsidy to salaries of certain categories of employees and taxpayers (Council of Ministers' Decision no. 254, dated 27 March 2020);

(2) Sovereign guarantee to second-tier banks for loans covering salaries of employees of certain companies the activity of which has been shut down or impaired due to Covid-19 outbreak (Council of Ministers' Decision no. 277, dated 6 April 2020);

(3) Loan instalments deferral for borrowers suffering financial difficulties during the Covid-19 pandemic (Joint Order of the Prime Minister and the Governor of the Bank of Albania of 17 March 2020);

(4) Income tax filings and payment postponements for 2020 (Council of Ministers' Normative Act no. 10, dated 26 March 2020);

(5) Postponement of prepayment of simple profit tax instalments (Council of Ministers' Normative Act no. 11, dated 27 March 2020);

(6) Postponement of filing applications related to energy and gas licensing (Energy Regulatory Entity's Decision no. 51, dated 26 March 2020).

Except for the measures taken by the Energy Regulatory Entity (energy and gas sector), the initiatives have not been introduced on the basis of sectors, rather on the basis of business categories (self-employed, SMEs, larger businesses) adversely affected by governmental decisions.

The initiatives offer a variety of support including financial support, credit support, postponement of filings or tax prepayment deadlines, etc.

The financial subsidy to the salaries of certain categories of employees and taxpayers applies to:

(a) Employees of legal persons or sole entrepreneurs registered for CIT or as small businesses with an annual turnover not exceeding ALL 14 million during 2019. Employees shall be paid the minimum salary of ALL 26,000 per month. Double employed individuals may benefit only one payment.

(b) Self-employed individuals with an annual turnover not exceeding ALL 14 million and their family members working against no payment for them are entitled to benefit the minimum salary of ALL 26,000 per each person.

The sovereign guarantee to second-tier banks for loans related to salaries of employees of certain merchants and companies applies to companies larger than those covered by the first initiative, though the qualifying criteria remain to some extent unclear. The loan instalments deferral applies to borrowers having encountered financial difficulties during the situation caused by the Covid-19 pandemic and as such being unable to serve their loans. However, no further eligibility criteria have been set out and the credit institutions are granted discretion for assessing applications.

Income tax filings and payment postponements apply to certain businesses subject to income tax. Specifically, a four-month postponement is made available for

[5] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook/

the filing of financial statements and related documentation of all categories of businesses namely by 31 July 2020, instead of 31 March 2020. For taxpayers with a yearly turnover of up to ALL 14 million, the payment date of the income tax calculated on the basis of the yearly statement is postponed to the second half of 2020. For the same category of taxpayers, the payment of income tax instalments for the first and second quarter of 2020 is postponed until 31 December 2020. Payment deadlines for taxpayers with a yearly turnover exceeding ALL 14 million together with a deadline for the submission of yearly personal income statements remain unchanged. Postponement of prepayment of simple profit tax instalments applies to businesses subject to simple profit tax. Postponement of filing applications related to energy and gas licensing (new licence, renewal, compliance, etc.) applies to companies operating in the energy and gas sectors.

Access

(1) With respect to the financial subsidy to the salaries of certain categories of employees and taxpayers, application should be made in the Albanian governmental electronic portal www.e-albania.al.

(2) With respect to the sovereign guarantee to second-tier banks for salary loans, application should be made following a cover agreement to be concluded between the Albanian Government and the various second-tier banks identified in the same Decision.

(3) With respect to the loan instalments deferral, beneficiaries should address a reasoned request to their credit institutions in order to benefit the right of postponement of the term.

(4) With respect to income tax filings, application should be made through the tax authority website.

(5) With respect to postponement of prepayment of simple profit tax instalments, application should be made through the tax authority website.

(6) With respect to postponement of filing applications related to energy and gas licensing, application should be made through the Energy Regulatory Entity.

Ease/speed of access

(1) With respect to the financial subsidy to the salaries of certain categories of employees and taxpayers, upon application, the tax authorities will verify the data within the first 10 days of the following month.

(2) With respect to the sovereign guarantee to second-tier banks for salary loans, credit institutions should process the requests of beneficiaries within three days upon receipt of the request.

(3) No details are provided in relation to the loan instalments deferral.

Period of support

(1) The financial subsidy to the salaries of certain categories of employees and taxpayers shall be effective as of 1 April 2020 and last no longer than three months.

(2) The sovereign guarantee to second-tier banks for salary loans shall be available to companies for a period of no longer than 30 days from the conclusion of a cover agreement between the Albanian Government and the various second-tier banks identified in the same Decision.

(3) Loan instalments deferral shall be made until 31 May 2020.

(4) Filing of financial statements and related documentation on all categories of businesses is postponed by four months i.e. by 31 July 2020 instead of 31 March 2020. For taxpayers with a yearly turnover of up to ALL 14 million, payment date of income tax calculated on the basis of a yearly statement is postponed to the second half of 2020. For the same category of taxpayers, the payment of income tax instalments for the first and second quarter of 2020 is postponed until 31 December 2020.

(5) Postponement of prepayment of simple profit tax is offered until October 2020 for prepayments due in the first and second quarter of 2020 and until December 2020

for the prepayments due in the third and fourth quarter of 2020.

(6) Filing applications for energy and gas licenses are postponed by one month after the end of the pandemic.

The initiatives taken have not addressed the interaction with existing insurance covers. Some useful links include: www.qbz.gov.al (Official Gazette Website, Albanian only) https://shendetesia.gov.al/masat-e-reja-per-te-parandaluar-perhapjen-e-covid-19/ (Ministry of Health and Social Protection Website, Albanian only)

B. Impact on the Energy and Infrastructure Sectors

The energy sector is not covered by the Order of Minister of Health and Social Protection no. 193, dated 20 March 2020 which specifies the sectors/industries whose activities are shut down for the duration of the Covid-19 pandemic. Thus, legally the sector is not affected by any prohibition of activity order. However, the movement restrictions imposed by the Government (including the prohibition of public transportation, time limitations of free movement of people, etc.) have impaired the normal functioning of such businesses.
For the supportive measures, see above.
Furthermore, the Ministry of Infrastructure and Energy has postponed bidding deadlines for certain projects.

The infrastructure sector is not covered by the relevant Order of Minister of Health and Social Protection no. 193, dated 20 March 2020. Yet, the Public Procurement Agency has notified all public authorities asking to suspend for a specified term (initially two weeks) all contracts except for those that "are indispensable". This notification, while legally questionable, has also created confusion among the respective companies. Moreover, the movement restrictions imposed by the Government (including the prohibition of public transportation, time limitations of free movement of people, etc.) have impaired the normal functioning of such businesses.
Furthermore, the Ministry of Infrastructure and Energy has postponed bidding deadlines for certain projects.

As a general note, the measures taken by the Albanian Government relating to the limitation of free movement and the support of individuals/businesses have raised legal questions about their lawfulness (particularly constitutionality). Most importantly, the Government declared the State of Natural Disaster only on 24 March 2020 (Council of Ministers' Decision no. 243), which could have been a plausible legal basis justifying all restrictive measures taken by the Government earlier, i.e. as of 11 March 2020.

Apart from this, such measures, including the supporting ones, remain to a considerable extent unclear (especially in relation to eligibility criteria, etc.), therefore leaving room to public authorities for considerable discretion in implementing them. This, in turn, seems to have already affected negatively businesses.

7.2 BULGARIA

7.2.1 Introduction to the energy market

The Bulgarian energy sector has undergone serious transformation in the last decades and continues to attract foreign investments in Bulgaria. Bulgaria is one of the few countries in the region with nuclear power facilities and due to its geo-economic location, it is a focal point for a number of strategic energy infrastructure projects.

The sector is mostly privatised, and the market is fully liberalised (particularly in the electricity sector). The Bulgarian state still holds substantial energy assets by way of a holding company named "Bulgarian Energy Holding" ("**BEH**"). BEH controls some large electricity generation capacities (including the largest lignite coal power plant and the only large pumped-storage hydroelectric power plant), the electricity transmission system, and the natural gas transmission, storage and supply.
In June 2011 the Bulgarian Parliament adopted the Energy Strategy of the country until 2020,

which acknowledges the challenges and sets out five priorities for the sector aiming to ensure energy needs and protect consumer interests: guaranteeing the security of supplies; boosting energy from renewable sources; improvement of energy efficiency; development of a competitive energy market.

7.2.2 Electricity

Market overview

After the implementation of the so called Third Energy Package[6], the liberalization of the market has been a major trend and source of controversies in the last years. Practically all customers other than household and small business or public consumers connected to low voltage networks were forced out of the regulated market. On the generation side, in the context of the commitments of BEH approved by the European Commission under the case opened against BEH for alleged abuse of dominant market position in the wholesale electricity market in Bulgaria, the generation subsidiaries of BEH were compelled to offer part of their electricity at the newly opened local electricity exchange ("**IBEX**"). By way of reforming the scheme for promotion of electricity generation from renewable sources most of local renewable generation facilities were also compelled to sell their electricity at the electricity exchange. The development of the open market and the electricity exchange as its backbone have not gone as smoothly as planned with major local industrial consumers complaining of lack of transparency and predictability at the market and alleged market manipulation involving state-owned generation companies as a result of which major price spikes were recorded at the IBEX in the second half of 2018 and continuing in 2019. The insolvency of certain major electricity traders also caused turbulences in the market. The only sector which has remained 100 per cent owned by the State is the national transmission grid and the supplies of electricity for the regulated market through the transmission grid. Currently, the national transmission network is owned by ESO after the unbundling of transmission assets from the assets of the National Electricity Company EAD ("**NEC**") which now remains responsible for national supplies in the regulated market and owns a number of generation capacities. Both companies are owned by the Bulgarian Energy Holding EAD which is also the owner of some project pipeline, mining and heat production companies and the nuclear power station Kozloduy. ESO deals with the operational regime planning and control of the electrical power system in Bulgaria, the synchronisation of the Bulgarian electrical power system operation with the electrical power systems of the European countries member of the Union for the Coordination of Transmission of Electricity ("**UCTE**") and coordination of joint operation with other electrical power systems.

The distribution and end-supply networks were privatised and are beyond the control of the State, albeit under a licence regime only. The production of electricity is currently performed by both state and privately owned companies with the Bulgarian state still controlling the vast majority of the (most cost effective) generation through the Kozloduy NPP, the largest lignite power plant Maritsa East 2 and the largest hydro power plants owned by the National Electricity Company EAD ("NEC"). The indicative goals for the energy mix up to 2020 correspond with the EU goals for broadening the share of renewable energy and reduction of CO_2 emissions.

The regulatory framework has been constantly changing in recent years. A set of amendments to the Energy Act were introduced in 2012/2013 aiming further liberalization of the energy market. These implement in detail Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 and the Third Energy Package principles in general in the following manner:

[6] The package consists of two Directives, one concerning common rules for the internal market in gas (2009/73/EC), one concerning common rules for the internal market in electricity 2009/72/EC) and three Regulations, one on conditions for access to the natural gas transmission networks ((EC) No 715/2009), one on conditions for access to the network for cross-border exchange of electricity ((EC) No 714/2009) and one on the establishment of the Agency for the Cooperation of Energy Regulators ACER ((EC) No 713/2009). They were adopted in July 2009.

- division of transmission from production and sale of electricity and introduction of guarantees for independence of the grid operators;
- guarantees for the development of the grid;
- introduction of new powers to the Energy and Water Regulatory Commission;
- clear definition of consumer rights;
- exclusion of the users of high and middle voltage electricity from the regulated market and the introduction of the last instance suppliers;
- setting up of the Independent Bulgarian Energy Exchange which started operations in January 2016.

Significant changes to the Energy Act and the Energy from Renewable Sources Act were also introduced in 2018 and again in May 2019 by way of which the framework for promotion of the generation of electricity from renewable sources and highly efficient co-generation was materially amended and such generation facilities (with exception of those with installed capacity of less than 1 MW) were compelled to sell their electricity at the IBEX.

Regulatory overview

The regulation of the electricity sector has several layers.

The first layer is the core energy regulatory framework covering, among other things, the regulation of electricity generation activities, encouragement of production of electricity from renewable sources, relations between the investor and the distribution/ transmission companies, etc. These issues are regulated mainly by the Energy Act of 2003 (State Gazette No. 107 of 9 December 2003, as amended from time to time). Special rules applicable to renewable energy projects are set out under the Energy from Renewable Sources Act of 2011 ("**RES Act**") (State Gazette No. 35 of 3 May 2011), the Energy Efficiency Act of 2015 (State Gazette No. 35 of 15 May 2015). There are also a number of secondary level regulations issued by the Council of Ministers or competent Ministers (such as the Minister of Energy) regulating various aspects such as price regulation, security and safety requirements for electricity equipment, connection to the grid, etc. The local energy regulator – the Energy and Water Regulatory Commission also issues secondary level regulations such as Rules on Trading in Electricity, Rules for Access to Electricity Networks, etc.

The government bodies and institutions which are granted powers to monitor and regulate the electricity sector include:

(a) The Parliament – according to the Energy Act the Parliament of Bulgaria approves a Strategy for Sustainable Energy Development of Bulgaria;

(b) The Council of Ministers of Bulgaria – the Council drafts and implements the above Energy Strategy approved by the Parliament;

(c) The Minister of Energy (the "**Minister**");

(d) The Energy and Water Regulatory Commission (the "**Commission**" or the "**Regulator**") – this is the main regulatory body for the energy sector (as well as the water and sewage sector). Apart from its general powers, the Commission has been also granted investigatory and enforcement powers to control the enforcement of the prohibitions under Articles 3 and 5 and the obligations under Article 4 of Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency;

(e) The Sustainable Energy Development Agency – this is a state authority responsible for the implementation of the State policy on encouragement of the production and consumption of electricity and heating power produced from renewables.;

(f) Electricity System Operator EAD – this is a company indirectly owned by the State.

Regulated electricity market activities

The Energy Act provides for licensing regimes in the electricity sector.Special rules were introduced in 2018 in respect of activities of operators of publicly accessible electricity charging points but those remain not subject to a licensing regime.

Subject to price regulation by the Regulator are the prices for the following activities:

(a) Connection, transmission through and access to the national transmission grid and the regional distribution networks;
(b) Sale of electricity by generation companies to the public supplier NEC within certain quotas which are determined by the Regulator for the purposes of meeting the demand of the regulated market;
(c) Generation from renewable energy sources (subsidies) in certain cases;
(d) Sale of electricity by the public supplier NEC to the end suppliers for sales at the regulated market which comprises business and household customers connected to the low voltage grid;
(e) Sale of electricity by end suppliers to their clients at the regulated market – households or business consumers which are connected to the low voltage grid;
(f) The prices for other services determined by the Regulator related to the core licensing activities of a licensee.

The prices for electricity at the balancing market as well as the prices for the electricity supplied by the last resort suppliers are not determined by the Regulator (thus not subject to regulation in the strict sense) but are determined by the licensee for the respective activity under rules and methodology approved by the Regulator.

Material licences for electricity generation

Regarding the Licensing Regulation (State Gazette No. 33 of April 2013) and the licensing procedures there are no recent remarkable changes in the Bulgarian market.

Under the Energy Act, any company which owns or intends to construct electricity generation facilities with an installed capacity of over 5 MW must obtain a generation licence from the Commission. The requirements for the persons applying for a licence are set forth in the Energy Act and the Ordinance for licensing of the activities in the energy field, State Gazette No. 33 of 5 April 2013 ("Licensing Regulation").

The licence may be issued with a term of validity between one and 35 years taking into account the service life of the generation assets and the financial status of the applicant. The term of the licence may be extended for a period not longer than the initial term, provided that the licensee meets the requirements of the Energy Act and duly performs all its obligations and complies with the requirements under the licence.

Generally, the preconditions for issuance of a licence under the Energy Act are the following:

(a) The applicant should be a legal entity registered in compliance with the Bulgarian Commerce Act or the legislation of any EU or EEA Member State. Such entity should not be insolvent or in liquidation;
(b) The applicant should have the technical and financial capabilities, material and human resources and organisational structure necessary for performance of the licensed activity;
(c) The energy facilities for carrying out the licensed activity should comply with environmental protection and safety operation requirements; and
(d) The applicant should have property rights over the energy facilities (if they are constructed). An application for a licence may also be filed before the facility is constructed.

The documents and information which need to be submitted with the application to evidence the applicant's compliance with the abovementioned requirements include: (i) business plan for up to 5 years; (ii) application for approval of prices (if the licensed activity involves regulated prices); (iii) information on the financing sources for the activity; (v) information on the applicant's or its controlling shareholders' experience in carrying out an activity similar to the licensed one; (vi) information on the applicant's management and organisational structure and the education and qualifications of the management personnel.

A licence preceding the construction of the energy production facility can be issued upon request of the applicant, provided that it can prove the necessary financial means to construct the facility. In this case the licence shall provide for the terms and conditions for construction of the facilities (i.e. wind turbines and the infrastructure thereof) and commencement of the licensed activity.

Upon completion of the facilities' construction, the licensee should request that the Commission issue a special permit for the facilities to enter into commercial operation. The above licences and permits are without prejudice to any other ancillary requirements which may be prescribed by the general legislation, such as building permits, health and safety approvals, environmental impact assessments, etc.

Trading and supply of electricity

(a) Trading
The market in electricity was liberalised in theory since 2007 but the practical liberalisation occurred at much slower pace and the free market consisted of only about 100 (mostly high voltage grid) consumers as of 2012.

The amendments introduced in the Energy Act in 2012, 2013 and 2015 for implementation of the Third Energy Liberalization Package directives and recently in 2018 and 2019 forced the market liberalization and the practical operation of the balancing market and the electricity exchange. As a result as of the end of 2017 there were more than 130,000 consumers active in the free market[7]. Raising wholesale prices at the IBEX during 2018 and major price spikes on numerous occasions however seem to undermine the confidence in the market of both customers and traders. Media reports note that numerous traders have exited the market in 2018 and according to the annual report of the local Regulator about 25,000 customers have left the open market and moved back to supplies at regulated prices (an option that is yet available for small business consumers connected to the low voltage grid).

In January 2016 the long expected exchange for electricity trading in Bulgaria started to operate. IBEX was originally incorporated as a state-owned company (a subsidiary of BEH) but in order to assure the independence of IBEX from the state-owned energy stakeholders in February 2018 the shares of IBEX were acquired by the Bulgarian Stock Exchange AD – the company that operates the only functioning regulated stock exchange market in Bulgaria.

In order to boost the IBEX market, new rules have been recently introduced pursuant to which all generation facilities with an installed capacity of 1 MW or more must sell their electricity at one of the market platforms of IBEX. Only generation companies which supply their own facilities or third parties customers via direct electricity lines as well as renewable energy generation facilities put into operation after 1 July 2019 are exempted from the above requirement and may sell electricity via bilateral agreements.

IBEX opened with a day-ahead market and added a centralized market for bilateral contracts at the end of 2016 and an intraday market in April 2018. According to information from IBEX as of June 2019 there were 71 active members operating on the day-ahead market, 64 – on the centralized market for bilateral contracts and 53 on the intraday market of the exchange. On the first two platforms, deals are concluded automatically and at clearing prices determined by the exchange systems and IBEX is itself a counterparty on all deals and carries the corresponding risks and responsibilities. On the third segment, bilateral deals are actually concluded, and the role of IBEX is as an intermediary between the trading participants, but IBEX is not a party to the deals. Deals may be concluded by way of automatic or manual counteroffers matching or by way of organizing of sale or purchase auctions by trading participants. The Commission in accordance with its powers has approved Rules for Trading

[7] Data provided by the Association of traders with electricity in Bulgaria.

in Electricity (State Gazette No. 66 of 26 July 2013, as amended and supplemented).

According to the Rules, the ESO administrates deals with electricity as well as organises the balancing of the market (the covering of the differences between scheduled deliveries and actual physical deliveries). For the purpose of the balancing of the market, hourly schedules have to be provided to ESO by the free market solo participants and the coordinators of balancing groups and they arrange the imbalances by selling to or purchasing electricity from ESO covering the positive or negative imbalances. Each year the Commission issues decision for determining quotas (quantities) of electricity to be produced by certain producers and sold to NEC as a public supplier at prices determined by the Commission (for the purposes of the supplies at the regulated market).

In May 2019 the access and transmission fees as well as the 5 % levy in favor of the ESF over exported electricity were finally abolished as a consequence of a judgment of the ECJ in Luxembourg of December 2018 prohibiting Member States from imposing a levy on the export of electricity produced on their territory. Bulgaria was the only country in the European Union that imposed such levies on the electricity produced on its territory which were viewed as de facto export fees in breach of EU laws and were a substantial hindrance to the plans for market coupling of the Bulgarian electricity exchange market with those of neighboring countries.

(b) Supply
In accordance with Directive 2009/72/EU the model of independent transmission operator was introduced and ESO has been licensed as such. In addition to the national high voltage network owned and operated by ESO, there are four distribution network operators in Bulgaria (owners and operators of mid and low voltage regional grids - **DSO**s) and four end-supply companies (form the same corporate groups as the DSOs) - licensed entities which supply electricity at regulated prices to household consumers and companies connected to the low voltage grid who have not chosen a supplier at the free market.

Only household customers and (small) non-household customers connected at the low voltage network can be supplied in the regulated market. Theoretically such customers may choose to be supplied at the open market as well but due to the more favourable and predictable conditions for supply at the regulated market, only a marginal number of them have so chosen. All other customers must choose a supplier at the open market.

The end suppliers in each distribution network as well as NEK act also as suppliers of last resort (**SLR**s) with the obligation to supply electricity to customers who are to be supplied at the open market but have not chosen an electricity trader or when the chosen electricity trader fails to supply for reasons non-attributable to the customer. The SLRs' final selling prices are determined by the SLRs in accordance with a methodology approved by the energy regulator. Any client has the right to choose a supplier (whether a local one or located in another EU country). The relevant grid operator performs the change of supplier pursuant to the Rules within three weeks as of receiving of a request in writing from the client.

All consumers connected to the high and middle voltage grid are outside the regulated market and have to choose their supplier in the free market. In order to secure electricity supply for those who have not made their choice of supplier / the supplier they have chosen is still not technically capable of supplying electricity in the respective region – the figure of the last resort supplier has been introduced wherein the Commission determines the prices of the electricity to be sold by the last resort supplier.

Transmission and grid access

Connection
The connection to the grid is regulated by the Energy Act and a special Ordinance No. 6 of 24 February 2014 (the "**Connection Ordinance**").

Connection to the grid shall be performed by either the ESO (the owner of the national transmission grid) or the respective company owner of the regional distribution network (depending on whether the generation capacity is below or above 5 MW).

According to the applicable rules, the procedure consists of three stages:

• Official statement on the terms and conditions for connection
Upon request by the respective applicant of connection the network owner must issue a statement on the terms and conditions under which it shall connect the generation facility to the network. The statement describes the technical requirements for the facilities of the project and the facilities which have to be constructed in order for the connection to be made. Connection may be refused only on objective technical reasons and the refusal is subject to appeal before the Commission.

• Preliminary connection agreement
As a next step the applicant must sign a preliminary agreement for connection to the network based on the terms described in the statement for connection.

• Final connection agreement
After the issuance of a Construction Permit for the respective facility applying for connection a final Connection Agreement is signed.

The connection fees payable to the gird owner are regulated by the Commission.
(a) Transmission and access to the grid agreement
Connection Agreement invites the company to sign it within 15 days of filing the Application. The term of the final connection agreement cannot exceed two years as of its execution and it is terminated upon commissioning of the project.
(b) Access to the Grid Agreement
Upon commissioning of the project an access to the grid agreement shall be concluded as a condition for the grid user to enter into power purchase agreement and be supplied with energy. The access to the grid agreement must be subject to general terms and conditions approved by the Commission. Consumer supplied at regulated prices are not obliged to sing access agreements but are supplied through the grid under general terms and conditions approved by the Commission. The agreement shall deal with the indemnification payable by the owner of the network to the company in the event of limitations of the evacuated electricity.

Fees are payable by grid users for the access to and transmission of electricity supplied to them through the grid are regulated by the Commission. Until 2019 only local customers and PV and wind generation companies were obliged to pay access fees but as of July 2019 such fees were also introduced for all local generation companies.

7.2.3 Renewable energy

Market overview

The sector for generation of electricity from renewable energy sources has gone through significant turbulences and has been subject to numerous changes of the applicable legal regime in the last ten years.

Originally in 2007 Bulgaria adopted a scheme for promotion of electricity generation from renewable sources (RES) based on feed-in-tariffs (mandatory off-take of all generated electricity at special preferential prices). In 2011 a new law was adopted – the Energy from Renewable Sources Act (the "RES Act") preserving the same concept but introducing certain specific requirements. The declared purpose of the law was to deal with the issues created by the previous legal framework and namely the booming development of new projects which in many cases were built in environmentally sensitive areas.

However, due to the late adoption of the new rules and the inadequate regulatory decisions taken, the new rules have not helped "cool down" the developments in the sector and more than 900 MW of RES generation capacity was connected to the grid in 2012 alone (mainly photovoltaic) at preferential prices high above local market process. This created significant pressure on consumer electricity prices and urged the government and the energy regulator to practically halt any future developments and to seek various means to restrict the operation of renewable capacities already connected.

Ultimately, by amendments to the Renewables Act as of 2015, all support schemes for new projects commissioned after January 2016 were suspended, except for the projects with an overall capacity of up to 30 kW constructed over roofs or facades of buildings connected to the distribution grid or the land adjacent to such buildings in urbanized territories.

The efforts to optimise the promotional regime continued in 2018 by restructuring completely the promotional regime for all existing RES projects as well (see below for details).

Support schemes

The RES Act provides for a system of encouragement of generation of electricity from renewables based on feed-in tariffs. The system comprises the following key elements:

(a) The owners of the national transmission grid and/or regional transmission systems are obliged to connect renewable energy generation facilities, subject to compliance with the special procedures under the Renewables Act. The interconnection costs associated with interconnection facilities up to the boundary of the electrical facilities are borne by the generation company. General costs associated with the expansion of the capacity of the grid are borne by the grid owner;
(b) The owners of the national transmission grid and/or regional transmission systems are obliged to provide guaranteed access to the grid and transmission as well as priority dispatching of electricity generated from renewable sources subject to relevant technical requirements for the security of the system;
(c) The national supplier (NEC) and the regional suppliers (end-suppliers) are obliged to purchase all electricity generated from renewable sources, which is certified with a generation (origin) certificate (see below). This obligation is to be reflected in long-term power purchase agreements signed with the respective purchaser; and
(d) Special preferential prices are set by the Commission at which electricity from renewable sources is purchased (see below).

Feed-in Tariff System

A system of promotion of generation of electricity from RES involving conceptually a feed-in-tariff (FiT) system and long-term power purchase agreements (PPAs) has been in place in Bulgaria since 2007 and until recently, even though the details of such system have been changed numerous times.

Originally the system envisaged an entitlement of RES producers to sell all electricity generated to a dedicated off-taker. The off-taker was the national supplier NEK (for facilities connected to the transmission grid)[8] or the relevant licensed regional end supplier (for facilities connected to the relevant distribution grid) . That entitlement was guaranteed under a long term power PPA with the relevant off-taker for periods depending on the category of RES used for generation (12 years for wind and 20 years for PV). The tariffs at which RES producers were entitled under the PPAs was determined by the Commission annually and the prices were different depending on the type of RES and the capacity of the generation facilities. The price applicable to a particular facility was the one determined by the Commission for the period when the respective facility was put into operation. Such price was then applied for the whole period of the relevant PPA.

The legal framework envisaged that the costs of the off-takers for the purchase of electricity from RES under the relevant PPAs at prices

[8] It is to be noted that there was a legal obligation of NEC to subsequently purchase all RES electricity from the other off-takers at the price at which they had purchased it from RES producers. Therefore, ultimately, the off-taker of all RES generated electricity was NEC.

significantly exceeding market prices must be covered ultimately by the end consumers. For that purpose, it was envisaged that the Commission must determine periodically certain fee or price (or a component of the electricity prices) per unit of electricity which must be paid by all end consumers of electricity based on their consumption.

Initially, all electricity generated by a RES facility was to be purchased at the special feed-in tariffs. In 2014 and 2015 the law was changed (including for projects already in operation) with the aim to reduce the quantities to be purchased. Under the new rules only the annual quantities of electricity which were used in the respective calculations for setting the original feed-in tariffs by the Commission are to be purchased at such preferential prices (the so called "net specific generation"). The rest of the electricity is to be purchased by the off-taker at much lower price or sold to the free market. The "net specific generation" was defined as "the average annual electric power generation by 1 kW of installed capacity in accordance with the Commission's decision fixing preferential prices after deduction of the producer's own needs".

In addition, in July 2015 the Energy Act was amended and a special Fund was established – the Electricity System Security Fund" (the "**ESF**"). The cash accumulated by the fund should be mainly used for covering of the expenses of NEC and the end suppliers incurred in relation to the off-take obligations for RES electricity as well as the similar obligations for highly efficient co-generation.

The source of the funds to be accumulated into the ESF are:

- a monthly levy in the amount of 5% payable by all producers of electricity (including RES producers) as well as all by electricity and gas transmission operators and gas storage facilities over their income from sales of electricity (including income from premiums for RES producers) / or respectively - fees for access, transmission or storage (VAT excluded);
- the so called "payments for covering obligations to the society" – i.e. the price or price component which all end consumers must pay to cover the costs of the promotional schemes, in the amounts determined by the EWRC;
- other sources, such as proceeds from sale of CO_2 allowances, etc.

Premiums System

Significant changes to the legal framework on promotion of RES generation were introduced in July 2018, with the aim to foster the energy market liberalization and integrate RES generation into the open market. The changes affect not only RES producers, but also have material effect on the relations between all market participants. The changes remove the "single-buyer model", i.e. NEK is no longer acting as the single off-taker for all RES electricity at preferential prices.

The changes originally affected only generation facilities with an installed capacity of 4 MW or higher but in May 2019 the application of the new regime was widened to cover generation facilities with an installed capacity of 1 MW or higher – the vast majority of local RES projects. For facilities with an installed capacity below 1 MW the original feed-in tariff system was preserved.

Under the new rules the system of purchase of electricity at preferential prices under long term PPAs of the affected producers is terminated. In replacement, the affected producers will be obliged to sell all their energy output at the local electricity exchange IBEX. For the purpose of covering the difference between the previously applicable preferential prices to which RES producers were entitled and the market prices at which they will have to sell their output under the new system, it is envisaged that producers will be entitled to receive "premiums" from the ESF under a contract with the same (the implemented scheme resembles the so called "contract for differences" known to other jurisdictions).

The amount of the premium to be paid by the ESF will be a fixed amount per MWh and it is determined annually by the Commission. For the purposes of determining the amount of the premium, the Commission determines a reference price (named "prognostic market price") for the next 12 months. The reference price is different for the different types of technology (wind, PV, hydro, co-generation, etc.). The Commission then determines the premium as the difference between the preferential price to which each of the RES producers was entitled under the previous feed-in tariff regime and the fixed reference price for the respective technology. The Commission is entitled (but not obliged) to update the reference price and thus the amount of premiums during the 12-month period, but not more often than once per 6 months, if there are significant differences between the actual market prices and the reference price.

Premiums are only payable for the above mentioned "net specific generation" of each facility (as it was for preferential prices under the previous regime) but not for all the energy output of the facility. As a precondition for the payment of the premium, the relevant RES producer must obtain from the Sustainable Energy Development Agency (**SEDA**) the so called "guarantees for origin" for the electricity subject to premium and transfer them to the ESF.

Under the above structure if a particular RES producer is able to sell all its output at the market and achieves market price higher than the reference price, it will receive gross income higher than the previously applicable feed-in tariffs. If, however it is unable to sell all its output, or the sale price achieved is lower than the reference price as established by the Commission, the RES producer will not be fully compensated for the difference between the reference price and the achieved market price. In this case, it will effectively receive gross income lower than under the previous regime.
It is to be taken into account that the ESF is a special entity created with the purpose of the settlement and management of the financial relations related to the promotional scheme for RES generated electricity and other sources (such as highly efficient co-generation). The funds managed by the ESF may not be subject to enforcement and the set-off of obligations of other entities to the ESF against receivables from the fund is prohibited by law. This creates potential risks for RES producers which are entitled to payments for premiums from the ESF. If, for any reason, the sources for funding the ESF are insufficient to cover its obligations for premiums to the RES producers, there will be not effective measures for RES producers to obtain payment and at the same time they will have to continue to make their 5% instalments to the fund.

Guarantees of origin

It should be noted that under the wording of the Renewables Act, the mandatory off-take obligation under the feed-in tariff regime or the obligation to pay premiums under the new premiums regime is conditioned on the issuance of the so-called guarantees of origin[9], issued by the SEDA on a monthly basis. The specific terms and conditions for issuance, transfer and cancellation of certificates of origin are set out in an ordinance of the Minister of the Economy and Energy. In general terms, each month a producer shall submit applications for issuance of guarantees of origin for the electricity produced during the previous month. In addition, reports for the electricity produced shall be submitted each quarter. This means that the relevant off-taker will be obliged to purchase and the ESF will be obliged to pay premiums for only the electricity for which a guarantee of origin has been issued. In this way the Renewables Act assigns an important role to such guarantees of origin (if for some reason the issuance of a guarantee of origin is refused or delayed, the project company will not be entitled to sell the electricity generated) and represents an additional administrative restriction for generation companies. This role goes far beyond the concept of Directive 2009/28/EC which envisages that such instruments will be only used for proving to final customers the percentage or quantity of energy from renewable sources in an energy supplier's energy mix in accordance with Article 3(6)

[9] As envisaged by Article 15 of Directive 2009/28/EC.

of Directive 2003/54/EC (i.e. they are not viewed as a condition for benefiting from the relevant encouragement system of obligatory purchase of electricity at preferential prices) and also that the issuance of such instruments will be only optional and at the request of the generation company.

Access to the grid

RES producers are entitled to priority access to the grid under the RES Act. At the same time, in order to account for the additional costs for ESO for balancing the national system which are generated by intermittent RES producers such as PV and wind facilities, the Commission introduces a special higher fee for access to the transmission grid for such producers. While for ordinary electricity generation facilities the amount of such a fee is BGN 2.12 / MWh (as of July 2019) the special access fee for PV and wind facilities is in the amount of BGN 5.14 / MWh.

7.2.4 Natural gas

Market overview

The Bulgarian natural gas market is still in the process of development and the share of the open market is negligible with 98.90% of the natural gas for local consumption in 2018[10] supplied by the state owned national supplier Bulgargas at regulated prices (the only source of supplies for Bulgargas being its long term supply contract with Gazprom, Russia). The remaining 1.10 % of supplies were realised by traders at free market prices.

The country has a well-developed gas transmission network (mostly built during the socialist era), which is operated by Bulgartransgas – a state-owned company, which is used for internal supplies to distribution companies, large industrial consumers and power plants as well as for transiting gas to Turkey, Greece and Macedonia and supplying. The system is currently underused (due to drastic decline of use of natural gas by industrial companies from the time when the system was built) - about 45 % of capacity of the national transmission system was used in 2018.

Currently, the system is fed almost exclusively with gas from Russia through the Ukraine under long-term supply agreements (local natural gas sources add negligible quantities to the system – less than 1 % as of the end of 2018).

Therefore, after the Russia-Ukraine gas crisis of 2009, which resulted in a cut of supplies to Bulgaria, the government intensified work on building interconnection lines with the systems of Romania, Serbia, Greece and Turkey. Projects for the construction of a terminal for liquefied natural gas ("**LNG**") or use of the existing terminal in Greece as well for supply of compressed natural gas ("**CNG**") from Azerbaijan across the Black Sea have been also discussed, although no practical steps for their implementation have so far been made.

A number of gas infrastructure projects involving the Bulgarian market have been included in the updated list of Projects of Common Interest (PCI) of the European Commission of November 2017.

The market is heavily dependent on imports from Russia which account for almost 99 % of local consumption as of 2018. In previous years local deposits have covered up to 10% of local demand but operating deposits are close to depleted. In 2011 the government granted a permit for exploration of shale gas to Chevron but in 2012 the Parliament imposed a moratorium on the use of "fracking" technologies in Bulgaria and Chevron suspended its activities in Bulgaria. A number of exploration operations in the Black Sea shelf are currently being conducted but far from commercial discoveries at this stage.

Regulatory overview

The natural gas sector is regulated by the Energy Act and a number of Ordinances and Rules issues on its basis by the Council of Ministers and the Commission. This legislation

[10] Data from the Annual Report of the Energy and Water Regulatory Commission of July 2019.

conforms to the fundamental EU guidelines in the sector. Among other things, the law provides for:

(a) the unbundling of services through the establishment of an independent system operator Bulgartransgas which undertook the transportation activities previously performed by the national supplier Bulgargas;
(b) the free development by private investors of transit and gas distribution networks and storage facilities under a licence;
(c) the liberalisation of supply;
(d) third party access to the national transportation system, including storage facilities, on the basis of tariffs approved by the Commission.

For a long time, the local regulatory framework allowing for an actual open market and choice of suppliers by customers was not developed which was a serious obstacle to effective development of free gas market (accompanied by the lack of choice of sources of gas and lack of interconnections). In 2013, on a complaint by one of the major local gas distribution companies, the European Commission opened a case against BEH and its subsidiaries Bulgargas and Bulgartransgas on allegations for hindering competitors from accessing key gas infrastructures in Bulgaria, in breach of EU antitrust rules. In December 2018 the European Commission issued a decision confirming the violations and fined the respondents EUR 77,068,000.

In the context of that procedure and forced by European Regulations for the internal gas market, the local Regulator intensified in the last years the process of preparation of new trading and balancing rules and such were adopted in 2015 and 2016 and substantially amended in 2019 allowing for effective opening of the market and trading.

As of July 2019, a Bill of amendments to the Bulgarian Energy Act was approved in the Parliament with the purpose of setting the legal framework for creating a licensed trading platform (exchange) for gas and assuring liquidity for the same.

Regulated natural gas market activities

According to the provisions of the Energy Act, the supply and distribution of natural gas, as well as the construction and operation of gas transit, transmission and distribution networks and gas storage facilities, are permitted after issuance of a respective licence, which is granted by the Commission.

No licence is required for trading with natural gas including for the import and export of natural gas and that sector is currently open to competition without regulatory barriers. This peculiarity of local regulatory framework is probably due to the marginal current share of the free market (about 1 % of total consumption) due to very limited sources of gas supply and lack of diversified cross-border transportation routes.

The licensing of an organised trading platform is envisaged by proposed changes to the Energy act of 2019.Only one licence for operation of the transmission network (high-pressure pipelines) and for public supply of electricity has been issued for the territory of Bulgaria. Bulgartransgas (under the control of the Bulgarian government) holds the licence for the operation of the national transmission network and Bulgargas (also controlled by the Bulgarian government) holds the licence for the public supply of gas. Bulgartransgas holds also the only currently effective licences for transit of natural gas and for operating a gas storage facility (Chiren).

Similarly, only one licence for operation of a distribution network and for supply of gas to end consumers has been issued for a particular licensed territory. Currently, 24 companies have been issued licenses for distribution of natural gas in regions comprising several towns or within the territory of individual towns.
In principle licences are issued on a "first come, first serve basis" provided that the applicant meets the relevant requirements for obtaining a licence. If there is more than one applicant interested in a particular territory, the Commission must organise a competition procedure for granting the licence.

The initial term of these licences depends on the licensed activity and is up to 35 years. Upon request of the licence holder, the licences may be renewed for the same time period.

Exploration and production

All underground natural resources including hydrocarbons are exclusive public state property. The state provides rights for prospecting and exploration on the basis of a special permit. Rights for the extracting of natural resources are granted by way of a concession. The intensification of local production of gas is one of the priorities of the Bulgarian government. Until now commercial exploitation of local deposits of gas has been modest and has represented less than 10 per cent of local consumption (mainly the Galata deposit, which has been operated since 2004 by Melrose Resources and is now depleted and in the process of being licensed as a gas storage facility).

In 2010 Melrose Resources (now Petroceltic International) received two new concessions for the exploitation of local deposits. As of 2018 however, the local production is marginal – in the range of 120,000 MWh (both for local consumption and exports) which is less than 1 % of local consumption.

The exploration of oil and gas deposits may be carried out only on the basis of an exploration permit issued by the Council of Ministers ("**CoM**") after a proposal by the Ministry of Energy. For that purpose, the CoM institutes a tender procedure and the bidder ranked in first place shall be granted an exploration permit with a term of up to five years (with an option for up to three extensions and the total duration of all extensions can be up to five years, i.e. maximum 10 years in total). Based on the exploration permit the respective bidder concludes an exploration agreement with the CoM outlining the terms and conditions for conducting exploration activities including minimum investments and business programme, fees payable to the government, etc. The exploration rights require its holder to register the geological discovery and commercial discovery of oil and gas deposits. The geological discovery reveals the quantities and qualities of the oil and gas of the respective deposit and the exact location of the deposit, while the commercial discovery contains technical and commercial evaluation of the deposit and proposed methods for extraction of the underground resources.

A holder of an exploration permit which has registered a commercial discovery and has obtained a certificate for that commercial discovery may submit an application to the government for direct (i.e. without conduction of any tender procedure) granting of oil and gas concession within six months as of the issue of the certificate for commercial discovery. If no certificate for commercial discovery has been issued upon expiry of the exploration permit or if the holder of the certificate does not apply for a concession within the 6-month term, the CoM will be free to issue a new exploration permit or an extraction concession for the respective territory following a tender procedure.

After the issuance of a decision of the CoM for granting the concession, the concessionaire shall conclude a Concession agreement for a maximum term of 35 years (which term may be prolonged with up to 15 years). During the concession the concessionaire has the right to extract and process oil and gas from the deposit and to sell the oil and gas products to third parties. The concessionaire is obliged to pay to the state a concession fee (the amount of which is to be determined in the concession agreement), to carry out the annual working programme and to re-cultivate the concession area after the conclusion of the extracting and processing works.

Transmission and access to the system

The national natural gas transportation system (high-pressure pipelines) consists of two independent balancing zones – the national transmission system which is predominantly used for supplies to the local market and the transit transmission system, which is predominantly used for transit of gas from the border with Romania to Turkey, Greece and Macedonia under long term supply contracts with Gazprom. The two systems have two interconnection points so physical exchange of gas between the two is possible. Both systems are owned and operated by Bulgartransgas. Bulgartransgas is also owning and operating the single local gas storage facility Chiren.

Currently, there are a number of exit/entry points to the national system: one exit/entry point from the Romanian transmission system supplying Russian gas through the Ukraine, the exit/entry point to the gas storage facility Chiren, an exit/entry point at the interconnector with Romania Rousse-Giurgiu (until certain improvements of the system on Romanian territory are made, as of 2019 the interconnector provides unidirectional transmission to Romania only) and two entry points connecting local deposits.

The transit system has the following interconnection points: one exit/entry point with the Romanian transmission system, an exit/entry point with the Greek transmission system and two exit points to the transmission systems of Macedonia and Turkey (in 2019 certain plans to refurbish the interconnection facilities with Turkey in order to allow for a reverse flow of gas were announced). As mentioned, a number of interconnection lines with the systems of neighbouring Greece, Turkey and Serbia are in process of development which will substantially diversify the transmission opportunities of the system.

By law Bulgartransgas and the licensed regional distribution companies are obliged to allow free and non-discriminatory access to the transmission systems to all users (consumers, traders, local producers and licensed owners of gas storage facilities) under terms and conditions established by Rules adopted by the Commission and pursuant to access agreements under general rules approved by the Commission. The fees for access and transmission are determined by the Commission. Access to the system may be refused only on technical reasons - lack of capacity or hazard to the integrity and security of the transmission system. Refusal for access on the basis of potentially serious economic and financing difficulties for another user of the system due to contracts containing 'take or pay' clauses is also possible, but only on the basis of an express derogation issued by the Commission, which must be notified to and is subject to control by the European Commission. The same obligation to provide access applies to the operators of gas storage facilities.

Trading and supply

The prices under which the public supplier of natural gas supplies the final suppliers and customers are approved by the Commission. The prices at which final suppliers supply protected consumers are also approved by the Commission and transactions are concluded under general terms approved by the Commission. All other transactions are concluded at market prices under Rules approved by the Commission. The transmission system operator (part of Bulgartransgas) is responsible for the balancing and administration of the transactions. Although in theory the market is fully liberalised, virtually all supplies to large consumers are performed by the public supplier Bulgargas with few deals realised between industrial consumers and the operator of local deposits and traders.

It is expected that the liberalised market will grow significantly in the next years. As of July 2019, a Bill of amendments to the Bulgarian Energy Act was approved the Parliament with the purpose of setting the legal framework for creating a licensed trading platform (exchange) for gas and assuring liquidity for the same.

LNG and storage capacity

There are no operating LNG terminals in Bulgaria. The government has discussed ideas for the construction of a local LNG terminal or signing arrangements for the use of the existing LNG terminal in Greece for supplies to Bulgaria, but no specific steps have been taken so far.

7.2.5 Upstream and the oil market

Market overview

Currently, the local production of oil in Bulgaria is negligible and virtually 100 per cent of oil is imported from Russia. In the last year the government has prioritised the exploration for local oil and gas deposits and has issued a number of explorations permits to international companies hoping to increase domestic production.

Regulatory overview

In respect of the legal regime for oil exploration and production, please refer to Section 4.4 above.

7.2.6 Forthcoming developments in the Bulgarian energy sector

Major investment opportunities are expected in the Bulgarian energy sector in the next years in many different areas.

Nuclear energy
The project for the construction of a new Belene NPP (two 1000 MW units) was officially restarted by the Bulgarian Government and Parliament in 2018 and in 2019 an international procedure for selecting a co-investor for the completion of the project was initiated. The project is expected to cost over EUR 10 billion and could reshape the local and regional electricity market.

Renewable energy
Investments in new project have been effectively halted in last years. However, there is quite active market for existing projects in operation and it may be expected that this market will further grow after the new promotional schemes introduced in 2018 and 2019 are tested and investors obtain actual data about how the project financials perform in the new environment. In the context of declining costs of renewable energy technologies and rising electricity prices and CO_2 emissions costs potential may appear for development of new projects without subsidies.

New gas burning co-generation facilities
Apart from certain district heating and industrial co-generation facilities there are no major local gas burning generation facilities. With Bulgarian coal power plants facing serious issues with CO_2 emission costs and increased restrictions for air pollutant emissions and the rising importance of natural gas as a transition fuel, opportunities are appearing for new gas burning generation facilities in Bulgaria particularly co-generation facilities for district heating or industrial purposes.

Electricity and gas markets liberalisation
The liberalisation of the local electricity and gas markets despite speeding up in last years is yet far from the level of matured markets. It is expected that measures for boosting free trade in both markets will continue which will bring significant opportunities for electricity and gas trading including cross-border.

Major gas infrastructure projects
Bulgaria has the chance to strengthen its position as a local energy hub. A number of gas infrastructure projects involving Bulgaria have been included in the updated list of Projects of Common Interest of the European Commission of November 2017.

Oil and gas
Further increase of local production of natural gas and oil is one of the priorities of the Bulgarian government in the aims of ensuring the security of ***supplies*** and a certain level of independence from imports of hydrocarbons. Therefore, the government continues to implement its plans to attract major investments by international companies in exploration activities.

7.2.7 Impact of the coronavirus pandemic on energy and infrastructure[11]

A. Covid-19 Response Investment and Support Initiative – General

EU Funding

In the context of the CRII Bulgaria is allowed to retain as immediate liquidity for Covid-19 response measures EUR 122 million of unspent pre-financing from the EU's cohesion funds and could benefit from EUR 690 million of co-financing from the EU budget if such unspent amounts are effectively used – i.e. a total of EUR 812 million as fresh money from the EU budget. In addition, Bulgaria would be allowed to reprioritise and use for Covid-19 response measures EUR 546 million of cohesion funds that have not been contracted for the budgeting period 2014-2020.

A state of emergency was introduced in Bulgaria by a decision of the Parliament of 13 March 2020 (originally with a duration until 13 April 2020, subsequently extended until 13 May 2020) and a special Act on the Measures and Actions during the State of Emergency was adopted on 23 March 2020, effective as of 13 March 2020 (the "State of Emergency Act"). The State of Emergency Act introduced certain general rules and amendments to national legislation on EU funds' spending which will be applicable during the duration of the state of emergency and which provide for flexibility and simplified rules for allocation of funds for Covid-19 response measures. In particular, grants can be awarded for eligible Covid-19 response measures without a prior invitation for collecting offers and/or under reduced time periods, with a simplified process for approval. There is, however, no public information so far on particular measures and programs made available by the government to the business in the CRII context. Funds have been so far allocated mostly to public entities for spending on health systems related measures (such as protective equipment and medical supplies, supplemental payments to health workers involved in Covid-19 response activities, etc.).

Covering of salary expenses

A general economic support measure to be made available in Bulgaria includes partial covering of salary expenses for employees of enterprises affected by the pandemic. Under that measure, for a period of up to three months, the National Social Security Institute will cover to eligible employers upon their request 60% of the amount of the individual social insurance income for January 2020 and the social security contributions due by the employer for certain of its employees, based on criteria adopted by the Bulgarian government.

According to a relevant Decree of the Council of Ministers, the possibility for companies to claim the above support is available for:

(i) employees whose work was suspended on the basis of government authority in relation to the state of emergency;
(ii) employees whose work was suspended on the basis of an order of the employer in relation to the state of emergency;
(iii) employees whose working hours have been reduced on the basis of an order of the employer in relation to the state of emergency.

The availability of aid is subject to a number of exceptions and conditions. The aid under item (i) above is available only to employers of certain sectors directly affected by governmental measures such as retail outlets, air and road transport, hotels and restaurants, cultural, sports and educational institutions, etc. The other types of aid are available generally to all economic sectors except for agriculture, forestry and fishery, financial sector, educational sector, health sector. The effective implementation of the measure will start upon state aid approval by the European Commission which is still pending.

Intermediated SME Loan Guarantee Program

The government injected BGN 500 million (EUR 255 million) as a capital increase of the state-owned Bulgarian Development Bank AD (the "BDB"). The BDB will use these funds to provide public guarantees on investment loans and working capital loans by private banks to

[11] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

micro, small and medium-sized companies affected by the Covid-19 outbreak in Bulgaria. The scheme aims at limiting the risk associated with issuing loans to those companies that are most severely affected by the economic impact of the current crisis. The measure has been cleared by the European Commission under EU State aid rules on 8 April 2020 and the BDB is to publish shortly the particular terms and conditions for the implementation of the measure.

Financing repayment moratorium

Under recent amendments to State of Emergency Act (effective as of 9 April 2020), the effects of a default on payments of private debtors under loan agreements or agreements for other forms of financings (factoring, forfeiting, etc.) provided by banks and financial institutions (including when the financing receivables have been transferred to other entities), as well as under lease agreements are suspended for the period of the state of emergency. This includes the accrual of interest and penalties for delay, acceleration, and the right to rescind a contract and repossess assets.

At the same time, in compliance with the Guidelines on legislative and non-legislative moratoria on loan repayments applied in the light of the Covid-19 crisis adopted by the European Banking Authority, the Bulgarian National Bank has approved general terms for a non-legislative (voluntary) bank loans repayment rescheduling schemes. Pursuant to the approved terms, banks that have declared to the BNB that they would join the scheme can agree with borrowers affected by the Covid-19 outbreak on the rescheduling of loan repayments (choosing from three types of rescheduling plans) for up to six months on loans contracted before 31 March 2020. So, rescheduled debts will not be considered as non-performing loans for banks' solvency purposes.

Tax measures

Under the State of Emergency Act, the deadlines for submission of returns and payment of certain alternative and one-off corporate taxes and local municipal taxes have been postponed to June 2020. The rules for advance corporate income tax instalments in 2020 have been revised to provide more flexibility to companies to account for the effects of the economic slowdown as a result of the Covid-19 outbreak. No new enforcement proceedings for tax and other public debts are to be initiated until the end of the state of emergency, subject to limited exceptions. All existing enforcement procedures are suspended, subject to limited exceptions.

B. Impact on the Energy and Infrastructure Sectors

No major regulatory changes have been introduced in the energy sector as a result of the Covid-19 outbreak in Bulgaria. The economic slowdown and the closure of many industrial and service provision facilities caused by the Covid-19 restrictions naturally affected the energy markets with electricity prices at the Bulgarian exchange dropping by about 30% in the last two weeks of March compared to the same period of 2019. However, the volumes of electricity consumption were only slightly affected and there were no major dropdowns in consumption like those recorded in some other European countries.

In view of the expected economic slowdown and for the purposes of public expenditures control and reprioritization, proposals on postponing certain large energy infrastructure projects such as the Belene Nuclear Power Plant project and the Balkan Stream gas pipeline project have been made public but for the time being no official position of the government has been made. In the meantime, the terms under the procedure for the selection of a strategic investor for the Belene NPP project have been suspended for the period of the state of emergency. It could be expected that the redirecting of grants from EU funds to Covid-19 related measures would affect the financing and implementation of large roads and other public infrastructure projects but no official data is available at this stage. In accordance with the State of Emergency Act, all electricity grid operators should discontinue all planned maintenance involving interruption of electricity transmission, with the exception of emergency repairs.

The periods for payment of electricity bills by household customers, as established in the approved general terms of the relevant suppliers, are extended from 10 days to 20 days and may be extended further by an order of the Minister of Energy upon recommendation of the national emergency committee after considering the impact on the financial status of electricity suppliers and the security of supplies.

All utility companies must operate their customer service centres in strict compliance with the relevant requirements of the national emergency committee. Employees of all utility companies traveling on business are exempted from travelling restrictions which are otherwise applicable under the relevant pandemic measures. All healthcare establishments, state institutions and companies in the telecommunications sector are required to make urgent preventive checks of their reserve electricity supply systems and capacities aimed at assuring uninterrupted electricity supplies for their operations and must inform the Ministry of Energy of the results, without delay.

7.3 CROATIA

7.3.1 Introduction to the energy market

Croatia has, within the past decade and especially in the past couple of years, seen vivid development of the energy sector, in all of its areas such as electricity and gas markets, renewables and upstream regulation and activities.

Legislative framework of the energy sector in Republic of Croatia ("**RoC**") develops in the direction set by the obligations assumed by international agreements in fields of energy, environmental protection and climate, by the ever-present obligation to harmonize Croatian energy legislation with the European acquis in this area, within the EU membership, as well as by the real need to regulate relations between energy market stakeholders in line with the demands of economic, energy, environmental and social policies at European and national level. Croatian energy legislation is continuously harmonized in line with the European acquis requirements, by updating its existing legislation, or by adopting new energy laws and regulations necessary for the transposition.

Apart from becoming a member of the EU internal energy market which to a certain extent applied even before the accession as a result of the Ratification and Accession Treaty signed in 2001, by ratifying the Energy Charter Treaty, Croatia has undertaken to comply with the principles of market economy in the energy sector, enhancing energy efficiency and environmental protection. Also, by ratifying the Kyoto protocol, it has undertaken to ensure that 20 per cent of all energy consumed in Croatia comes from renewable energy sources. Consequently, in the last few years Croatia has been experiencing development of renewable energy projects such as wind, solar and biomass power plants, etc. It's important to mention that Croatia's share of renewable energy sources already stands at 29% . Therefore, Croatia has exceeded the 20% target level in the total energy consumption, the European Union has set for 2020.

The energy sector is the largest source of greenhouse gas emissions, and climate change is one of the most important threats to modern mankind. Global challenges and instruments (like the United Nations Millennium Development Goals and Paris Accord) and EU policies (mostly in the energy Union framework) create the framework for the development of energy policies in Croatia.

Owing to the Paris Accord, global efforts are aimed at reducing greenhouse gas emissions, aiming to keep Earth's average temperature rise below 2° C and preferably below 1.5° C. Europe already has and wants to keep the leading role in the global climate change struggle, as a consequence thorough changes are needed within the energy sector. The Republic of Croatia, as an EU Member State, participates in the adoption and implementation of EU common policies, including the energy policy. The Ministry of Environment and Energy initiated the process of drafting the Energy Development Strategy of the Republic of Croatia by 2030 with a view to 2050 - an advisory document containing ideas, suggestions and possible directions for development of the energy sector. Said document serves to encourage debate and collect contributions from all stakeholders, a so-called Green Book. The premises, analyses and results presented in the Green Book constitute the basis for public discussion and rethinking of the changes that are taking place and will transform the energy sector and the use of energy in the coming decades. Changes are expected in the legal framework, sector structuring, business operations, system management, implementation of new technologies, construction of new infrastructure and strengthening the position of the end-users.

Ministry of energy, the regulatory agency and regulated subjects i.e. companies as service providers that were granted special position in the legal system of the Republic of Croatia ("**RoC**" or "**Croatia**"), constitute the unique institutional framework of the energy sector of RoC. These are as follows.

The central administrative body responsible for energy is the Ministry of Environment and Energy ("**Ministry**"), entrusted with activities of defining and implementing energy policy, strategic planning and development of the energy sector, security of energy supply in RoC, drafting legislative proposals and regulations in the field of energy, issuance of energy approvals, record keeping, supervision, international cooperation and representation of RoC in professional and advisory bodies in the EU as well as other professional and administrative activities. The Ministry was conferred with said activities by the Energy Act (Official Gazette No. 120/12, 14/14, 102/15, 68/18 of 27 July 2018) and accompanying sectoral acts and regulations.

The Croatian Energy Regulatory Agency ("**HERA**") is the body in charge of regulating all energy activities in Croatia and has its own budget, whose revenues consist of remuneration for conducting energy regulatory activities. HERA is established as an independent and non-profit legal entity with public powers for the purpose of determining and implementing the regulation of energy activities in the electricity, heating, gas and petroleum sectors. HERA is responsible to the Croatian Parliament by submitting a yearly report on its activities.

Croatian Agency for Mandatory Oil and Oil Derivatives Supplies ("**HANDA**") was merged into the Agency for Hydrocarbons ("**CHA**"), by Amendments and supplements to the The Petroleum and Oil Products Market Act (Official Gazette No. 19/2014, 73/2017 of 27 July 2018). CHA, as the central body in RoC for compulsory supplies of oil and oil derivatives, is the only body obliged and authorized to form, maintain and sell mandatory supplies of oil and oil derivatives.

The supplies are used in the case of certain disturbances in the market supply of oil and oil derivatives in RoC along with the fulfilment of RoC's international obligations, based on decisions of the International Energy Agency and the European Commission, to release compulsory supplies of oil and oil derivatives.

Croatian Energy Market Operator ltd. ("**HROTE**") provides public service of organizing the electricity and gas market, under the supervision of HERA.

[12] EUROSTAT

[13] HERA's primary activities are; issuance of licenses for carrying out energy activities, adoption of methodologies for the determination of tariff items in tariff systems, prescribing fees and supervision of their application, granting status of eligible electricity producers, approval of development and network construction plans, sectoral legislative activities, giving expert opinions or approvals for energy sector acts and regulations and supervising the work and quality of service provided by regulated subjects.

During the reconstruction of the Croatian power sector, Croatian Transmission System Operator ltd. ("**HOPS**") was established as an independent legal entity. HOPS is the only transmission system operator in RoC and the owner of the entire Croatian transmission network with the license to carry out energy transmission activities as a regulated public service.
Croatian Power Exchange ltd. ("**CROPEX**") is the central venue of organized electricity trading between market participants and stock exchange members, that assumes the risk of purchasing and selling electricity through closed stock exchange transactions.

HEP-Distribution System Operator ltd. ("**HEP ODS**") is a company within the HEP Group . HEP ODS has 21 distribution areas on the RoC territory. For the needs of network users, HEP ODS provides power distribution services that include network access and network usage. HEP ODS is responsible for the quality of the delivered electricity to all end customers and it guarantees steady supply electricity. It also conducts, maintains, builds and develops distribution network and ensures long-term network capabilities to meet future network access requirements.

HEP ELEKTRA ltd. is the only energy company authorized to provide public electricity supply services in RoC, for households as well as for business entities. It is a company within the HEP Group.

The Plinacro Group consists of: 1. PLINACRO ltd., the parent company, 2. Underground gas storage ltd., a subsidiary owned by the parent company since 2009 and 3. LNG CROATIA LLC, as a jointly controlled entity together with HEP d.d. PLINACRO ltd., as the operator of the gas transportation system in RoC, according to the provisions of the Gas Market Act (Official Gazette No. 18/18 of 23 February 2018), is responsible for the management, maintenance and development of the gas transportation system, all to ensure reliable and steady gas delivery.

In RoC, the activity of oil transportation through a pipeline is carried out by the Adriatic Pipeline d.d. ("**JANAF**"), which is obliged to provide access to the transportation system in an impartial and transparent manner to natural persons and legal entities, in accordance with the Petroleum and Oil Products Market Act (Official Gazette No. 19/4, 73/17 of 26 July 2017). In addition to oil transportation, JANAF's significant activities include; storage of oil and oil derivatives and transhipment of liquid cargo. The JANAF system was built as an international oil transportation system from Omišalj Port and Terminal, to domestic and foreign refineries in eastern and central Europe.

LNG CROATIA LLC is a company founded with the intent to build and manage the infrastructure necessary for the reception, storage and gasification of liquefied natural gas.

7.3.2 Electricity

Market overview

The performance of energy activities and the legal status and responsibilities of the participants in the electricity market are determined by the Energy Act (Official Gazette 120/2012, 14/2014, 95/2015, 102/2015, 68/2018 of 27 July 2018), ("**Energy Act**"), Electricity Market Act (Official Gazette No. 22/2013, 95/2015, 102/2015, 68/2018 of 27 July 2018), ("**Electricity Market Act**") and regulations adopted for their implementation.

Electricity Market Act distinguishes six types of energy activities within the electricity sector – production of electricity, transmission of electricity, distribution of electricity, organisation of electricity market, supply of electricity and trade of electricity. Only the energy operators holding energy licences

[14] Hrvatska elektroprivreda (HEP Group) is the national energy company, which has been dealing with generation, distribution and supply of electricity for more than a century. The parent company (parent body) of HEP Group is HEP d.d., which carries out the function of corporate governance of HEP Group and guarantees conditions for safe and reliable electricity supply to customers. Croatian transmission system operator (HOPS) has been unbundled from HEP Group, according to ITO model (Independent Transmission Operator).

issued by HERA are entitled to undertake the mentioned energy activities.[15]

As at 1 April 2019[16], the following market participants were registered as holders of energy licences for undertaking specific energy activities in the RoC[17]:

(a) for production of electricity – 55 different companies;
(b) for transmission of electricity – Hrvatski operator prijenosnog sustava d.o.o. – HOPS d.o.o., owned by HEP d.d., a 100 per cent state-owned company;
(c) for distribution of electricity – HEP-Operator distribucijskog sustava d.o.o. – HEP ODS, owned by HEP d.d.;
(d) for organisation of electricity market – HROTE;
(e) for electricity supply – 15 different companies;
(f) for electricity trading – 33 different companies;

All legislation within the energy sector was significantly changed in the period from 2014 to 2019, and further modification is expected to continue, since the energy sector represents the most important part of economic growth in the RoC.

The Croatian electricity market is only partially liberalised. Non-liberalisation exists, from both the legislative and market points of view, in relation to electricity transmission and distribution.

CROPEX was incorporated in May 2014 and become officially operational on the 10 February 2016. This represents a step towards the cooperation of the Croatian electric energy market with other markets in the area. It is also significant for the development of different cross-border transmission mechanisms. In June 2018, HOPS and CROPEX formally linked the Croatian electricity market to the European Multiregional Electricity Market, which was a first successful project of this kind for RoC. This was the very first introduction of the cross-border capacities with the ultimate goal to connect RoC with neighbouring wholesale electricity market.

Regulatory overview

Electricity Market Act secures implementation of the following directives in the Croatian legislative framework:

(a) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC;
(b) Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC; and
(c) Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment.

The Electricity Market Act secures implementation of the following regulations in the Croatian legislative framework:

(a) Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency;
(b) Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management;
(c) Commission Implementing Regulation (EU) No 1348/2014 of 17 December 2014 on data reporting implementing Article 8(2) and Article 8(6) of Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency.

[15] Certain exceptions do exist primarily in relation to the production of electricity wherein, in certain circumstances, legal or private persons will not be obligated to obtain the energy license. In addition, with respect to undertaking of some of the activities such as supply and trading, among other, additional requirements are to be complied with – obtaining of EIC sign – Energy Identification Coding Scheme, entering into an Energy balancing agreement with HOPS d.o.o., and other various agreements.

[16] Information is available on the HERA's website – https://www.hera.hr/hr/html/dozvole.html

[17] Wherever an energy activity is undertaken by more than three energy operators, only the number and not the names of such operators is given.

Apart from the Electricity Market Act and Energy Act, electricity activities in Croatia are mainly regulated by the following Croatian acts and regulations:

- Statute on Licences for Undertaking Energy Activities and Keeping the Registry of Issued and Revoked Licences for Undertaking Energy Activities (Official Gazette No. 88/15, 114/2015, 66/18) ("**Statute on Licences**");
- Act on renewable energy sources and high efficiency cogeneration (Official Gazette No. 100/15, 123/16, 131/17, 96/18, 111/18);
- Electricity Market Act (Official Gazette No. 22/13, 95/15, 102/15, 68/18);
- Act on Regulation of Energy Activities (Official Gazette No. 120/12, 68/18);
- Grid Rules of Transmission System (Official Gazette No. 67/17);
- Grid Rules of Distribution System (Official Gazette No. 74/18);
- Regulation on Issuing of Energy Licences and Determining the Conditions and Deadlines for Connecting on the Electro-energy Grid (Official Gazette 7/18);
- Methodology for Determination of Tariff Items for Guaranteed Supply with Electricity (Official Gazette No. 20/19);
- Methodology for Determination of Tariff Items for Supply with Electricity as Universal Service (Official Gazette No. 116/13, 38/14);
- Decision on Amount of Tariff Items for Guaranteed Electricity Supply (Official Gazette No. 25/19);
- Decision on Amount of Tariff Items for Distribution of Electricity (Official Gazette No. 112/18);
- Decision on Amount of Tariff Items for Transmission of Electricity (Official Gazette No. 112/18);
- Decision on Determining the Body Responsible for Coordination of Procedures for Issuing the Permits for Projects of Common Interest in the Energy Sector (Official Gazette No. 137/14, 31/17);
- Decision on Reimbursement for Renewable Energy Sources and High Efficiency Cogeneration (Official Gazette No. 87/17);
- Statute on Usage of Renewable Energy Sources and Cogeneration (Official Gazette No. 88/12, 120/12, 100/2015, 116/18);
- Decree on Incentives to Promote Electricity Production from Renewable Energy Sources and High Efficiency Cogeneration (Official Gazette No. 116/18);
- Decree on the Share of the New Electricity Delivered by Eligible Producers that the Electricity Suppliers are Required to Take Over from the Electricity Market Operator (Official Gazette No. 116/18);
- Statute on Acquisitions of Eligible Electricity Producer Status (Official Gazette No. 132/13, 81/14, 93/14, 24/15, 99/15, 110/15);
- Decree on Criteria for Obtaining Status of Vulnerable Energy Customers from Connected Systems (Official Gazette No. 95/15);
- Decree on Monthly Amount of Compensation for Vulnerable Energy Customer, Method of Participation in Settling Energy Costs for the Customer and Procedures of Responsible Centres for Social Welfare (Official Gazette No. 140/15);
- Tariff System for Production of Electricity from RES and Cogeneration (Official Gazette No. 33/07, 63/12);[18]
- Tariff System for Production of Electricity from RES and Cogeneration (Official Gazette No. 63/12, 120/12, 121/12, 144/12, 133/13); [19]
- Tariff System for Production of Electricity from RES and Cogeneration (Official Gazette No. 133/13, 151/13, 20/14, 107/14, 100/15, 100/15); [20]
- Decree on Establishment of Guarantees of Electricity Origin (Official Gazette No. 84/13, 20/14, 108/15);
- Methodology on Establishment of Electricity Origin (Official Gazette No. 133/14);
- Decision on the Reimbursement Amount for Participation in the System for the Guarantee of Electricity Origin (Official Gazette No. 34/15);
- Rules on Organizing of Electricity Market (Official Gazette No. 121/15, 48/16, 50/18);
- Rules on Balancing of Electro Energy System

[18] This act is applicable only in relation to projects that signed FiT PPA prior to 6 June 2012.
[19] This act is applicable only in relation to projects that signed FiT PPA prior to 1 January 2014.
[20] This act is applicable only in relation to projects that signed FiT PPA prior to 1 January 2016.

(Official Gazette No. 133/06, 135/11);
- Rules on Changing the Energy Supplier (Official Gazette No. 56/15, 33/17);
- Criteria on Issuing the Approval for Construction and Operation of Direct Lines (Official Gazette 43/17);
- Methodology for Determination of Prices for Calculation of Balancing Electricity (Official Gazette No. 71/16, 112/16);
- Methodology for Determination of Prices for Providing of Balancing Services (Official Gazette No. 85/15);
- Decision on the Amount of Fees for Grid Connection and Increase of Connecting Power (Official Gazette No. 52/06);
- Methodology for Determination of Fees for Electro-energy Grid Connection of New Grid Users and for Increasing the Connecting Power for Existing Grid Users (Official Gazette No. 51/17, 31/18);
- Decision on the Fee for Organising of Electricity Market (Official Gazette No. 94/07, 38/12);
- Decision on the Fee Amount for Using the Premises Used by Production Plants to Produce Electricity (Official Gazette No. 84/13, 101/13, 72/15);[21]
- Decision on the Amount of the Fees for Undertaking Works of Regulation of Energy Activities (Official Gazette No. 155/08, 50/09, 103/09, 21/12);
- Conditions on Quality of Electricity Supply (Official Gazette No. 37/17, 47/17, 31/18);
- General Conditions for Grid Use and Supply of Electricity (Official Gazette No. 85/15); Decision on the Reimbursement Amount for Participation in the System for the Guarantee of Electricity Origin (Official Gazette No. 34/15) ;
- Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action.

Regulated electricity market activities

The Electricity Market Act differentiates between the market-based and regulated energy activities. Regulated activities are undertaken as public services. Such activities are transmission and distribution of electricity, organisation of electricity market, which is undertaken by HROTE, and the supply of electricity in the amount and manner prescribed by the law. Other energy activities are performed as marked/based activities which are regulated by the market itself.

Material provisions of electricity market law and licensing regulations

The Statute on Licences regulates requirements which any energy operator undertaking an energy activity is obliged to meet. These requirements are specific to the type of energy activity. According to the Energy Act, all energy entities must meet the following requirements:

(a) be registered for undertaking the respective energy activity in theRoC;
(b) have sufficient technical qualifications for undertaking the subject activity;[22]
(c) prove employment of sufficient number of employees professionally qualified for undertaking of the subject activity;
(d) hold sufficient financial means necessary for undertaking of the subject activity or a proof of their capability to obtain one; [23]
(e) not to have any energy licence for undertaking of the subject energy activity revoked from the entity in the five years preceding the submission of the request;
(f) that the members of the management board or other responsible persons within the entity have not been convicted of a crime in an economic sector in the last five years, or that the natural person seeking the licence have not been convicted of a crime in an economic sector in the last three years.

[21] Croatian agencies and bodies competent for providing and regulating energy services issue publications with regard to the specific areas of energy services' provision (e.g. amount of tariff items, HOPS non-standard service fees, usage of the certain registries etc.). Such publications are regularly updated to be in compliance with the relevant legislation (e.g. the Energy Market Act).

[22] Specific technical qualifications are set forth for each type of energy activity with the Statute on Licences. This applies to the human resources and financial obligations requirements also.

[23] The energy licence holder (entity) needs to have sufficient financial means as determined by law or a proof of its capability to obtain such means in the following amounts: HRK 50,000 (approx. EUR 6,600) for production of electricity, HRK 300,000 (approx. EUR 39,500) for distribution, HRK 100,000 (approx. EUR 13,200) for transmission, HRK 20,000 (approx. EUR 2,650) for trade, and HRK 30,000 (approx. EUR 4,000) for supply of electricity.

Moreover, HERA may issue a licence to the entity which does not meet the aforementioned criteria if the entity is a holder of a project of a common interest, which has been listed on a list of projects of the common interest of the European Union.

Transfer of energy licence is regulated under the Statute on Licences. It stipulates the possibility to transfer the energy licence only in cases of spin-off of an energy licence holder, or its merger to or with another legal entity. In the event of spin-off and merger, the transfer of energy licence is possible to only one legal entity which is the universal successor of the energy licence holder in question, subject to the filing of the request for such transfer to HERA within the timelines specified in the subject statute.

Trading and supply of electricity

As previously mentioned, energy activity may be undertaken by a natural or legal person that has obtained an energy licence from HERA. Up-to-date practice of HERA was to issue energy licences only to those natural or legal persons registered for the undertaking of energy activities in the RoC (such registration in relation to the legal persons would imply a registration of undertaking energy activity as a business activity of such legal person in the court registry of the respective commercial court in the RoC).

In accordance with the new Electricity Market Act, the supplier or trader of electricity coming from the EU Member State or from the Energy Community member state wishing to participate in the electricity market of the RoC, as a supplier or trader, is also obligated to obtain respective energy licence from HERA. As of 2016 HERA may issue an energy licence to the trader or supplier of electricity coming from the EU and/or Energy Community member state under more simplified rules in line with the Statute on Licences. The logical interpretation of this provision would be that foreign entities from the EU and/or Energy Community member states will be allowed to undertake energy activities in the RoC subject to obtaining energy licence from HERA, without any type of establishment in the RoC. In line with the abovementioned, the Statute on Licences, allows HERA to issue a licence to an active trader from the EU and/or Energy Community without the need for establishing a branch office.

Therefore, the provisions of this statute enable foreign entities from the EU and/or Energy Community Member States to undertake energy trading activities in RoC without any type of establishment in the RoC, after obtaining a licence from HERA. Nevertheless, this provision may be in contradiction with the provision of the Croatian Companies Act (Official Gazette No. 111/1993, 34/1999, 121/1999, 52/2000, 118/2003, 107/2007, 146/2008, 137/2009, 111/2012, 125/2011, 68/2013, 110/2015 of 13 October 2010) according to which anyone who wishes to undertake permanent business activities in the RoC shall be obliged to establish a branch office at least. From HERA's publicly available registry, it seems that on the Croatian market there are indeed traders and suppliers with the registered seat in other countries in the EU and/or Energy Community.

Finally, according to the Electricity Market Act, the electricity market consists of retail and wholesale electricity market, whereas the wholesale market consists of "bilateral agreements market", "energy balancing market", and "electricity stock market". HROTE and HOPS are responsible for organizing the stock electricity market for physical trading with electricity on the whole territory of the RoC, and for the connection with other stock electricity markets. Croatian electricity stock market known as CROPEX is a central counter party (CCP) between the sellers and buyers of electricity.

The existing Croatian legislation differentiates between the electricity consumers entitled to choose their own supplier and paying the price of electricity determined by the market on the one hand, and the electricity consumers entitled to the electricity supply provided as public service, on the other hand. The "public service supply" is undertaken as regulated service, under the regulated prices. Furthermore, the Electricity Market Act differentiates between the (i) public service supply as universal service established for the need of households and the (ii) public service supply as guaranteed service which is, according to its statutory definition, applied when an end consumer, under certain circumstances, remains without a supplier.

According to the Electricity Market Act, the Government of RoC determines those energy operators that are (in line with the provisions of the Electricity Market Act) obligated to provide a service of electricity supply as universal service or as guaranteed supply on the territory of the RoC. Such energy operators are obligated to procure the electricity needed for a safe and continuous electricity supply from the producers, traders, other suppliers, and the organized electricity market or from import, wherein the priority is given to the electricity produced from renewable energy sources and cogeneration.

Transmission and grid access

There are only one transmission system operator and one distribution system operator in Croatia, respectively HOPS and HEP-ODS. They are a part of a vertically integrated company – HEP Group and are independent from one another with respect to their form, organisation and decision making.

One of the most important aspects of the transmission system is the execution of unbundling by choosing one of the possible models. Both the Directive 2009/72/EC and the Electricity Market Act recognize three types of models: ownership unbundling, ISO – Independent System Operator and ITO – Independent Transmission Operator models. The Croatian legislator has opted not to impose any of the models onto the transmission system operator but has rather left it to the vertically integrated company – HEP d.d., initial owner of the network system, to choose the model.

The grid connection agreement is concluded between the grid system operator and the producer of electricity in accordance with the Statute on Issuance of the Energy consents and Determination of Conditions and Deadlines for connection to the Electro Energy Grid. The connection fee is payable by the producer and covers the costs of the connection construction and securing of adequate technical conditions of the grid. The grid usage agreement is concluded between the grid system operator and the owner (or a holder of other in rem rights) of the building or a part of the building which is connecting to the grid. Such agreement governs the terms and conditions of the grid usage and is usually made for an indefinite time period.

General approvals and permits for electricity generation facility project implementation

There is a set of interdependent regulatory steps essential to the constructing and running of an electricity generation facility. Apart from the energy licence issued by HERA, each electricity generation facility construction also requires energy approvals (a requirement in addition to the regular construction-permitting process). Before obtaining the necessary approvals and licences, a new company has to be incorporated or the existing company's incorporation deed needs to be changed; in both cases, the generation of electricity as a business activity of the company must be registered with the court registry of the respective commercial court. Also, in the events of renewable electricity generation, the investor/project developer should choose the appropriate project site bearing in mind the investment feasibility with regards to the optimal usage of a specific RES, and difficulties regarding the grid connection, both of which depend on the location of generation facility. Also, the investor's decision on the location should be based on the respective construction possibilities provided for in the spatial plans, current land ownership status, as well as on other technical and economic factors.

Please note that the list of necessary licences and approvals will also include those approvals required for the renewable electricity generation facilities[24].

Licences and approvals

(a) Location permit is issued by the local government where the facility is to be constructed or by the Ministry of Construction and Spatial Planning (in case of a facility with more than 20 MW). Location permit is issued in cases such as those when construction is scheduled in phases (*fazna izgradnja*) and/or in stages (*etapna izgradnja*), or in case of unresolved property relations, or when expropriation is needed, etc.
(b) Securing the Grid Access – during the location permit issuing process, a grid connection agreement or pre-agreement is concluded.
(c) Energy approval – the energy approval is a requirement for the construction of the facility. It is a precondition for the issuance of the construction permit.
(d) Construction Permit – must be obtained within 2 years as of the validity of the energy approval.
(e) Preliminary Eligible Producer Status applies to renewable electricity generation facility and cogeneration heating plants only. IT (eventually) shall give its holder the right to a FiT price for produced electricity[25].
(f) Electro energy approval ("**EEA**") is a precondition for the grid connection of the generation facility.
(g) A usage permit is issued by the same body which issued the construction permit, once the construction is complete. It is a precondition for the usage of the facility. The usage permit confirms that the construction has been completed and that it fully complies with the construction regulation.
(h) The energy licence entitles its holder to undertake energy activities. It is issued by HERA which also keeps a registry of the issued energy licences.
(i) Eligible Producer Status ("**EP Status**") is preconditioned by the issuance of the energy licence, valid usage permit and grid usage agreement. When these are met and the EP Status is issued, the eligible producer may start engaging in market activities and collecting the FiT price for the power generated according to the FiT PPA with HROTE[26].
(j) Grid Connection is carried out by TSO or DSO, depending on the installed capacity of the facility. It is preconditioned by the completion of construction works, EEA, conclusion of the grid usage agreement and fulfilment of all obligations from the grid connection agreement

Forthcoming developments

Although RoC has made progress in the last couple of years in using the RES, there is still more potential to be exploited. It should be noted that Croatia is a sunny country with a desirable environment especially for wind and solar powerplants, but there is a lack of political will for certain changes. The last and certainly outdated energy development strategy was implemented in 2009.

In November 2018, the Energy Institute "Hrvoje Požar" published the new energy strategy called "Green Book," which represent a strategy until 2030 with a view to 2050. In one of the scenarios in the Green Book, it was envisaged that the increase in RES as a share of total energy consumption will amount to the required 32% in 2030 (as required by the Directive (EU) 2018/2001). While it was envisaged that the Green Book will be enacted in 2018., the newest anticipations suggest that the draft of the energy strategy will be held for a public hearing at the end of April 2019. On 24 December 2018, the Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action entered into force.

[24] Usage of different renewable energy sources may require less (simple solar) or more (hydro) approvals to be undertaken.
[25] Please see Chapter 3.2 for further explanation on the PEP Status and the FiT PPA.
[26] For more information on the EP Status, please refer to Chapter 3.2 below.

The goals of the new regulation is to (i) to implement strategies and measures which ensure that the objectives of the energy union, in particular the EU's 2030 energy and climate targets, and the long-term EU greenhouse gas emissions commitments are consistent with the Paris agreement, (ii) to stimulate cooperation between Member States, (iii) to promote long-term certainty and predictability for investors, (iv) to reduce administrative burdens, and (v) to ensure consistent reporting by the EU and Member States. Also, according to the new rules laid out in the governance regulation, EU countries are required to develop national long-term strategies by 1 January 2020, and consistency between long-term-strategies and national energy and climate plans has to be ensured.

7.3.3 Renewable energy

Market overview

The Croatian Energy Development Strategy 2009 defines that the RoC has good natural conditions for the usage of RES and sets forth the following goals:

(a) fulfilling obligations from the 2009/28/EZ Directive on the promotion of the use of energy from RES in the amount of 20 per cent of direct gross energy consumption;
(b) securing that 10 per cent of energy consumed in transport comes from RES;
(c) ensuring that the electricity production from RES is at 35 per cent by 2020; and
(d) securing that 20 per cent for the gross direct energy consumption for heating and cooling from RES.

Apart from the Croatian Energy Development Strategy, the National Action Plan as of October 2013 ("NAP") to a certain extent sets out the development strategy differently than has been set out in the Energy Development Strategy 2009. According to the NAP, the goals to be achieved until 2020 are as follows:

(i) 39 per cent of RES in gross direct consumption of electricity;
(ii) 10 per cent of RES in gross direct consumption of energy for transport;
(iii) 19,6 per cent of RES in gross direct consumption for heating and cooling.[27]

The Energy Act as well as the Act on renewable energy sources and high efficiency cogeneration (Official Gazette No. 100/15, 123/16, 131/17, 96/18, 111/18) ("**Act on RES and CHP**"), determines that the usage of RES and CHP to be of interest for the RoC.

The Statute on the Usage of RES/CHP determines the plants and cogenerations which use RES, terms and conditions of their usage, and other matters of importance for using RES/CHP. This statute will remain applicable until the new one is adopted. The Registry for registration of the RES power plant projects (the "**RES Registry**") is kept by the Ministry. The Registry in fact shows the number of RES projects (and their respective capacity expressed in MWs) whose development has been initiated.[28] Nevertheless, the status of the RES Registry shows a great interest for the development of the RES projects in the RoC. Keeping in mind the aforementioned in 2.7, although Croatia meets its goals regarding share of renewables by 2020, there is a significant potential for continued integration of renewables which has not yet been used.

Support schemes

A system of incentives for the production of renewable electricity[29] was developed in 2007, and it has been conducted from 1 July 2007 until 31 December 2015 through the following feed-in-tariff ("**FiT**") systems:

1. The Tariff System for the Production of Electricity from Renewable Energy Sources and Cogeneration (Official Gazette No. 33/07);
2. The Tariff System for the Production of Electricity from Renewable Energy Sources and Cogeneration (Official Gazette No. 63/12, 121/13, 144/13);
3. The Tariff System for the Production of Electricity from Renewable Energy Sources and Cogeneration (Official Gazette No. 133/13, 151/13, 20/14, 107/14, 100/15).

[27] Discussed in Section 3.2 below.
[28] http://oie-aplikacije.mingo.hr/pregledi/.
[29] Renewable electricity is electricity produced from the RES.

On 1 January 2016, a new Act on RES and CHP has come into force and the previous FiT systems became inapplicable, except for those producers which have entered into a power purchase agreement ("**PPA**") with HROTE based on the FiT systems. Namely, there is no more guaranteed feed-in price for the purchase of power for 14 years by the HROTE. Instead of a guaranteed feed-in price, a new premium system has been adopted. This will include public tenders for the market premium and for the purpose of entering into a power purchase agreement with guaranteed purchase price. This will also apply to entering into a market premium agreement and power purchase agreement with guaranteed purchase price, instead of FiT PPA. However, all projects which have signed FiT PPA before 31 December 2015 are covered by the "old" FiT incentive scheme.

The newest amendments to the respective Act were made on 20 December 2018, which intensely changed the Act and upon which the Croatian government has passed new regulations[30]. The Incentives Decree specifies the manner and the conditions for the implementation of new incentive models by awarding the market premium or payment of guaranteed purchase price, determination of maximum reference values, determination of maximum guaranteed purchase prices, determination of incentive quotas, primary energy sources and similar.

This Incentives Decree determines the new rules of procedure from which HROTE will enter into PPAs from RES. Namely, such procedure is conducted through the public tenders for granting market premiums or through entering into an agreement with the guaranteed purchase price based on a decision on the best bidder. It is noteworthy that other prescribed and envisaged bylaws[31] have not been enacted in 2018, hence HROTE was not able to enter into new PPA from the RES.

Furthermore, producers of electricity and other persons which are performing activities regarding electricity production and which have a right to an incentive price in accordance to FiT PPA systems or a right to a guaranteed purchase price based on a PPA are included in the ECO balance group automatically in accordance to the Act on RES and CHP. ECO balancing group is run by HROTE as a separate activity from all other activities of HROTE. It is noteworthy that all producers are members of ECO balancing group regardless of when the PPA was entered into.

One of the biggest changes in the last several years in RES field is on the manner how balancing costs are paid. Previously, the balancing costs were paid in accordance to the FiT systems, while now it is determined by the Act itself. Regardless of whether the producers of energy entered into an agreement based on the FiT system or not, their rights and obligations are also regulated by the Act on RES and CHP. Thus said, the respective Act prescribes that HROTE is obliged to pay for the balancing costs from the funds collected on the basis of the incentive fees and from the monthly commission payable for each and every member of the ECO balancing group which connecting power is above 50 kW. A special regulation determines the amount of such monthly commission on an arbitrary basis.

7.3.4 District heating

Market overview

Energy activities within the heating sector in the RoC are production, supply and distribution of heating energy. While the production and supply of heating energy are undertaken as market activities, distribution is undertaken as public service. All energy entities operating in the district heating sector must obtain a licence for undertaking these activities from HERA

[30] Decree on Incentives to Promote Electricity Production from Renewable Energy Sources and High Efficiency Cogeneration (Official Gazette No. 116/18) ("**Incentives Decree**") and Decree on the Share of the New Electricity Delivered by Eligible Producers that the Electricity Suppliers are Required to Take Over from the Electricity Market Operator (Official Gazette No. 116/18) ("**Share Decree**").
[31] Decree on Quotas to Promote Electricity Production from Renewable Energy Sources and High Efficiency Cogeneration; State Aid Program

and must meet the requirements determined by the Ordinance on Licences for Undertaking of Energy Activities (Official Gazette No. 88/15, 114/15, 66/18).[32]

Data on energy operators undertaking one of the abovementioned activities is provided on HERA's website (www.hera.hr). As at 29 March 2019, 30 energy operators held energy licence for production of heating energy, 9 energy operators for distribution of heating energy, and 25 energy operators for supply of heating energy.

Energy operators which undertake energy activities of production, distribution and supply of heating energy are mostly owned by municipalities or the state; while a few of them are partially in private ownership.

As of 2012, due to the legislative changes, HERA is authorized to enact or approve prices, tariff systems and fees according to methodologies for production and distribution of heating energy. HERA adopted Methodology on Determination of Tariff Items for Production of Heating Energy (Official Gazette No. 56/14) and Methodology on Determination of Tariff Items for Distribution of Heating Energy (Official Gazette No. 56/14), which are used as basis for the adoption of decisions on the amounts of tariff items for distribution or production of heating energy with respect to the existing central heating systems.

Regulatory overview

The heating energy sector in the RoC was harmonised with the Third Energy Package, by way of adoption of the Heating Energy Market Act (Official Gazette No. 80/2013, 14/2014, 102/2014, 95/2015, 76/2018) and respective by-laws.

Heating Energy Market Act was used for the implementation of the following directives:

(a) Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.;
(b) Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings; and
(c) Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency.

The main legal act regulating heating energy market is the Heating Energy Market Act acting as an umbrella law for the heating energy sector in Croatia. It defines the conditions for the performance of production, distribution and supply of heating energy.

Legislative and regulatory framework of the heating energy market is comprised of the following legal acts:

- Energy Act (Official Gazette No. 120/12, 14/14, 95/15, 102/15, 68/18);
- Heating Energy Market Act (Official Gazette No. 80/2013, 14/14, 102/14, 95/15, 76/18);
- Act on Regulation of Energy Activities (Official Gazette No. 120/12, 68/18);
- Ordinance on Licences for Undertaking of Energy Activities and Registry for the Provided and Revoked Licences (Official Gazette No. 88/15, 114/15, 66/18);
- Ordinance on the Method of Allocating and Calculating the Costs of Supplied Heating Energy (Official Gazette No. 99/14, 27/15, 124/15);
- Methodology for Determination of Tariff Items for Production of Heating Energy (Official Gazette No. 56/14);
- Methodology for Determination of Tariff Items for Distribution of Heating Energy (Official Gazette No. 56/14);
- Methodology for Establishing the Fee for Connection to the Heating Distribution Network and for Increase in the Connection Capacity (Official Gazette No. 42/16);
- General Conditions for Supply of Heating Energy (Official Gazette No. 35/14);

[32] Certain exception with respect to the production of heating energy exists and relates to those production facilities whose capacity does not exceed 2 MW. This is also discussed in Section 4.3 below.

• General Conditions for Delivery of Heating Energy (Official Gazette No. 35/14, 129/15);
• Grid Rules for Distribution of Heating Energy (Official Gazette No. 35/14).

According to the Energy Act, all energy entities must meet the following requirements:

(i) to be registered for undertaking the respective energy activity with the court registry of the respective commercial court;
(ii) to have sufficient technical qualifications for undertaking the subject activity; [33]
(iii) to prove employment of sufficient number of employees professionally qualified for undertaking of the subject activity;
(iv) to hold sufficient financial means necessary for undertaking of the subject activity or a proof of its capability to obtain one;
(v) that no energy licence for undertaking of the subject energy activity has been taken away from the entity in the last five years prior to the submission of the request;
(vi) to provide a statement that the members of the management board or other responsible persons within the entity have not been convicted of a crime in an economic sector in the last five years.

The entity is also obliged to pay the fee for the issuance of the energy licence determined by the Decision on the Amount of the Fees for Undertaking Works of Regulation of Energy Activities (Official Gazette No. 155/2008, 50/2009, 103/2009, 21/2012). The fees are as follows: HRK 20,000 (approx. EUR 2,691.79) for the production of heating energy; HRK 15,000 (approx. EUR 2,018.84) for distribution of heating energy; HRK 10,000 (approx. EUR 1,345.89) for heating energy supply. Energy operators are also obliged to pay a fee to HERA for its work related to the regulation of energy market. The fee equals to the amount of 0,05 per cent of the total annual profit made out of sale of goods and services while undertaking respective registered energy activity in the preceding year.

Please note that the applicable Croatian energy legislation does not set forth specific legal rules on the minimum share capital or share transfer restrictions different from the general corporate rules regulating the same issues.

The issued energy license determines the period of its validity which can be extended if an application is made three months prior to its expiry. HERA is entitled to revoke the energy licence on a temporary basis if the energy operator no longer fulfils the conditions of technical qualifications and competencies, financial or any other conditions pursuant to which the licence to perform energy activities had been issued. Transfer of energy license is regulated under the Ordinance on Licences for Undertaking of Energy Activities and Registry for the Provided and Revoked Licences. The aforementioned Ordinance stipulates the possibility of the transfer of the energy license only in cases of spin off of an energy license holder, or its merger to or with another legal entity. In the event of spin off and merger, the transfer of energy license is possible to only one legal entity which is the universal successor of the energy license holder in question, subject to the filing of the request for such transfer to HERA within the timelines specified in the subject Ordinance.

Finally, the Heating Energy Market Act recognized the buyer of energy who is different from the end consumer and the supplier. The buyer is a legal or natural person who, in the name and on behalf of the owners and/or co-owners of a building which comprises of more than one individual usable units, buys (i) fuel for production of heating energy in the self-supported heating system (Cro. *samostalni toplinski sustav*); or (ii) heating energy from the supplier of heating energy in a closed (Cro. *zatvoreni toplinski sustav*) or central (Cro. *centralni toplinski sustav*) heating systems. Each such legal or natural person must be registered with the registry of buyers of heating energy kept by HERA.

[33] Specific technical qualifications are set forth for each type of energy activity with the Statute on licences for undertaking of energy activities and registry for the provided and revoked licences. This applies to the human resources and financial obligations requirements also.

Generation

According to the Heating Energy Market Act, a heating energy producer is a legal or natural person which has obtained from HERA a license for performing energy activity of heating energy production. However, the afore mentioned license is only required for production of heating energy by the use of the boilers heating system whose installed capacity exceeds 2 MW.

Although it has been stated previously, and the Heating Energy Market Act states that the production of heating energy is undertaken as a market activity, other provisions from the same act and General Conditions on Supply of Heating Energy in fact recognize further regulation of the heating energy production price. According to the law, the production of heating energy will be considered as public service and not as market activity as long as the quantity of the heating energy produced by one producer exceeds 60 per cent of the needs of a specific district (central) heating system[34]. Under such conditions, the production price is regulated and not negotiated, i.e., the price is determined by HERA based on the methodology prepared also by HERA. The rule on regulated price applies in relation to the heating energy produced within the co-generation; however, such regulated price will be a bit lower than the price not produced from co-generation.

General Conditions for Supply of Heating Energy recognizes several types of agreements which are concluded in the heating energy sector, some of which are those concluded by the producer – agreement on usage of distribution network (between producer and distributor), and agreement on sale of heating energy (between producer and supplier).

Amendment to the Heating Energy Market Act from 2018 prescribed that the producer of the heating energy in closed and central heating systems, as well as the buyer in in the self-supported heating system, have the right to procure gas from suppliers which are public service providers in order to produce heating energy for households, if they are considered as small or medium enterprises and are connected to the gas distribution system. This option will be available until 31 March 2021. The suppliers are obliged to supply the gas in amounts necessary for production of heating energy for buyers in the category of households.

Distribution

Municipalities which have distribution networks on their respective territories are obliged to secure a permanent distribution of heating energy. The right to perform heating energy distribution is acquired pursuant to a concession right to distribute heat energy or a concession to build energy facilities for heat energy distribution, and the licence for distribution of heat energy. The Concession Act and Heating Energy Market Act stipulate criteria according to which the selection of the concessioner for the distribution of heat energy is based. The concessionaire is obliged to pay a concession fee in the amount and manner stipulated by the concession agreement.

The financial amount of the concession fee is determined as a variable amount of the concessionaire's income from heating energy distribution in the previous year regarding the distribution territory for which the concession has been granted. The Government of RoC determines the minimum initial amount, and manner of the concession fee payment. The concession fee is the income of the municipality. Unfortunately, a large proportion of production capacities and heat distribution networks are technologically outdated and energetically inefficient. Losses in heat energy distribution are therefore high, with average losses according to the 2016 HERA Annual Report amounting to 20 per cent.

[34] A central (district) heating system is a heating system which is comprised of more than one building in which heating energy production and supply may be undertaken by one or more energy operators, and in which the distribution of heating energy is undertaken by one energy operator, based on the concession agreement for distribution of heating energy or concession agreement for construction of distribution network.

An energy operator performs heating energy distribution by using its own energy facilities for heating energy distribution or energy facilities used pursuant to an agreement executed with the facility owner.

7.3.5 Natural gas

Market overview

Gas Market Act (Official Gazette No.18/18 of 23 February 2018) ("**Gas Market Act**") recognizes nine types of energy activities within (natural) gas sector – gas production, transport of gas, gas storage, LNG terminal management, distribution of gas, organisation of gas market, gas trading, and gas supply. Only those energy operators which hold energy licence are entitled to undertake the mentioned energy activities.

As at 01 April 20193[35] the following market participants were registered as holders of energy licenses for undertaking specific energy activities in the RoC[36], namely for:

- natural gas production - INA d.d.;
- storage of natural gas - Podzemno skladište plina d.o.o., a company in 100 per cent ownership of Plinacro d.o.o.;
- transport of natural gas - Plinacro d.o.o., a state-owned company;
- distribution of gas - 35 companies;
- management of LNG terminal - LNG HRVATSKA d.o.o., a company owned by HEP d.d. and Plinacro d.o.o.;
- gas supply - 54 companies;
- gas trading – 12 companies;
- organisation of gas market - HROTE;
- management of the location for the supply of LNG and/or CNG: 0.

Regulatory overview

Gas Market Act (Official Gazette No. 28/2013, 14/2014, 16/2017 of 22 February 2017) was firstly enacted in 2013 for the purpose of further liberalisation of the gas market and its harmonization with the Third Energy Package, in particular, Directive 2009/73/EC of the European Parliament and the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L 211, 14.8.2009) ("**Gas Directive**").

In 2018 new Gas Market Act was enacted due to the fact that the obligations imposed by the old Gas Market Act were not entirely in compliance with the Gas Directive. The key changes refer to transparent regulation of rules and procedures for providing energy activities in the gas sector and to enabling all participants to have transparent rules of market participation. The protection of households as end-customers is also one of main ideas of the newly enacted act. Moreover, the new act was enacted for setting the conditions for constructing the private LNG terminal on the island of Krk.

Such LNG terminal is determined as one of the projects of common interest proclaimed by the European Commission. In order to respect such obligation imposed by the EU, RoC had to update and change its gas market legislation in order to realize the fulfil the European energy goals.

Gas energy activities are regulated under the following acts:

- Energy Act;
- Act on Regulation of Energy Activities (Official Gazette No. 120/12, 68/2018 of 27 July 2018);
- Liquified Natural Gas Act (Official Gazette No. 57/18 of 27 July 2018);
- Statute on licences for undertaking of energy activities and registry for the provided and revoked licences (Official Gazette No. 114/2015, 66/2018 of 20 July 2018);
- Gas Market Act;
- Act on Exploration and Exploitation of Hydrocarbons (Official Gazette No. 52/2018 of 6 June 2018);
- Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005;

[35] Information is available on the HERA's website – www.hera.hr.
[36] Wherever the subject energy activity is undertaken by more than three energy operators, only the number and not the names of such operators are given.

- Regulation (EU) No 1227/2011 of the European Parliament and of The Council of 25 October 2011 on wholesale energy market integrity and transparency;
- Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010;
- Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators.

The gas market topic is also regulated by the set of methodologies and other decisions regarding the setting of the amounts of tariff items related to undertaking of regulated gas market activities[37]. What is more, HERA regularly publishes publications with regard to relevant matters on the gas market (e.g. Decision on the average hourly prices for non-standard gas service providers for the second regulatory period 2017-2021).

Overall, the Gas Market Act regulates: (i) rules and measures for secure and reliable undertaking of gas market energy activities; (ii) protection of buyers; (iii) third party access; and (iv) open market access, cross-border gas transport, etc.

Regulated natural gas market activities

The Energy Act defines public service as *service available to end consumers and energy subjects at any time for regulated price and/or conditions of access and usage of energy services, which must be available, sufficient and sustainable in terms of security, regularity and quality of service, and environment protection, energy efficiency usage and climate protection, conducted according to the principles of transparency and impartiality, which is undertaken under the supervision of competent authorities.*

Some of the previously mentioned gas market activities are within the Gas Market Act defined as regulated activities, i.e., activities undertaken as public services.

[37] - General Rules for Gas Supply (Official Gazette No. 50/2018 as of 1 June 2018);
- Network Rules for the Gas Distribution System (Official Gazette No. 50/18 of 1 June 2018);
- Rules for Gas Market Organization (Official Gazette No. 50/2018 as of 1 June 2018);
- Grid Rules of Transport System (Official Gazette No. 50/2018, 31/2019 as of 27 March 2019);
- Grid Rules for Distribution System (Official Gazette No. 74/2018 of 17 August 2018);
- Rules on Usage of Gas Storage System (Official Gazette No.50/18 of 1 June 2018);
- Methodology for Determining the Amount of Tariff Items for the Public Gas Supply Service and the Guaranteed Supply (Official Gazette No. 34/2018 of 11 April 2018);
- Decision for Amount of Tariff Items for Public Gas Supply for the Term from 1 April to 31 December 2019. and for the Term from 1 January to 31 March 2020 (Official Gazette No. 15/2019 of 13 April 2019);
- Methodology for Determination of the Amount of Tariff Items for the Gas Distribution (Official Gazette No. 48/2018 of 25 May 2018);
- Decision on the Amount of Tariff Items for the Gas Distribution (Official Gazette No. 127/2017, 48/2018 of 25 May 2018);
- Methodology for Determination of the Amount of Tariff Items for the Gas Transport (Official Gazette No. 48/2018, 58/2018 of 30 June 2018);
- Decision on the Amount of Tariff Items for the Gas Transport (Official Gazette No. 111/2018 of 12 December 2018);
- Decision on the Indicative Amount of Tariff Items for Gas Transportation (Official Gazette No. 56/2018 of 20 June 2018);
- Methodology for Determination of the Amount of Tariff Items for the Gas Storage (Official Gazette No. 48/2018 of 25 May 2018);
- Decision on the Amount of Tariff Items for the Gas Storage (Official Gazette No. 122/2016, 48/2018 of 25 May 2015);
- Methodology for Determination of the Amount of Tariff Items for the Reception and Dispatch of Liquified Natural Gas (Official Gazette No. 48/2018 of 25 May 2018);
- Decision on the Indicative Amount of Tariff Items for the Reception and Dispatch of Liquified Natural Gas (Official Gazette No. 56/2018 of 20 June 2018);
- Methodology for the Determination of the Fee for Connection to the Gas Distribution or Transport System and for Increasing the Connection Capacity (Official Gazette No. 48/2018 of 25 May 2018);
- Decision on the Determination of the Fee for Connection to the Gas Distribution or Transport System and for Increasing the Connection Capacity for the Term 2017-2021 (Official Gazette No. 122/2016 of 28 December 2016);
- Methodology for the Determination of the Non-Standard Price for the Gas Transport, Gas Distribution, Gas Storage, Reception and Dispatch of the Liquified Natural Gas and for Public Service of Gas Supply (Official Gazette No. 48/2018, 25/2019 of 13 March 2019);
- Decision on the Fee for Gas Market Organisation (Official Gazette No. 23/2016 of 13 March 2016);
- Regulation on Amount and method of payment of Concession Fees for Gas Distribution and Concession for Construction of Distribution System (Official Gazette No. 31/14, 18/2018 of 23 February 2018);
- Regulation on Criteria for Acquisition of a Protected Customer's Status Under the Conditions of a Gas Supply Crisis (Official Gazette No. 65/2015 of 12 June 2015);
- Decision on Adoption of the Intervention Plan on the Protection of Gas Supply Security of the Republic of Croatia (Official Gazette No. 78/2014 of 27 June 2014);
- Criteria for Issuing Approval for the Construction and Operation of a Direct Gas Pipeline (Official Gazette No. 78/2017, 18/2018 of 23 February 2018);
- Rules of operation of liquified natural gas (Official Gazette No. 60/18 of 6 July 2018).

These are as follows: (i) natural gas production; (ii) transport of gas; (iii) gas storage; (iv) management of LNG terminal; (v) distribution of gas; (vi) organisation of gas market; (vii) gas trade; (viii) supply of gas as public service and guaranteed gas supply[38] and (ix) management of LNG/CNG location.

However, storage of gas can be undertaken as market activity if an approval for undertaking gas storage as market activity has been obtained from HERA. Criteria for the issuance of such approval are determined pursuant to the level of market competition related to energy activity of gas storage in the RoC.

Energy operators which undertake regulated gas market activities are (among other things) obligated to secure the application of determined amount of tariff items for transport, distribution and storage of gas, and management of LNG terminal, all in accordance with the regulated conditions. Also, HERA for the purpose of determination of the tariff items (for e.g., storage, distribution) adopts methodologies for their calculation.

Material provisions of the natural gas market law and licensing regulations

Statute on Licences regulates requirements which any energy operator undertaking energy activity is obligated to meet. These requirements are specific to the type of energy activity. According to the Energy Act, all energy entities must meet the following requirements:

(a) be registered for undertaking the respective energy activity with the court registry of the respective commercial court;
(b) have sufficient technical qualifications for undertaking the subject activity; [39]
(c) prove employment of sufficient number of employees professionally qualified for undertaking of the subject activity;
(d) hold sufficient financial means necessary for undertaking of the subject activity or a proof of its capability to obtain one; [40]
(e) not to have any energy license for undertaking of the subject energy activity revoked from the entity in five years preceding the submission of the request;
(f) provide a statement that the members of the management board or other responsible persons within the entity have not been convicted of a crime in an economic sector in the last five years.

The entity is also obligated to pay a fee for the issuance of the energy license determined by the Decision on the Amount of the Fees for Undertaking Works of Regulation of Energy Activities.

The issued energy license determines the period of its validity which can be extended if an application is made three months prior to its expiry. HERA is entitled to revoke the energy license on a temporary basis if the energy operator no longer fulfils the conditions of technical qualifications and competencies, financial or any other conditions pursuant to which the license to perform energy activities had been issued.

Transfer of energy license is regulated under the Statute on licences for undertaking energy activities and registry of issued and revoked licences.

The subject statute stipulates the possibility of the transfer of the energy license only in cases of spin-off of an energy license holder, or its merger to or with another legal entity. In the event of spin-off and merger, the transfer of energy license is possible only to one legal entity which is the universal successor of the energy license holder in question, subject to the filing of the request for such transfer to CERA within the timelines specified in the subject statute.

[38] These types of gas supply are discussed in Section 5.7 below.
[39] Specific technical qualifications are set forth for each type of energy activity with the Statute on licences for undertaking of energy activities and registry for the provided and revoked licences. This applies to the human resources and financial obligations requirements also.
[40] An energy licence holder needs to have sufficient financial means as determined by law, or at least a proof that it is able to obtain them: HRK 50,000 (EUR 6,578.94) for production, storage, distribution of gas, managing of an LNG terminal, and gas market organization, HRK 100,000 (EUR 13,157.89) for production of natural gas and gas transportation, HRK 30,000 (EUR 3,947.36) for supply, HRK 20,000 (EUR 2,631.57) for trade of gas.

Exploration and production

According to the Gas Market Act, the producer of natural gas is entitled to: (i) connect to the transmission and distribution network in line with the Rules for the Gas Market Organisation, Grid Rules of the Transport System and the respective methodology; (ii) contract the sale of natural gas with a supplier of gas in public service, with a guaranteed gas supplier, with a market gas supplier and gas trader; and (iii) access the gas storage according to the conditions set out in the Gas Market Act as well as (iv) to stop or to limit the gas supply if human health, life or assets are directly endangered and for removal of such danger and (v) to decline the production pipeline network access due to the reasons set by the Gas Market Act. The producer of natural gas is (among other things) obligated to secure that the total produced quantity of natural gas is offered to the supplier on the wholesale market and the guaranteed supplier on the territory of RoC first.

Transmission and access to the system

The transmission of gas takes place within the gas transmission and distribution systems. The usage, technical requirements, managing, development, and connection with other parts of gas system are regulated in the Grid Rules for the Transport System and in the Grid Rules for the Distribution System. The transmission system operator provides to the user of the transmission system the delivery and takeover of gas within the limits of the reserved capacity defined for each particular entrance into and exit from the transmission system. With respect to the regulatory aspect of the transmission and access to the system no other change has been noted.

Trading and supply

The Gas Market Act recognizes four types of players within the gas supply sector, i.e., (i) Supplier on wholesale gas market (*opskrbljivač na veleprodajnom tržištu*) (the "**Wholesale Supplier**") (activity previously undertaken by the shipper of gas – *dobavljač plina*); (ii) Supplier in public service (*opskrbljivač u obvezi javne usluge*) (the "**Public Service Supplier**"); (iii) Guaranteed gas supplier (zajamčeni opskrbljivač); and (iv) Supplier of gas to end consumers (different from the supplier in public services and from the guaranteed supplier).

The Wholesale Supplier, under regulated conditions, buys gas from the natural gas producer on the territory of RoC, and sells it, under regulated conditions, to the Public Services Supplier for the supply of households. It is obliged to secure reliable and safe supply, as well as import of gas. The Government of the RoC appoints the Wholesale Supplier for a maximum period of three years. The current Wholesale Supplier is Hrvatska elektroprivreda d.d., i.e., HEP d.d. which was appointed by HERA on 8 February 2019 for the period until 31 March 2020.

The Public Service Supplier for specific county unit which has already been determined as such on the day when Gas Market Act entered into force, will stay the Public Service Supplier until the end of the "gas day" 31 March 2021.[41] The Public Supplier after the afore mentioned date will be determined by the decision of HERA. HERA has adopted Methodology for Determination of the Amounts of Tariff Items for the Public Service of Supply of Gas and Guaranteed Supply (Official Gazette No. 34/2018).

With respect to the wholesale gas trading, HROTE has based on the Gas Market Act and HERA's Decision on approval from 29 May 2018 adopted Rules on Organisation of Gas Market. The rules regulate the following: (i) procedures and standards for organisation and functioning of gas market in line with balancing groups model; (ii) rules on organizing balancing groups, their responsibility and keeping the registry of balancing groups' leaders and members; (iii) rules related to the trading at the virtual trading point; (iv) trades on the trading platform; (v) contractual relations of the HROTE with the leader of balancing group; (v) calculation of the daily deviations for every balancing group; (vi) calculation of the balancing doings respectively

[41] The end of the gas day (kraj plinskog dana).

trades on the trading platform and activated balancing energy for balancing services and (vii) other rules necessary for organisation and functioning of gas market.

Liquefied natural gas

On 2 July 2009, the Croatian Government approved the Decision on Determination of Interest of the Republic of Croatia for the Construction of LNG Terminal – Krk, for the purpose of planning and construction of the LNG terminal on the Croatian Island of Krk. The Gas Market Act regulates that the operator of the LNG terminal will be private or legal entity holding a licence for undertaking an energy activity of operating with the LNG terminal.

In Official Gazette No. 60/18 of 27 July 2018, the Terminal for Liquified Natural Gas Act was launched and caused great discussions and disputes in (para) political public.

The Act determines the interest of RoC in the terminal, regulates the subsidiary application of regulations, the infrastructure of the LNG Terminal ("LNG"), which is of strategic interest to RoC, concession granting procedure on the maritime domain for the realization of terminals and supporting infrastructure, verified real estate, rules and measures necessary in order to preserve the steadiness of natural gas supply and the confidentiality of the data. The Act also determines the investor, that is, the project manager of the project on the island of Krk - LNG Croatia ltd. Pursuant to the Gas Market Act, the Ordinance on Liquefied Natural Gas (Official Gazette 60/18 of 6 July 2018) was issued. The device describes the termination for liquefied natural gas, its development, construction, maintenance and management, contractual relations and terms of use, reservation and use of the terminal, measurement and distribution rules, data disclosure and exchange of information regarding terminal in an open procedure. The expected start of Terminal operation for 2020/2021 was also defined.

According to the most recent available data (April 2018) the Krk Island terminal will include three main elements: LNG storage tanks and vaporization units on a permanently moored floating storage regasification unit, the jetting consisting of a berth and mooring facilities, gas connecting pipelines and other gas infrastructure. The Government of the RoC decided to proclaim the LNG terminal to be strategic project, a decision which was further expanded in 2018 (Strategic Investment Project Act, Official Gazette no. 29/2018, 114/2018 of 19 December 2018). The aforementioned Government's decision identifies two phases of construction – floating terminal and land terminal. However, there is still no information on capacity timelines, or the scope of the activities (budget). The project does not have the support of the local community, which was clear during the public consultation on the environmental Impact Study and demonstrations held in March 2018.

7.3.6 Upstream and the oil market

Market overview

Oil mining and construction of oil mining facilities are activities of interest to the RoC. The activities of exploration and production (exploitation) of oil in Croatia are undertaken by INA d.d., the only company which holds a license for oil production in the RoC and is owned by the Hungarian company MOL (49.1 per cent), the RoC (44.8 per cent), while the other 6.1 per cent is owned by other private or institutional stock holders.

Regulatory overview

The main acts and by-laws regulating oil activities in the RoC are:
- Oil and Oil Derivatives Market Act (Official Gazette No. 19/14, 73/17);
- Mining Act (Official Gazette No. 56/13, 14/14);
- Act on Exploration and Exploitation of Hydrocarbons (Official Gazette No. 52/18);
- Regulation on Fee for Exploration and Exploitation of Hydrocarbons (Official Gazette No. 37/14, 72/14, 52/18);
- Act on Establishment of Agency for Hydrocarbons (Official Gazette No. 14/2014, 73/17);

- Regulation on Content and Manner of Preparation of Mining-Geology Studies (Official Gazette No. 142/13, 52/18);
- Regulation on Construction of Oil-Mining Objects and Facilities (Official Gazette No. 95/18);
- Regulation on Data that Energy Entities are Obliged to Submit to the Ministry (Official Gazette No. 132/14, 16/15);
- Regulation on the Calculation of Average Daily Net Import, Entry, Average Daily Consumption and Quantity of Oil and Oil Derivates Stocks (Official Gazette No. 43/16);
- Intervention Plan in the Event of an Extraordinary Imbalance in Market Supply of Oil and Oil Derivates (Official Gazette No. 111/12, 19/14);
- Insurance Plan, Dynamics of Formation and Settlement of Compulsory Stocks of Oil and Oil Derivates, Storage Organisation and Regional Distribution (Official Gazette No. 149/09);
- Act on Basics of Transport Safety for Oil Pipelines and Gas Pipelines (Official Gazette No. 53/91).

Exploration and exploitation of hydrocarbons is primarily regulated by the Act on Exploration and Exploitation of Hydrocarbons (Official Gazette No. 52/18, hereinafter: "**Hydrocarbons Act**"). Its provisions refer to exploration and exploitation of the hydrocarbons located in the ground or subsoil of internal waters of the territorial sea of the RoC or under the ground of the continental shelf of the Adriatic Sea coast, all the way to the demarcation line with neighbouring countries, to which, pursuant to international law, the RoC exercises jurisdiction and sovereign rights. It governs the management, exploration and exploitation of hydrocarbons, issue of a licence for the exploration and conclusion of an agreement on the exploitation, the fee, inspection, misdemeanour provisions and other issues.

Hydrocarbons Act contains provisions which have been harmonized with the following documents of the European Union:

- Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons, (OJ L 164, 30.6.1994);
- Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC (OJ L 178, 28.6.2013); and
- Directive 2009/31/EC of the European Parliament and of the Council on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and of the Council Directives 2006/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006 (OJ L 140, 5.6.2009).

Issues pertaining to specification of hydrocarbon reserves, specification of exploitation fields, the registry of exploration areas and/or exploitation fields, preparation and verification of mining projects, construction and utilization of mining facilities and plants, preparation of mining plans and performance of mining surveys, site rehabilitation, damage compensation, safety and protection measures, qualifications and skills needed for conducting particular mining works and other issues which have not been regulated by the Hydrocarbons Act and regulations to be adopted based on this Hydrocarbons Act, shall be appropriately subject to the provisions of the Mining Act and regulations that have been adopted based on the Mining Act.

Hydrocarbons Act contains provisions which have been harmonized with the following documents of the European Union:

- Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorizations for the prospection, exploration and production of hydrocarbons, (OJ L 164, 30.6.1994);
- Directive 2013/30/EU of the European Parliament and of the Council of 12 June 2013 on safety of offshore oil and gas operations and amending Directive 2004/35/EC (OJ L 178, 28.6.2013); and
- Directive 2009/31/EC of the European

Parliament and of the Council on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and of the Council Directives 2006/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006 (OJ L 140, 5.6.2009).

Furthermore, Oil and Oil Derivatives Market Act regulates the rules and measures for safe and reliable production of oil derivatives, transport of oil and oil derivatives, wholesale and retail of oil derivatives, storage of oil and oil derivatives as well as the market access, intervention plan in the event of an extraordinary disturbance in the supply of oil and oil derivatives markets, as well as operational and compulsory stocks of oil and oil products. It implemented the Council Directive 2009/119/EC of 14 September 2009 imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products (OJ L 265, 9.10.2009).

Institutional overview

The main state bodies which are each within their competency involved or planning to be involved in undertaking of hydrocarbons exploration and exploitation activities are the Government of the RoC, competent ministries, particularly the Ministry, and the Hydrocarbon Agency.

The Ministry is in charge of (i) preparation and organisation of presentations aimed at introduction of potential investors with the hydrocarbon potentials of certain regions of the RoC; (ii) implementation of the unique procedure for licence issue and agreement conclusion; and (iii) preparation of regulations with respect to the exploration and exploitation of hydrocarbons.

The Hydrocarbon Agency has been established by way of the adoption of the Act on Establishment of Agency for Hydrocarbons. Among other duties and obligations, CHAis in charge of operative support to the competent bodies, especially by (i) participation in the preparation and organisation of presentations and updating, leading and organising the geological and geophysical data room, and data rooms on drillholes, aimed at introduction of potential investors with the hydrocarbon and geothermal potentials of certain regions of the RoC; (ii) making proposals to the Ministry for rendering a decision on implementation of a public tender procedure for exploration and exploitation of hydrocarbons for the selection of the best bidder for the licence issue and agreement conclusion and participation in the implementation of such public tendering; (iii) specification of the costs of the hydrocarbon exploration and exploitation and obtaining technical documentation for the exploration and exploitation field; (iv) providing conditions for efficient exercise of the rights and liabilities of the investor pursuant to issued licences and concluded agreements; (v) following trends and international in hydrocarbon exploration and exploitation; (vi) monitoring and controlling the investor in the performance of all the obligations assumed according the licence and the agreement and informing the competent authorities about observed irregularities; (vii) operational monitoring of the payment of the agreed fees and costs for the purpose of recovering costs, which is one of the input parameters when calculating part of the compensation when it comes to hydrocarbon division; (viii) preparation of reports on the fulfilment of the investor's commitments pursuant to issued licences and concluded agreements; (ix) providing assistance to the investor and coordination between the investor and competent state bodies in relation to fulfilment of the commitments under the issued licenses and concluded agreements; and (x) providing assistance to the investor for obtaining all the necessary documents and/ or documents required for the exploration and exploitation of hydrocarbons, and in accordance to the special regulations and the concluded agreement; (xi) providing assistance to the investor for the purpose of resolving the property-legal relations for landfills within the exploration area and/or the exploitation field; (xii) submits reports to the European Commission on all the general difficulties encountered by investors when accessing or conducting activities to of hydrocarbon exploration and/or exploitation activities in third countries to which they are subject to compliance with the business secrets; (xiii) participation in the submission of all reports and notifications to the European Union bodies in accordance with the applicable regulations and the acquis communaitaire; (xiv) keeping a register of agreements containing basic information on all contracts concluded for which CHA has public authority; (xv) controlling the reports that investors are required to submit when disposing of gases in geological structures, taking corrective measures, approving temporary plan of handling after the closure of the underground warehouse, and is responsible for monitoring, reporting and corrective measures after the closure of the underground warehouse; and (xvi) providing administrative and professional support to the Ministry when developing and implementing hydrocarbon exploration and exploitation projects.

The CHA shall cooperate with competent state bodies within the framework of their competences in the implementation of the supervision over the performance of mining works and exploitation, construction and usage of exploitation objects and facilities, all in compliance with the issued licence, concluded agreement, provisions of the Acts and provisions of other special regulations. It shall also be entitled to, at any time as long the licence and agreement are effective and valid, request any data and/or information from the investor with respect to the fulfilment of their commitments in accordance with the conditions stated in the issued licence and provisions of the concluded agreement, provisions of the Acts and other special regulations, and the investor shall submit these data to the CHA.

Material provisions of the upstream oil market law and licensing regulations

Hydrocarbons Act stipulates unified procedure for the issuance of the Licence for the Exploration and Production of Hydrocarbons and conclusion of an Agreement for Commercial Use of Hydrocarbons. The issuance of the license is executed by way of the public tender procedure which begins by Government's decision based on the proposal by the CHA. The award of the License for the Exploration and Production of Hydrocarbons can be carried out within one unified tender procedure or within a separate procedure if the areas in question were already subject to previous tender procedures or in case of relinquished areas.

Regarding the investors suitable to be awarded the Licence for the Exploration and Production of Hydrocarbons, they must comply with statutory requirements as set out in the Hydrocarbons Act. Namely, the investor must be registered for the activities of exploration and exploitation of hydrocarbons and must not be criminally convicted of certain crimes (such as: being a part of a criminal organisation, corruption, fraud, terrorism, money laundering, human trafficking), must pay all due public duties and taxes, cannot be in the process of liquidation or have had ceased their business activities. The Hydrocarbons Act further regulates which requirements are to be taken into consideration in assessment the potential holder's technical and financial capabilities.

Upon being awarded with the License for the Exploration and Production of Hydrocarbons, the investor will enter into an agreement with the Government of Croatia which will regulate all rights and obligations of the contractual parties.[42]

The licence is issued for a maximum period of 30 years and comprises the exploration and exploitation period. The exploration period lasts five years at the most, however, due to justified reasons and following a proposal of the investor, it can be prolonged no more than two times during the exploration period in a way that each of the extensions may last six months at the most.

The Hydrocarbons Act prescribes the possibility that the tender specification

[42] The draft agreement is a part of the necessary tender documentation.

imposes an obligation that the national oil company must participate with the chosen investor in the project in a percentage between 10 and 30 %. In such cases, the national oil company and the chosen investor conclude an agreement on joint investment within three months from the day of the issuance of the Licence for the Exploration and Production of Hydrocarbons, and before the execution of the Agreement on exploration and exploitation.

Hydrocarbons Act recognizes two types of the agreements:

(i) Agreement on exploration and sharing of exploited hydrocarbons (i.e., according to the information provided by the Ministry, this is a production sharing agreement);

(ii) Agreement on exploration and exploitation of hydrocarbons (i.e., this is a standard concession agreement)

The production sharing agreement is executed by the Government and the investor, while the standard concession agreement is executed by the Government and the investor after the obtainment of the abovementioned License, or by the Ministry and the investor, if the investor is already in possession of the valid License.

According to the "Definitions" part of the Hydrocarbons Act, the fee payable by the investor in line with the Hydrocarbons Act and the subject agreement is the fee payable for usage of extracted hydrocarbons and determined by the Government of RoC by way of a regulation.

The Government of RoC has on 19 March 2014 adopted the Regulation on Fee for Exploration and Exploitation of Hydrocarbons, according to which the fee consists of the total monetary fee and the sharing of extracted hydrocarbons between the Roc and the investor. The total monetary fee comprises of six individual fees, while the sharing of the extracted hydrocarbons is determined as a percentage of the quantity of gained hydrocarbons belonging to the RoC.

Oil and Oil Derivatives Market Act (Official Gazette No. 19/14, 73/17) lists the following energy activities related to the oil and oil derivatives market: (i) production of oil derivatives; (ii) transportation of oil (via oil pipelines) and oil derivatives (via oil derivatives pipeline); (iii) transport or oil, oil derivatives and biofuel via road, railway and waterway; (iv) wholesale and retail of oil derivatives; and (v) storage of oil and oil derivatives. The entities undertaking such activities must obtain approvals by HERA, with exception for the activities listed under (iii) and retail sale of oil derivatives.

7.3.7 Impact of the coronavirus pandemic on the energy and infrastructure4[3]

A. Covid-19 Response Investment and Support Initiative – General

The Government of the Republic of Croatia („**RoC**") issued two sets of measures in March and April 2020 intended to stimulate the economy during the Covid-19 pandemic. The first package, which consists of 63 measures to be implemented through 19 legislative acts, was introduced on 17 March 2020 and accepted by the Croatian Parliament on 19 March 2020, with the majority of measures relating to the preservation of liquidity and jobs. The measures were summarized and described by the Government of RoC as three horizontal measures intended to aid the economy through interest-free deferral of public contributions for entrepreneurs affected by the crisis, meaning - no personal income tax, no corporate profit tax and no health and pension insurance contributions. In addition, the next package of measures intended to stimulate the economy was announced on 2 April 2020 and adopted by the Croatian Parliament on 7 April 2020. The second package introduced two new financial instruments - the "Covid-19 Loan" and "Micro Loan for Rural Development", as well as some significant tax measures, while it also expanded the previously accepted measure intended for preservation of jobs.

[43] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

The measures are being implemented by several ministries and national authorities, including the Croatian Employment Service, Ministry of Finance – Tax Administration, Croatian Bank for Reconstruction and Development – "HBOR", and Croatian Agency for SMEs, Innovations and Investments – "HAMAG BICRO".

Depending on the specific measure, a range of sectors is covered by the newly introduced initiatives, including agriculture (livestock production and processing; dairy farming and processing; crop production, storage and processing; growing of fruit and vegetables, as well as storage and processing into semi-durable goods; fisheries and aquaculture), textiles, clothing, footwear, leather and wood manufacturing, forestry, postal services, road and maritime transportation and storage, culture and creative industries, accommodation and food services, tourism, as well as health tourism.

Organisations covered by the Government's initiative vary, depending on the measure in question. For example, with regard to the measures intended for the preservation of jobs implemented by the Croatian Employment Service, the primary subjects are employers – entrepreneurs, which includes companies regardless of their size, as well as natural persons as crafts and self-employed persons. Furthermore, the new financial instrument the Micro Loan for Rural Development is provided only for the micro- and small-sized enterprises, whereas the Covid-19 Loan is provided for the micro-, small- and medium-sized enterprises.

Types of support available under the initiative differ depending on the measure, ranging from financing through subventions to deferral of payment, or even complete write-off of taxes and contributions for the following months.

Job retention measures

Subventions are available for support of job retention in industries affected by Covid-19, whereby employers affected by the coronavirus, i.e. those who are either not performing their activities due to the decision of the Civil Protection Headquarters or experiencing difficulties in doing business due to special circumstances, may request subventions in the amount of HRK 3,250 (approximately EUR 430) per full-time employee (or a proportional amount for a part-time employee) per month for March, increasing to HRK 4,000 (approximately EUR 530) for April and May. These measures are available from 1 March 2020 and are currently intended to last up to three months. Furthermore, all beneficiaries of self-employment support, as well as employers who have registered and made application to the Croatian Pension Insurance Institute by the end of February 2020, may request assistance via payment of contributions (the so-called second pillar pension). Moreover, taxpayers eligible to receive support for job retention as salary subvention are also exempt from paying public contributions to the amount of co-financed net salary.

Companies not eligible for measures regarding the support of job retention are those founded by the RoC or regional and local municipalities, as well as companies in which the RoC or municipalities hold 25% of shares or more (with the exception of employers from the manufacturing industry and accommodation and food services). Also, employers already benefiting from other measures regarding justified expenses as salary expenses (Croatian Employment Service's measures or EU measures) cannot simultaneously use the new measures but may request a standstill period for the previously used measures. Employers that experienced a decline in staff from 1 March to 20 March 2020 may be granted support. However, the support will be lost if, in the period from 20 March until the payment of subvention, the employer experiences a loss of 40% of employees (if there are less than 10 employees), or 20% for small businesses, 15% for medium-sized enterprises and 10% for large companies (excluding expiration of fixed-term work contracts, retirement, and termination of contract due to employee misconduct). There are three defined deadlines with regard to subventions for salary expenses – requests received by 7 April 2020 will be approved for salaries for March, April and May 2020, requests received from 8 April until 7 May will be approved for salaries for April and May 2020, while requests received from 8 May until 7 June will be approved for salaries for May 2020. It has been reported that the subventions for the salary expenses for March were paid by the Croatian Employment Service in a timely manner.

Tax and financial measures

With regard to the several measures intended to be implemented by the Tax Authority, according to the Croatian Chamber of Economy, one of the most welcomed is the deferral of payment of corporate income tax, personal income tax and social security contributions. It is announced to be available to companies having a 20% - 50% decline in revenue, with the possibility to make interest-free instalment payments up to 24 months. Also, a complete write-off of taxes and contributions in the next three months will be available to small and medium-sized companies with annual revenues of up to HRK 7.5 million (approximately EUR 1 million) with a decline in revenues of more than 50%. For large companies (with annual revenues above HRK 7.5 million) with a decline in revenues of more than 50%, tax exemption will be available - in proportion to the decline in revenue over the next three months. All companies regardless of annual revenue are allowed to pay VAT after collection of the invoice, as opposed to after issuing the invoice. Finally, the deadline for submission of the annual financial statements for 2019 is postponed to 30 June 2020.

As mentioned above, new financial instruments are available for the purpose of financing current business operations and for the settlement of short-term liabilities towards the state and other short-term liabilities for entrepreneurs experiencing Covid-19 consequences. For example, a loan in the minimal amount of HRK 100,000 may be available with an interest rate of 2.00% per annum, fixed for HBOR part of the loan in the risk-sharing model and with the possibility to reduce the interest rate.

The business might also benefit from the moratorium on credit obligations offered by HBOR and commercial banks for the period of at least the next three months, subject to conditions of each bank.
Forms are available online on the websites of the relevant national authorities, with instructions regarding all additional documentation which is necessary for duly submission. Official weblinks to information on the abovementioned initiatives are available in Croatian:

- https://koronavirus.hr/vladine-mjere/101;
- https://hamagbicro.hr/financijski-instrumenti/kako-do-zajma/;
- https://www.porezna-uprava.hr/Stranice/COVID_19_informacije.aspx;
- https://mjera-orm.hzz.hr/potpora-ocuvanje-radnih-mjesta/.

B. Impact on the Energy and Infrastructure Sectors

Although the energy and infrastructure sectors have not yet been as severely affected by the Covid-19 pandemic as other industries, and therefore have not been included in the Government's March and April responses in a sector-specific manner, both sectors did register some market changes.

Following the global trend of oil price reduction due to high supply and relatively low demand as one of the Covid-19 pandemic consequences, the prices of oil in the RoC have also been falling in the past six-week period, reportedly reaching a ten-year low at the beginning of April 2020. In addition, following the global wholesale gas price reduction in 2020, the prices of gas have also decreased in RoC, however, up to this moment, the reductions have only applied to households. Furthermore, the HEP group companies, which is the national power company, reportedly temporarily ceased to enforce buyers' due obligations due to Covid-19 pandemic economic consequences, until further notice. It has been speculated that the next set of measures to be announced by the Government of RoC might include an electric energy price reduction for both households and businesses.

Anticipating major consequences on the infrastructure industry following the impact of the Covid-19 pandemic, five professional chambers - including architects' and engineers', suggested that the Government adopts 10 emergency measures intended to help the construction sector. Among those, it is suggested to continue the works on construction sites in accordance with the recommendations of the Civil Protection Headquarters, to establish an emergency import line of supply for important materials (e.g. concrete reinforcing bars and glass) and to encourage the continuation of all planned public procurement procedures.

7.4 CYPRUS

7.4.1 Introduction to the energy market

By virtue of Part II of the Electricity Market Regulation The main objectives of the energy policy of Cyprus are to meet the demand for energy at the lowest possible cost to the consumers and with the lowest possible impact on the environment by enhancing competition in this previously monopolised sector and by promoting the conservation of energy and the use of natural gas and indigenous, renewable energy sources. In line with article 194(1) of the Treaty on Functioning of the EU, Cyprus is focusing on a rapid move to gas and renewable energy sources for its energy needs, with financial assistance from the government being made available for renewable energy projects.[44]

(a) The Energy Service of the Ministry of Energy, Commerce and Industry

The Energy Service of the Ministry of Energy, Commerce and Industry is the governmental authority that oversees and coordinates the Cyprus energy sector, including the preparation of the necessary legislation, policies and programmes that promote energy conservation and renewable energy sources. It also represents the government at EU level in the formation of EU energy policy, monitors the availability of energy capacity to satisfy domestic demand, and maintains and manages the required reserves of petroleum products.

Within the context of promoting Cyprus energy policy the Energy Service has responsibility for the realisation of a series of projects. These have included the establishment of the proposed Energy Centre for the importation, storage and handling of petroleum products and gas including both liquefied natural gas and liquefied petroleum gas, in the Vasilikos area and the EuroAsia interconnector. In so far as renewable energy sources are concerned, the Energy Service is promoting projects for solar energy, wind energy, hydro energy and biomass-derived energy through Law 112(I) 2013.

In addition to the various tasks entrusted to the Energy Service and under section 3 of the Application of European Regulations in the Field of Energy Law 278(I) of 2004, the Energy Service has been nominated as the competent authority for the purpose of implementing the relevant EC regulations which are applicable in Cyprus.

(b) Treaties

Article 194 of the Treaty on the Functioning of the European Union sets out EU policy on energy, which sets the framework for Cyprus's national policies.

In addition, Cyprus is also a party to a number of specific treaties. A bilateral agreement has been concluded for the storage and maintenance of petroleum products in Greece on behalf of Cyprus pursuant to Law 53(III) of 2004. Following the agreement on the delimitation of the Exclusive Economic Zone between Cyprus and Egypt in 2003 and a similar agreement between Cyprus and Lebanon, Cyprus and Egypt signed another agreement in May 2006 on the joint development of hydrocarbon sources straddling the demarcation line which separates the exclusive economic zones of

[44] Neocleous's Introduction to Cyprus law, Andreas Neocleous & Co LLC, Limassol, Cyprus, 2010 Edition

the two countries. Cyprus is discussing similar bilateral arrangements with other neighboring countries.

Cyprus is a member of the International Atomic Energy Agency pursuant to Law 21 of 1965. As a member Cyprus cooperates in promoting nuclear safety and security.

7.4.2 Electricity

Market overview

The Cyprus Energy Regulatory Authority

Law 122(I) of 2003, as amended ("**Electricity Law**") the Cyprus Energy Regulatory Authority ("**CERA"**) was established as an independent governmental authority with extensive powers in the energy field, especially the electricity and gas sectors.

It is the responsibility of CERA to ensure the effective operation of the electricity market in Cyprus and to, *inter alia*, ensure the existence of effective competition and the avoidance of discrimination and protect consumer interests. In addition, CERA has a wide discretionary authority to, *inter alia*, award, inspect, amend or withdraw permits and advise the Minister on electricity matters.

In instances where CERA intends to take a regulatory decision, it must consult with the holders of the relevant licenses and any interested parties and must publish a draft of its decision so that the interested parties are sufficiently notified under section 26(2) of the Electricity Law. With respect to the natural gas market, CERA has further powers under section 15 of the Electricity Law to conduct consultations in relation to any matter that may affect the natural gas market.

The Electricity Authority of Cyprus and the Electricity Market

The Electricity Authority of Cyprus (EAC) was established under the provisions of the Development of Electricity Law, Cap. 171, and until the accession of Cyprus to the EU, it had the monopoly of the generation and supply of electricity throughout the island. The liberalisation of the electricity market began with the enactment of the Electricity Law, which transposed EC Directive 2003/54 into national law. Under section 23(h) of that Directive and section 24(1)(a) of the Electricity Law, CERA must ensure the existence of effective competition in the local electricity market.

From 1 May 2004, CERA achieved the liberalisation of about 35 per cent of the electricity market, whereby 726 of the largest electricity consumers in Cyprus, each consuming at least 350,000 kilowatt-hours annually, have the power to select their electricity provider, as per CERA's Report to the EC in line with the Electricity and gas Directives for the period from July 2005 to July 2006. CERA is currently taking steps to achieve the full liberalisation of the electricity market for all consumers as soon as possible.

At present, EAC remains the dominant producer of electricity in Cyprus and at the same time is the owner of both the electricity transmission system and the electricity distribution system. Cyprus' full liberalization of the electricity market is currently going through a long transition period. CERA, also, published a regulatory decision on the 13th of March 2020, which nominates EAC as the main supplier in the electricity market until the implementation of the new model of purchase of electricity.

Regulated electricity market activities

(a) Licensed Activities

Section 34 of the Electricity Law requires any person interested in engaging in any of the following activities to apply to CERA for the issue of a licence to, *inter alia*, construct an electricity production station or produce electricity and supply electricity to selected or non-selected consumers.

Under section 35 of the Electricity Law, CERA can permit exemptions from the requirement to hold a licence to construct electricity production stations and to supply electricity on such terms and conditions as it may think fit. Exemptions may be permitted for the self-production of electricity up to 1 mw by certain category of persons, for the production of electricity from renewable energy sources up to 5 mw or for the supply of electricity not exceeding 0,5 mw to each station.

(b) Application for a License

Pursuant to section 37 of the Electricity Law, an applicant, who must be an EU citizen, or a company established and managed in the EU, must submit an application in the prescribed form and pay the prescribed fee under the Licenses Regulations, 538 and 467 of 2004, respectively.

Subject to any relevant ministerial circulars on governmental policy, according to section 38 of the Electricity Law, *inter alia*, the following criteria must be taken into consideration objectively and without discrimination by CERA when examining a license application:

- The safety of the electricity system, the production facilities and the electricity cable lines; and
- The protection of the environment.
- Public health and safety
- The applicant's qualifications, including its technical and financial resources.

(c) Electricity Market Operations

Reference has already been made to the derogations granted to the government in respect of the timetable for full liberalisation of the electricity market and the dominance of the EAC in the production of electricity and ownership of the electricity transmission and distribution systems. The local electricity market currently falls within the ambit of Small Isolated Systems as described in EC Directive 2003/54. Having said that, Cyprus has recently agreed to implement the EuroAsia Interconnector with Greece and Israel for the connection of the national electrical systems of each country through sub-marine cables.

(d) Transmission System Operator and Distribution System Operator

The Transmission System Management Unit ("Transmission System Operator" or "TSO") has been established under section 57 of the Electricity Law.

The TSO has a wide range of duties and powers, including, but not limited to:

- Operating a reliable, safe and efficient transmission system and ensuring that the necessary production facilities exist in this respect; and
- Securing the maintenance and development of the transmission system.

The TSO must ensure, on the basis of objective criteria, that proper allocation of the load and use of the transmission system is made under the licenses, the Rules of Transmission and Distribution or the Electricity Market Rules, and that the operation and management of the electricity trade is compatible with the Electricity Market Rules pursuant to sections 61 (f) and (g) of the Electricity Law. The functions of the Distribution System Operator described in articles 24 and 25 of EC Directive 2009/72 have been entrusted to the specialised network business unit of the EAC, so that the EAC is both the owner and the operator of the distribution system. Nevertheless, under sections 73 and 80 of the Electricity Law, the common rules for transmission and distribution and the Electricity Market Rules proposed by the TSO must be approved by CERA.

(e) Electricity Consumer Agreements

Under section 43 of the Electricity Law, those consumers that have the ability to choose their electricity supplier can enter into contracts with the supplier.

(f) Co-Generation

Law 174(I) of 2006 on the promotion of co-generation of electricity and heat was enacted, implementing Directive 2012/27/EU, with the aim of increasing energy efficiency and improving security of supply.

Furthermore, the Council of Ministers announced in August 2018 the "Plan for the production of electricity from electricity and heat cogeneration units of high performance for maximum power consumption of 5 mw". The purpose of the plan is to promote the installation of electricity and heat co-generation units in Cyprus.

7.4.3 Renewable energy

Regulatory overview

The Promotion and Encouragement of Use of Renewable Energy Sources and Energy Savings Law, 112(I)/2013, as amended, constitutes the legal framework on which the effort to move to renewable energy sources is based under the obligations imposed by EC Directive 2009/28.

Section 2 of Law 112(I)/2013, defines the term 'renewable energy sources' as the renewable non-fossil energy sources of wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases.

To encourage the use of renewable energy sources, a special fund with a separate personality has been set up whose purpose, as stipulated in section 9 of the Law 112(I)/2013), to subsidise or finance, *inter alia*, the production or purchase of electrical energy derived from renewable energy sources and installations, equipment and other activities that save energy.

Under section 4 of the Regulation of Energy Efficiency of Buildings Law, 142(I) of 2006, as amended, each new building and every building that it is undergoing a large renovation must comply with the minimum energy efficiency requirements specified by the relevant Ministerial Order. The Law also provides, in sections 6, 7 and 9, for the issue and display of energy efficiency certificates, with the exemption of certain buildings specified in its Schedule pursuant to section 8.

In addition, Cyprus is subject to Directive 2009/125/EC which establishes a framework for the setting of eco-design requirements for energy-using products.

Moreover, through Law 31(I) of 2009 as amended, Cyprus implemented the 2012 Energy Efficiency Directive, which establishes a set of binding measures to help the EU reach its 20% energy efficiency target by 2020. Under the Directive, all EU countries are required to use energy more efficiently at all stages of the energy chain from its production to its final consumption. Hence, to reach the EU's 20% energy efficiency target by 2020, individual EU countries have set their own indicative national energy efficiency targets. Depending on country preferences, these targets can be based on primary or final energy consumption, primary or final energy savings, or energy intensity. In 2018, the Directive (EU) 2018/2002 of the European Parliament and of the Council was adopted to amend the initial efficiency directive (2012/27/EU) by setting an additional energy efficiency target for 2030 of at least 32.5%.

7.4.4 Upstream and the oil market

Regulatory Overview

Under section 4 of the Petroleum Products Law, Cap 272 (the "Petroleum Products Law") as amended, any person who wishes to store and maintain petroleum products must have a permit from the relevant District Officer. Pursuant to section 4(5) of the Petroleum Products Law this requirement does not apply to any petroleum products:

- Not destined for sale and which are stored in such a way that they are safely enclosed in separate containers and their total quantity does not exceed four gallons in cases of Class A petroleum products that must be further contained in dispensers not exceeding one litre, provided that the relevant products do not exceed 100 gallons of Class B petroleum products or 250 gallons of Class C petroleum products;

- Contained in storage dispensers of any aircraft, engine-driven vessel or vehicle whose power is derived from such product; or
- Transported as stock reserve on any vehicle whose power is derived from petroleum products, provided that the stock reserve does not exceed eight gallons.

Additionally, pursuant to section 2 of the Petroleum Products Law, the term 'petroleum products' includes any flammable substance which is produced from oil and it is classified as follows:
- Class A: petroleum products which include liquefied petroleum gas, aircraft fuel, gasoline, car petrol, crude oil and any other petroleum product that ignites at a point lower than 37,8 degrees Celsius; or
- Class B: petroleum products which include kerosene, paraffin oil, gas oil/diesel and any other petroleum product that ignites at a point not lower than 37,8 degrees Celsius and less than 60 degrees Celsius; or
- Class C: petroleum products which includes heating oil, light fuel oil, heavy fuel oil mineral oil fuel and any other petroleum product that ignites at a point not lower than 60 degrees Celsius.

Pursuant to section 9(1) of the Petroleum Products Law, the Council of Ministers may adopt regulations on, *inter alia*, the issue of permits and the management of storage facilities including the specifications of such facilities, the control and regulation of the transport and transmission of petroleum products between facilities on ships and on land and the specifications of the materials and systems to be used for the prevention of fires at any facility for which a storage permit has been granted. Under the Oil Stocks Law, 149(I) of 2003 as amended, a special committee called COSMOS (Cyprus Organization for Storage and Management of Oil Stocks was established to manage the 90-day reserves which Cyprus had an obligation to maintain following its accession to the EU according to EC Directive 68/414.

The Specifications of Petroleum Products and Fuel Law, 148(I) of 2003, requires various oil products to meet certain specific standards. These are set by Ministerial Orders that rely on specifications adopted at EU level under EC Directives 98/70/EC and 99/32/EC. Specifications on health and environmental matters are included in those Directives, as well as lower limits for the sulphur content of heavy fuel oils and gas oil. Pursuant to sections 5-10 of Law 148(I) of 2003, the quality of fuel is supervised by the Energy Service through market surveillance by inspectors, the designation of appropriate testing laboratories, the setting of sampling methods and the collection and analysis of the relevant data.

Pricing

The Petroleum (Establishment of Maximum Retail Pricing in Extraordinary Cases) Law, 115(I) of 2004, provides that the retail price of petroleum products is freely set by the petroleum companies and the petrol station owners.

Minimum taxation rates for motor fuel, heating fuel, electricity and motor fuel used for industrial or commercial purposes are adopted at European level, as per EC Directive 2003/96, as amended.

7.4.5 Natural gas

Market overview

Cyprus is a relative newcomer to the upstream oil and gas industry, but it is a sector which develops rapidly. For some years there had been indications of likely substantial gas deposits in the Levant Basin in the South Eastern Mediterranean area which were confirmed by the discovery of the Tamar gas field in Israel's Exclusive Economic Zone (EEZ) in the early 2000s. Interest soon spread to the water of Cyprus and the government took steps to delineate its EEZ and initiate a first licensing round for prospecting and exploration. Further discoveries were announced in the following years. As a result, successful discoveries, Cyprus is becoming an important energy hub while international oil and gas companies have plans for further exploratory for 2020. It is worth noting that Cyprus has signed an intergovernmental agreement with Egypt for the construction of a subsea natural gas pipeline, which will carry gas from Aphrodite to Egypt. Furthermore, in November 2019, the Republic of Cyprus issued a license for exploitation of hydrocarbons from the Aphrodite field for a period of 25 years.

Additionally, in January 2020, Greece`s Environment and Energy Minister, Cyprus' Energy Minister and Israel' Energy Minister signed an intergovernmental agreement in relation to the proposed construction of the EastMed natural gas pipeline between the three countries. The Government's objective is to make Cyprus not only a hydrocarbon producer but a gas export hub for the region, taking advantage of its location and its geographical stability in a volatile region.

Regulatory overview

As required by EC Directive 2003/55, which was repealed by EC Directive 2009/73, Cyprus passed the Natural Gas Market Regulation Law, 183(I) of 2004, as amended, which constitutes the main legal framework for the regulation of all aspects of the Cyprus natural gas market. In its quest for cleaner energy forms the government intends natural gas to become the island's principal fuel for electricity generation.[45]

As a member of the European Union (EU) since 2004, Cyprus has aligned its energy policy with the acquis communautaire and transposed all relevant EU Directives into national law. The hydrocarbon exploration and exploitation activities in Cyprus are governed by the Hydrocarbon (Prospection, Exploration and Production) Law (4(I)/2007), which transposed into national law Directive 94/22/EC on the conditions for using authorizations for the prospection, exploration and production of hydrocarbons. The said Hydrocarbon Law and the Hydrocarbon (Prospection, Exploration and Production) Regulations (51/2007, 113/2009, 576/2014 and 248/2019) together set out the licensing framework for prospecting, exploring and extracting hydrocarbons in Cyprus's territorial sea, continental shelf and EEZ. It is noted that successful applicants for a licence must enter into an Exploration and Production Sharing Contract (EPSC), in the form published by the Ministry.

(a) Licensing

Any entity wishing to engage in construction, importation, storage or gasification facilities for natural gas or in the operation and use of such facilities must apply for the relevant permit from CERA. A permit by CERA is also required by anyone wishing to supply natural gas to wholesale, specific or unspecified customers as well as anyone wishing to carry out any of the tasks entrusted by Law 183(I) of 2004 to operators of importation, storage, transmission or distribution of natural gas as well as the tasks entrusted to the owners of networks of importation, storage, transmission or distribution of natural gas pursuant to section 8 of the said Law.

In examining an application CERA takes into consideration, among other things, the security of the installation and networks and protection of the environment.

(b) Transmission, Storage and LNG Facilities

Under section 16 of Law 183(I) of 2004, undertakings which own facilities connected with the transmission or storage of natural gas or LNG facilities are obliged to appoint at least one system operator who is responsible for the operation, maintenance and upgrading of such facilities.

[45] A study of the transportation and use of natural gas in Cyprus, undertaken on Order 20/2001 of the Council of Ministers and completed in 2002, indicated that the most cost-effective and secure manner for the supply and carriage of natural gas to Cyprus is in the form of Liquefied Natural Gas (LNG) transported by vessels. The study also demonstrated that in the absence of a centralised distribution network, natural gas might be presently used by the EAC for electricity generation and only at a later stage by consumers.

Such operators have the ability and responsibility to, *inter alia*, operate, maintain and develop under secure economic conditions reliable and efficient transmission, storage and LNG facilities with due regard for the environment and refrain from discriminating between users, particularly in favour of its related undertakings. There are plans for the port of Vasilikos to operate as an oil and gas service center[46]. Furthermore, in December 2019, an agreement was signed in relation to the design, construction and operation of LNG import terminal in Cyprus.

(c) Distribution

Pursuant to sections 21 and 22 of Law 183(I) of 2004, undertakings that own distribution systems are required to appoint one or more distribution system operators whose tasks are operation, maintenance and development under economically viable conditions of a safe, reliable and efficient distribution system, taking into consideration the protection of the environment and energy efficiency.

(d) Vertically Integrated Undertakings

As far as the transmission and distribution systems are concerned, where the relevant operator is employed by a vertically integrated undertaking, the latter must ensure that the operator is independent in a number of matters specified in Law 183(I) of 2004, but this does not create an obligation to separate the ownership of assets from the vertically integrated undertaking.

Offshore Hydrocarbons

(a) Prospecting, Exploration and Production

The Hydrocarbons (Prospecting, Exploration and Production) Law 4(I) of 2007 (the "Hydrocarbons Law") as amended regulates the prospecting, exploration and exploitation of hydrocarbons in conformity with EC Directive 94/22.

Hydrocarbons are defined in section 2 thereof as 'any kind of petroleum in solid, liquid or gas form, including crude oil or natural gasoline, natural hydrocarbon gases as well as any kind of minerals or substances that are extracted with them'. The Hydrocarbons Law sets out the criteria for the assessment of licence applications for the prospecting, exploration and extraction of hydrocarbons in the territory of Cyprus including its Exclusive Economic Zone. According to section 12 thereof these criteria include, *inter alia*, the technical and financial capacity of the applicant, national security and the public interest and the methods envisaged by the applicant for carrying out the activities specified in the licence.

Furthermore, in accordance with section 13 of the Law, the licences may be subject to such terms as may be necessary to protect, *inter alia*, the correct undertaking of the activities permitted by the licence, the payment of a levy in a currency or as hydrocarbons, national security, public health and public safety.

Additionally, pursuant to section 11 of the Law, an environmental impact assessment report must support each application submitted. Furthermore, a Strategic Environmental Assessment (Environmental Report) concerning Hydrocarbon Activities within the Exclusive Economic Zone of the Republic of Cyprus was published in 2008 in accordance with the Assessment of Impact on the Environment of Certain Plans Law 102(I) of 2005.

(b) Model Production Sharing Contract

The Ministry of Energy, Commerce and Industry prepared a model exploration and production sharing contract to be concluded between each selected licensee and the government for the exploration of the Exclusive Economic Zone and the exploitation of its hydrocarbon reserves.

[46] C. Stamatiou, V. Psyrras, Y. Georgiou, I. Sidiropoulos of Elias Neocleous & Co LLC, Ports & Terminals 2020, Law Business Research Ltd , October 2019, https://www.neo.law/2019/12/30/ports-and-terminals-2020-contribution/ generation and only at a later stage by consumers.

Pursuant to section 6(7) of the Hydrocarbons (Prospecting, Exploration and Production) Regulations, 51 of 2007 (the Hydrocarbons Regulations), when the specific terms and conditions of a contract have been negotiated and agreed with the selected party, it will be forwarded to the Council of Ministers for approval and for the issue of the relevant licence.

Under article 32, the contract and the hydrocarbons operations carried out under the contract are governed by Cyprus law and the contractor is subject to the legislation of the Republic of Cyprus.

(c) Types of Licences

In the Hydrocarbons Regulations, the government has published detailed rules on the types of licence available and the procedural requirements that need to be satisfied by applicants. These licences will be valid for a period of up to one year under section 8 of the Hydrocarbons Regulations. Their purpose is the evaluation of potential by the identification of geological structures and drilling is not permitted under this type of licence.

These licences will be valid for three years with the possibility of two renewals, each for two years under section 9 of the Hydrocarbons Regulations. Holders of the licences will have the right to carry out gravity and magnetic surveys, two and three-dimensional seismic surveys and exploratory drilling. On each renewal, 25 per cent of the initial licence area will be relinquished. In the case of a discovery, the licensee has the right to be granted an exploitation licence for that discovery under s 10 of the Hydrocarbons Regulations.

These licences will be granted for an initial period of up to 25 years with the possibility of one renewal for up to 10 years under section 11 of the Hydrocarbons Regulations.

(d) Applications

Applications for exploration licences must contain, in addition to the information required for prospecting licences, information about the applicant's organisation, including general and financial information on parent and affiliated companies as well as annual reports, balance sheets and any other reports filed by both the applicant and its parent company with the relevant securities and stock exchange authorities for the previous three years under section 6 (2) of the Hydrocarbons Regulations.

According to section 27 of the Hydrocarbons Law and section 12 of the Hydrocarbons Regulations, any licence and the rights deriving from it may be transferred and assigned to another entity on application to and consent from the government.

Following section 13 of the Hydrocarbon Regulations, the licence holder is obliged to, *inter alia*, abide by the legislation relating to the safety and health of workers and ensure that all equipment, supplies, machinery and structures are of an acceptable standard, properly constructed and maintained in good operating condition.

In accordance with section 15 of the Hydrocarbon Regulations, the licensee must ensure that the hydrocarbon activities are conducted in an environmentally acceptable and safe manner, must take all necessary measures to restrict any environmental pollution or damage to the minimum and must comply with any applicable international convention such as the International Convention on Civil Liability for Oil Pollution Damage 1975 and its Protocol of 1976 as amended.

7.4.6 Exclusive Economic Zone

Overview

The delimitation of Cyprus's Exclusive Economic Zone was a significant milestone in the country's history. The significance of this maritime zone lies in the fact that there are within the seabed potentially extensive oil and gas reserves that may be exploited. Cyprus is a signatory to the United Nations Convention on the Law of the Sea of 1982 (UNCLOS).

Section 8 of the Exclusive Economic Zone Law 64 of 2004 (article 56 of UNCLOS) provides that no person, whether legal or natural, may proceed with the exploration and utilisation of any resources within the Exclusive Economic Zone of the island unless a permit is granted for such purposes. The reason for this is that the nature of the Exclusive Economic Zone is jurisdictional and includes the sovereign rights of the coastal state.

It is explicitly stated in section 4 of Law 64 of 2004 that the Republic of Cyprus has jurisdiction within its Exclusive Economic Zone over:

- The exploration, utilisation and management of all natural resources, the waters, the seabed and the soil underneath the seabed;
- The production of energy;
- The establishment and utilisation of man-made islands, installations and struc- tures;
- Scientific research;
- The protection and preservation of the environment; and
- Other rights and duties provided by the UNCLOS.

It is noteworthy that the EEZ of Cyprus was delimited by bilateral agreements with Egypt, Lebanon and Israel in 2003, 2007 and 2010 respectively.

With respect to other neighbouring countries, the law provides that where any areas of the Contiguous Zone or the Exclusive Economic Zone of Cyprus overlap with the respective zones of another state located opposite its shores, the boundaries of these zones are set, in the absence of an agreement, in such a manner that they do not extend further than the median line or a line of equal distance from the base lines of each country. [47]

Oil and Gas Taxation

In order to bring off shore activities within the scope of taxation, the government has amended the Income Tax Law (Law 118(I)/2002) by adding the following text to the definition of the Republic of Cyprus: " *includes the national territory, the territorial waters, as well as any area outside the territorial waters, including the border zone, the EEZ and continental shelf, which are determined in accordance with the laws on the EEZ and Continental Shelf and Territorial Water Laws, as well as any installation, construction and artificial islands located in these zones in which the Republic of Cyprus exercises sovereign rights or jurisdiction*".

7.5 GREECE

7.5.1 Introduction to the energy market

Greece's strategic geo-economic location, between energy producers in the Middle East, North Africa, and the Caspian Sea region, as well as on the vital transport routes of the Aegean Sea and the Eastern Mediterranean, characterises it as the expanding hub between East and West. Greece has initiated crucial, major ventures in oil, gas, and alternative sources that put the country at the heart of the Southeast European energy axis.

Greece's comprehensive energy policy, which seeks to establish sustainable, competitive, and secure sources of energy, has put forth an encompassing regulatory and market framework for the energy sector. This, in combination with Greece's wide-ranging investment regulatory framework, provides for exceptional opportunities for investment.

Nowadays, Greece has a liberalised energy market that has evolved in the last decade into an energy hub and represents an important sector of the country's economy. Electricity and gas agreements with major European, American and Asian companies have positioned Greece as a point of reference in the region, and a number of energy projects linked to wider geopolitical moves and to the largest global economic players are expected to be implemented in Greece. Despite the current economic crisis and its impact on the Greek economy, a number of recent developments

[47] Stamatiou, 'Establishing the Boundaries: Cyprus Offshore Oil, Gas and Shipping Industries' Lloyd's List, Cyprus, September 2005

and significant reforms across all sectors of the economy are expected to put Greece on a new course.

7.5.2 Electricity

Market overview

The Greek government passed in 2011 an energy law that, amongst others, implemented the EU's Third Energy Directive and paved the way for increased competition in the country's energy markets by advancing the unbundling of the incumbent public companies as well as by giving the country's regulator much stronger powers. Greece is currently in the process of a complete restructuring of its electricity market in order to conform with the rules for market integration, based on the European Target Model for electricity.

In 2018, Greece's total net installed capacity is 17.4GW and consumed 50.9TWh of electricity. According to figures published by the Electricity Market Operator, Greece in 2018 generated a total of 44.9TWh of electricity.

Regulatory overview

The Greek electricity market has been shaped by a series of key legislative acts over the past 20 years. Such legal framework[48], along with the Grid Codes and a series of secondary legislation in the form of Regulations, Ministerial Decisions and other Administrative Acts, establish the organisational and operational rules for the electricity market, as well as the fundamentals and the restrictions of the market organisation and of the lately introduced energy exchange market.

The regulatory authorities that oversee and regulate the Electricity market are:

- The Regulatory Authority for Energy ("RAE"), an independent authority that supervises and monitors the operation of all sectors of the energy market, and advises the competent authorities on compliance with competition rules and consumer protection;
- The Ministry of Environment and Energy ("MEE"), which is principally responsible for the formulation and implementation of Greece's energy policy in relation to its international and EU Community ("Community") obligations i.e. the transposition of relevant EU Directives and the alignment of the national policies with the EU Regulations and strategies; and
- The Ministry of Economy and Development, which can indirectly affect energy matters through its monitoring of petroleum product prices and, more significantly, through its responsibility for administering EU Cohesion Funds.

The key market players of the Greek Electricity market:

- The Public Power Corporation ("PPC" or "DEI" as per its Greek initials) is the dominant electricity producer and supplier in Greece. PCC also owns the distribution network. PPC is owned by the Greek State (51.12%) and several insurance funds (3.93%), with the remaining percentage (44.95%) held by private investors.
- The Hellenic Distribution Network Operator ("HDNO" or "DEDDIE" as per its Greek initials), a wholly owned subsidiary of the PPC resulting from the separation of its distribution segment under the Energy Law. DSO is independent in its operation and management, retaining all the independence requirements that are provisioned in the Energy Law. DSO is responsible for all activities relating to the maintenance and development of the electricity distribution network, as well as for the assurance of a transparent and impartial access of consumers and of all the network users in general.
- The Independent Transmission Operator ("ITO" or "ADMIE" as per its Greek initials),

[48] These laws are: Law 2773/1999 on the liberalisation of the Electricity Market; Law 3175/2003 which amended Law 2773/1999 (the "Electricity Law"); the Grid Control and Power Exchange Code for Electricity of May 2005 ("Grid Code"); Law 3426/2005 on the Acceleration of Electricity Market Liberalisation; Law 3468/2006 on the Production of Electrical Energy from Renewable Energy Sources; Law 3851/2010 on the Acceleration of the development of RES and the Climate Change ("New RES Law"); Law 4001/2011 on the Operation of the Electricity and Natural Gas Energy Markets and for the Research, Production and Transmission Networks for Hydrocarbons and other provisions ("Energy Law"); Law 4389/2016 regarding the NOME auctions and implementation of Ownership Unbundling; Law 4414/2016 on the New RES and Combined Heat and Power ("CHP") Support Scheme; Law 4425/2016 regarding the new operational model of the wholesale electricity market in Greece; and Law 4512/2018 ("Target Model Law").

and transmission system operator ("TSO"), which up to July 2017 was a subsidiary of PPC, is the owner and operator of the High-Voltage Transmission System ("System") and accordingly is responsible for its operation, exploitation, development and maintenance as well as for the operation of the balancing market. Following full ownership unbundling ("FOU"), PPC has fully divested its interest in the TSO and the present shareholders are the State Grid Europe Limited (a 100% subsidiary of State Grid International Development Ltd), controlling 24% of the TSO; the Public Holding Company ADMIE (IPTO) SA, owned 100% by the Greek State, controlling 25% of the TSO, and ADMIE (IPTO) HOLDING SA, listed in the ATHEX (51% is owned by the Public Holding Company ADMIE (IPTO SA), controlling 51% of the TSO.

- The Operator of renewable energy sources ("RES") and Guarantees of Origin SA ("Operator of RES" – previously the Electricity Market Operator ("LAGIE" as per its Greek initials)), is the RES operator, which is exclusively controlled by the Greek State. The RES operator is responsible for the operation of renewable energy sources ("RES") and guarantees of origin ("GOs") and its activities are carried out in accordance with the Code of RES Operator and Guarantees of Origin.
- The Hellenic Energy Exchange SA ("HEnEx") was established in the context of the reform of the Greek energy market, i.e. towards its harmonisation with the requirements of the Target Model. The Target Model introduced the general framework of the new operating model of the wholesale electricity market ("Target Model"). The registered shareholders of HEnEx are: Operator of RES (22%), Athens Exchange Group (21%), ADMIE (20%), EBRD (20%), Hellenic Gas Transmission System Operator SA ("DESFA") (7%) and Cyprus Stock Exchange (10%). Under the new framework, LAGIE assigned/contributed all of the activities that were relevant to the operation and the management of the Day-ahead Scheduling ("DAS"), including the organisation and implementation of the auctions for the sale of electricity forward contracts ("NOME" auctions), for the purposes of establishing the Hellenic Energy Exchange SA (by way of spin-off). HEnEx is responsible for the administration and the operation of the day-ahead market, the intraday market, and the energy financial instruments/products market. HEnEx needs a licence from RAE to perform the above activities, and a licence from the Hellenic Capital Market Commission for the energy financial instruments/products market.

The Greek wholesale electricity market continues to be under complete restructuring due to the implementation of the Target Model, to ensure conformity with the requirements of the EU Target Model and enable its connection with the European markets. Auctions in accordance with the NOME model have been taking place since October 2016. The auctions enhance competition between power suppliers by providing all power suppliers access to the less expensive lignite electricity production of the dominant power producer (i.e. PPC).

Despite the fact that the Greek State enacted Law 4425 in 2016 in order to reorganise the electricity market in accordance with EU rules, for the completion of the single European market, the initial version of the law adopted a very conservative approach in introducing the principles of the Target Model, which proved to be inadequate. Law 4425/2016 was criticised for not having achieved the introduction of the required regulations. It was more of a law primarily acknowledging the Target Model instead of introducing a completely open environment for its implementation.

The enactment of Law 4512/2018 introduced an evolution in the energy legislative sector; Law 4512/2018 adopted decisive steps among which was the establishment of HEnEx followed by the structural reformulation of the particular and individual sectors of the energy market.

HEnEx provides access to new liquid energy markets and products that will, among other things, support greater the domestic competition, reduce barriers to entry for new energy market participants and allow the effective participation of renewable energy producers in the electricity markets. HEnEx will also support regional integration by facilitating market coupling with Greece's neighbours (i.e. Italy and Bulgaria).

Furthermore, HEnEx offers a comprehensive set of new energy trading products well above the minimum requirements for compliance with the EU Target Model, including new spot plus new physical and cash settled energy derivative products. Through the introduction of physical and cash settled energy derivative products, HEnEx is the platform that accommodates domestic and regional market participants with the opportunity to hedge their electricity market risk in different time frames, as well as to improve price discovery across the curve.

Electricity market structure

Before the target model

The operation of the electricity market is a licensed activity, currently based on a mandatory wholesale daily market ("Pool") for power exchanges between market participants and is mainly comprised of DAS and the real time dispatch of generation units. By registering with the participant register kept by HEnEx, participants enter into a DAS contract and a TSO contract, governed by the provisions of the Power Exchange Code for Electricity, and the Grid Code respectively. DAS and TSO contracts are not subject to any other formalities. Other forms of contracts or industry standard instruments are not in use under this restrictive framework. Registered market participants are invited to submit to HEnEx their load nominations and injection offers for any hour (i.e. dispatch hour) of a calendar day (i.e. dispatch day) until 12:30 of the previous day. Within the framework of DAS, all power exchanges between suppliers and generators are settled at a uniform system marginal price ("SMP") per dispatch period (SMP in €/MWh).

Following the dispatch day, the TSO activates the imbalances settlement procedure, which results in a uniform price at which the TSO settles the relevant charges and credits to the participants concerned and encourages the availability of generation units. The TSO Code includes terms concerning the provision of Ancillary Services, Supplementary System Energy and emergency reserves by the market participants that enter into the respective contracts with the TSO. With respect to the remuneration for the capacity availability of the power plants, a transitory mechanism was introduced by Law 4559/2018 and provided for the remuneration by TSO of flexible plants (ie plants that are capable of increasing or decreasing electricity generation at a rapid rate). The PPC lignite fired power plants do not meet the technical criteria to participate in this mechanism.

This mandatory pool operating model, consisting of DAS and the supplementary mechanisms was changed due to the introduction of the Target Model which, on its full implementation, enables Greece's participation in the EU Market Coupling and enables bilateral agreements between market participants. This restructuring process, which is part of the complete liberalisation of the electricity market, is ongoing.

The energy market after the enactment of the Target Model Law

Laws 4425/2016 and 4512/2018 ("Target Model Law") introduced the general framework of the new operating model of the wholesale electricity market (i.e. the Target Model) and implemented in 2019, as a result of several years of harmonisation efforts with the EU legislative regime.

The Target Model Law introduces the following wholesale markets:
- day-ahead market (operated by HEnEx);
- intraday market (operated by HEnEx);
- imbalances market (operated by ADMIE); and
- energy financial (financial instruments/ products) market (operated by HEnEx).

The newly created market structure is primarily based on the day-ahead market. In this market, the electricity transactions are carried out on a 'physical delivery' mode. Therefore, the market involves cash settled transactions of immediate delivery and does not involve transactions of forward energy products. The day-ahead market is coupled by an intraday market and a balancing market. The Target Model Law provides for the operation of the intraday market. In the intraday market, physical delivery transactions are carried out according to orders submitted after the end of the submission period in the context of the day-ahead market. The day-ahead market and the intraday market contribute in advance to the balancing between offer and demand as such a function relies on the estimations of the day-ahead demands.

There lies the importance of the balancing market, which is the mechanism for the account of imbalances between offers and demand of electricity, given that if there is an imbalance in the performance of the contracts for the delivery of electricity products on an hourly basis such imbalances are settled by the balancing market.

The Target Model Law provides for alternative options with respect to the clearing and settlement of the transactions of the day-ahead market and of the intra-day market which may be carried out by HEnEx or a clearing house or a central counterparty ("CCP") of the European Market Infrastructure Regulation ("EMIR"). The second option is currently adopted, which provided that the clearing and settlement of the transactions of the day-ahead and the intraday market will be carried out by a clearing house established by HEnEx. The clearing house was created in November 2018 under the distinctive title "EnExClear SA", which will become operational following the issue of respective operation licence and the approval of its Regulation by RAE and on the same day as the operation commencement date of the new day-ahead market and of the intraday market, as this date is set by RAE.

The Target Model Law provides that the clearing of the balancing market transactions will be carried out by ADMIE, which is entitled to assign certain clearing functions to a clearing house or a CCP on RAE's approval. In relation to the clearing and settlement of the energy financial market transactions, see the last section of the present paragraph.

The HEnEx market and the introduction of the financial instruments/products

The Target Model Law establishes a significant expansion of the available electricity trading mechanisms by introducing the energy financial instruments/products. In such a market, these financial means are negotiable instruments and are meant to be, provided that they are related to energy goods, the ones defined as financial instruments and provisioned in the cases 5-11 of Annex 1 of the MiFID II.

Depending on the maturing and the widening of the Greek electricity market, it is now institutionally possible for such contracts to appear in the Greek energy reality. It also remains to be seen in the future whether said agreements shall be formulated so as to be cleared-settled only through the physical delivery of electricity power or through cash (economic) settlements. In particular, transactions over energy financial products can be concluded outside the HEnEx market through bilateral contracts directly between the contractual parties.

The Target Model Law provides that, in relation to the operation of the Energy Financial market, HEnEx receives a licence from the Hellenic Capital Market Commission. Additionally, HEnEx must enter into the necessary agreements with the Athens Stock Exchange SA ("ATHEX SA") and its subsidiary company (i.e. the Clearing House of the Athens Stock Exchange Company SA ("ATHEXClear SA")) in order that ATHEXClear or another company linked to ATHEX undertakes the clearing of the transactions. By way of exception to the above provisions, HEnEx is entitled to operate an organised trading facility ("OTF") on derivatives physically settled, and to carry out the clearing process of the OTF on RAE's approval.

The transformation of the regulatory landscape: from codes to regulations

The Target Model introduces, from a systemic perspective, the requirement to issue specific regulations for each market section, as the markets are now regulated. Before the introduction of the Target Model Law, the regulatory framework was organised, technically, with the adoption of codes, whereas under the Target Model, the form of regulations has been introduced as the instrument to regulate the related market specifics. Given this approach, the adoption of the Regulation of the Energy Exchange Market ("EEM Regulation") was effected at the end of 2018 on the recommendation of the Board of Directors of HEnEx following the approval by RAE. The EEM Regulation sets out the terms and conditions for the operation of the day-ahead market, as well as the intraday market on the basis of objective and transparent rules in the absence of any discrimination with regard to the access of the participants in those specific markets.

In addition, as also required by the Target Model Law, as of the end of 2018, the Regulation of the Balancing Market ("BM Regulation") was affected following RAE's approval of ADMIE's recommendation. The BM Regulation sets out the terms and conditions for the operation of the balancing market on the basis of objective and transparent rules in the absence of any discrimination relating to the access of the participants in the markets in question. Furthermore, the rules and procedures for carrying out the transactions in those markets, as well as the connection thereof with the settlement mechanism and the consequences of a breach of its rules are addressed in BM Regulation.

The introduction of the Regulation on the Clearing of Transactions ("CT Regulation") constitutes an innovation of the Target Model Law. The CT Regulation seeks to establish under new grounds the concept of clearing and settlement according to the type of transactions settled, and the intermediary who will undertake the relevant role that is crucial for the operation of the market. Article 18§3 of Law 4425/2016 sets out the material contents of the CT Regulation, which include the rules for access to the clearing functions, the obligations of the clearing members, the rules governing risk management along with the provisions relating to the securities for safeguarding the claims incurred from the transactions settled.

If a CCP of the EMIR, which has been licensed in Greece under Article 100 of Law 4209/2013, undertakes the clearing of transactions of the day-ahead and the intraday markets, the clearing process is conducted according to the CCP's Regulation, which is drawn up in accordance with EMIR and the CCP Technical Standards Regulation. Within the above rules and their scope of application, the potential clearing of the balancing market by such CCP, is also applicable expressis verbis. The structural amendments effected by the Target Model Law, resulted in the adoption of the Code of RES Operator & Guarantees of Origin.

Regulated electricity market activities

According to Laws 2773/1999 and 4001/2011, as amended and in force, the main activities which fall under the general term "Electricity market" are the sale and purchase of electricity and all related commercial activities (such as generation, transmission, distribution, supply, import and export, etc.). In order for these activities to be lawfully performed, interested parties must obtain the relevant licensing.

Material licences for electricity generation

Law 4001/2011 "On the Operation of the Electricity and Natural Gas Energy Markets and for the Research, Production and Transmission Networks for Hydrocarbons and other provisions" together with Law 2773/1999 "on the Liberalisation of the Electricity Market" as amended and in force today, transposed the relevant EU Legislation into domestic law and set out the framework for the licensing of power generation facilities in Greece.

Under Greek electricity legislation, the development, construction, commissioning and operation of a power plant is extensively regulated by a number of legislative acts (including voluminous secondary legislation).

The licensing process can be divided into three basic licenses:

- The Electricity Generation Licence, issued by RAE upon review of the criteria stipulated in the Energy Law, which can only be granted to legal entities based within the EU and/or EU citizens.
- The Installation Licence, in conjunction with the environmental licensing of the respective facilities, which is a prerequisite for every developer wishing to proceed with construction works, enter into agreements with the relevant operators for the connection of the power plant with the grid and the sale of the electricity produced. It is also a prerequisite for gas-operated power plants that enter into an agreement for the connection of the power plant with the natural gas transmission system.
- The Operation Licence, issued following the connection of the power plant with the grid, the completion of the works and the successful trial operation.

The above licences are without prejudice to any other ancillary requirements which may be prescribed by the general legislation, e.g. building permits, health and safety legislation, etc., which may run in parallel or as a prerequisite to reaching the next milestone.

Trading and supply of electricity

The issuance of an Electricity Trading and or Supply Licence is regulated by the Energy Law and the provisions of the Electricity Licensing Regulation. Both the Energy Law and the Electricity Licensing Regulation differentiate the criteria for the issuance of these licences on the basis of the type of the licence requested, and the legal form of the applicant entity, among other things, while concurrently setting additional relating requirements. Under Article 2 of the Electricity Licensing Regulation, an Electricity Supply Licence is provided for the sale of Electricity to End Customers while the Electricity Trading Licence is granted for the conduct of transactions in the electricity market, exclusively through international connections of the country's electrical systems with the electrical systems of neighbouring countries.

Legal entities based within the EU, Member States of the European Economic Area, members of the Energy Community, and/or states that have executed bilateral treaties either with the EU or with Greece are eligible for the issuance of an Electricity Trading and or Supply Licence. Alternatively, an interested legal entity can establish a branch in Greece. The Energy Law also sets out that the exercise of Electricity Supply or Trading activities in another EU Member State under the legislation of that Member State, grants special provision rights with respect to the issuance of the respective licences for the performance of same activities in Greece.

Transmission and grid access

The Electricity market is divided into two different systems: the mainland interconnected grid (including the interconnected islands) and, as they are referred to, the "non-interconnected islands". However, several islands, mainly of the Aegean Sea (most notably Crete with two planned interconnections), are included in the ten-year development plan of ADMIE for gradual interconnection with the mainland grid system through submarine cables. The distinction between the two systems is of importance because different rules on licensing procedures and compensation schemes are applicable for each system.

According to the provisions of the Electricity Transmission System Operation Code, all power producers are entitled to gain access to the System or the Network under specific financial and technical terms concerning the connection of the power plant to the electricity grid, as such, are determined by the relevant Operator in the Connection Terms Offer.

At a later stage, power producers enter into a Connection Works Agreement with the relevant Operator of the System or the Network, which describes in detail the connection works required for the connection of the generation facilities to the grid, along with the financial and technical terms of the connection.

7.5.3 Renewable energy

Market overview

Renewable energy plays a significant part in the Greek energy production and was initially based primarily on large scale hydropower stations operated by the PPC.

To establish security and diversification of its energy supply, as well as to promote environmental protection and sustainable development, Greece has established key priorities and binding policies related to the production of electricity from renewable energy sources ("RES") and promotes the establishment of RES plants.

RES play an increasingly important role in Greece's energy production profile. The increase in energy production from RES has mainly been led by photovoltaics ("PVs"), wind parks and hydropower stations, while the other RES technologies have not shown significant progress, mainly due to the economic crisis and difficulties in securing the necessary financing.

Based on the EU mandate (Directive 2009/28/EC) and Law 3851/2010 on RES Development the national target for RES states that the energy produced by RES will contribute 20 per cent of the gross final energy consumption, whereas the electric power produced by RES will contribute at least 40 per cent of the gross electric consumption, by 2020. The aforementioned targets were attempted to be achieved through a mix of measures related to the implementation of policies in the field of energy efficiency and the large penetration of RES technologies, both in electricity production and heat supply.
The recent global economic crisis generally, and Greece's debt crisis specifically, affect the country's growth rate. However, Greece follows a long-term plan to reform and modernise its energy sector and it has taken several steps along this direction by revealing a number of competitive advantages, such as:

a. a comprehensive regulatory framework for energy investment;
b. excellent potential of every renewable energy resource;
c. attractive investment incentives;
d. renewable energy project development at competitive costs; and
e. continued expansion of the energy market for spin-off markets in manufacturing energy technologies.

In addition to simplifying the licensing process for RES projects, the Greek State also has a fast-track process for large-scale energy, tourism, industry, advanced technologies and innovation projects that fall under the scope of the investment law. It is currently being used as a tool aimed at accelerating large-scale investments in Greece, with most of those investments being in RES projects.

Support schemes

Another way to promote electricity generation through RES in Greece is by having an attractive compensation mechanism for RES producers. For many years, this mechanism had the form of a guaranteed feed-in-tariff ("FIT") that provided electricity producers from RES a guaranteed sale price for their produced electricity, along with a guaranteed buyer for their production.

However, in order to achieve greater cost-effectiveness and to incentivise better integration into the market of the electricity produced by RES in a cost-effective way through market based instruments, the Greek State replaced the currently applicable FIT scheme with a sliding Feed-in Premium ("FIP") scheme also in compliance with the recent European directives and principles relating to state aid in the energy sector for the period 2014 to 2020 ("EEAG").
The main difference between the two support schemes, however, is related to the obligation of RES producers to participate actively in the wholesale electricity market, once the relevant market codes are implemented, which will lead to the gradual integration of RES technologies in wholesale market conditions. In addition, for PVs and wind parks (and other categories, subject to certain capacity thresholds for

the respective categories), the reference tariff that was previously determined by an administrative decision, is subject to the successful participation competitive bidding processes ("RES Tenders").

Another financial instrument for the promotion of some RES technologies is the National Development Law, which covers almost all private investments in Greece across all sectors of the economy. The National Development Law governs the terms and conditions of direct investment in Greece and provides for incentives, available to both domestic and foreign investors, depending on the sector and the location of the investment.

7.5.4 Natural gas

Market overview

The Greek natural gas market is making significant steps towards its further development. Gas demand was projected to increase in the long term, as it progressively gained a larger market share in power generation, as well as in the industrial, residential and commercial sectors; however, it has slowed down due to the financial recession in year 2017. Interest in entering the market is high as Greece offers a unique advantage for those involved in the business of natural gas due to increasing consumption needs, its geographic position in the region and its potential as an access point for the needs of south-east and mainland Europe.

In particular, Greece is seeking to diversify its natural gas imports by sourcing natural gas from countries such as Iran and Azerbaijan, and is cooperating with several nations that are constructing pipelines. Azeri gas is scheduled to be transported via Turkey through the Trans Adriatic Pipeline ("TAP"), following its commissioning, which will feed with gas form the Shah Deniz gas field. This pipeline is designed to connect with the main line of the NNGS and provide for the transportation of natural gas from Greece to Italy through Albania and its operation is expected to start in early 2020.

Regulatory overview

The primary legislation is the Energy Law, under which gas supply companies (i.e. the Natural Gas-Hellenic Energy Company SA, the Gas Supply Company of Thessaloniki-Thessalia SA, and DEPA) no longer enjoy exclusivity in supplying gas to low and medium pressure customers within the previously licensed (regional) jurisdictions as all customers have become eligible as of January 2018. Such activities are now open to any interested party resulting to the liberalization of the market and its opening to new participants, while suppliers are no longer limited within a specific geographical area.

The exercise of other natural gas activities within the territory of the Greek State, however, under the Energy Law, constitutes a public service and is performed under the supervision and regulation of MEE. Generally, Greek policy regarding gas related issues focuses on:

- ensuring security and continuity of supply;
- protecting consumers;
- ensuring the promotion of free competition and environmental protection; and
- promoting the implementation of energy-efficient and economical, effective practices by the licensees.

The approval of a series of secondary legislation such as the Gas System Code, the Users' Registry, standard contracts and tariffs regulations brings further uniformity and stability in the natural gas market.

The regulatory authorities which oversee and regulate the Natural Gas market are:

- RAE (see above, para. 2.2); and
- MEE (see above, para. 2.2).

The key market players of the Natural Gas market:

- The Public Gas Company SA ("DEPA"), a state-controlled natural gas company vested with the non-exclusive rights to import, export and supply (including trading) natural gas. DEPA is the main natural gas (including LNG) importer in Greece having signed long-term gas supply contracts with Gazprom, BOTAS and SONATRACH. The Hellenic Republic Asset

Development Fund SA ("HRADF") holds 65% of its shares and the remaining 35% is held by Hellenic Petroleum SA ("HELPE");
- The Natural Gas-Hellenic Energy Company SA (i.e. the former Natural Gas Supply Company of Attica-EPA Attica) is a natural gas supplier eligible to supply gas throughout Greece, wholly owned subsidiary of DEPA, which acquired Shell Gas BV's participation in the company at the end of 2018;
- The Gas Supply Company of Thessaloniki-Thessalia SA (formerly EPA Thessaloniki-Thessalia), with the distinctive title "Zenith SA"; since July 2018 Zenith's sole shareholder is ENI Gas e Luce as it acquired the remaining 51% from DEPA;
- The Public Enterprise of Gas Distribution Networks SA ("DEDA") is a wholly owned subsidiary of DEPA, which was established in early 2017. DEDA is the Operator of the Gas Distribution Networks throughout Greece, except for the regions of Attica, Thessaly and Thessaloniki;
- The Gas Distribution Company of Attica SA ("EDA Attica"), since January 2017 is the Operator of the Gas Distribution Network of Attica. It is wholly owned by DEPA following the acquisition by Shell Gas BV's participation at the end of 2018;
- The Gas Distribution Company of Thessaloniki-Thessalia SA (EDA Thessaloniki-Thessalia) was established in 2017 and is the Gas Distribution Network Operator within the geographical areas of the prefecture of Thessaloniki and the region of Thessaly. It is owned by DEPA (51%) and by ENI Gas e Luce SPA (49%) with management rights;
- The Independent System Operator ("ITO") ("DESFA"), the privatisation of which was concluded on December 2018. DESFA, being a certified EU Transmission System Operator and LNG system operator, must, among other things, under Third Gas Directive (Directive 2009/73/EC):
  - operate, maintain and develop secure, reliable and efficient transmission and LNG facilities, ensuring adequate means to meet service obligations;
  - grant third party access to its gas import infrastructures without discriminating among system users;
  - build sufficient cross-border capacity and adopt objective, transparent and non-discriminatory rules for balancing the transmission system, including rules for charging;
  - charge tariffs for the transmission service subject to the approval by the RAE, which is also in charge of monitoring DESFA's investment plans; and
  - avoid any flow of competitively sensitive information.

In order to fulfil these obligations, DESFA develops the NNGS in accordance with the annual Ten-Year Development Plan, as approved and monitored by RAE, outlining the development of the NNGS infrastructures including major capacity expansion works and interconnection projects (e.g. interconnection with the TAP, LNG regasification facilities).

Regulated natural gas market activities

Subject to licensing restrictions, liberalisation has lifted the barriers for entry into the gas market. Specifically, the Natural Gas Licenses Regulation provides for the below licenses granted by RAE and corresponding to the respective activities:
- Independent Natural Gas Transmission System license;
- Independent Natural Gas Transmission System Operation license;
- Natural Gas Distribution license;
- Natural Gas Distribution Network Operation license; and
- Natural Gas Supply license

The initial term of these licences depends on the licensed activity and ranges from 20 to 50 years. Upon request of the licence holder, the licences may be renewed for the same time period. Any other sale, purchase, import and export activities of natural gas activities are conducted freely.

Exploration and production

Natural gas still represents a small percentage of Greece's primary energy consumption, but demand is increasing as natural gas gains a

7

larger market share in power generation and the industrial, residential and commercial sectors. The research, exploration and exploitation activities for hydrocarbons are regulated by Law 2289/1995, which was significantly revised by the Energy Law, introduced in August 2011.

In accordance with the United Nations Convention on the Law of the Sea, as ratified by Law 2321/1995, the right to research, explore and produce hydrocarbons existing in onshore areas, sub lakes and submarine areas, where the Greek State has either sovereignty or sovereign rights, belongs exclusively to the Greek State. Their exercise shall be for the benefit of the public. Following enactment of the Energy Law and by virtue of Presidential Decree 14/2012 the state company Hellenic Hydrocarbons Resource Management ("HHRM" or "EDEY" as per its Greek initials) was established to deal with certain matters relating to the management of the process of research, exploration and production of hydrocarbons as well as the announcement of tenders and tax motives to attract investors. Foreign and Greek companies may submit their requests for research activities directly to HHRM, since HHRM will announce the relative tenders in short notice on companies' requests. The law is referred also to the "open door" tender procedure. Last but not least, the Energy Law includes flexible motives to attract investors.

Transmission and access to the system

The national natural gas transportation system (high-pressure pipelines) has already been commissioned and the distribution systems (medium and low-pressure pipelines) are in a stage of further development.

Transmission

The NNGS includes the main high-pressure natural gas transmission pipeline from the Greek-Bulgarian borders to the region of Attica, the high pressure branches linking various areas of the country with the main pipeline, including the branch connecting the main pipeline with the Greek-Turkish borders, the LNG facility at the island of Revythoussa, as well as additional facilities and infrastructure that service the entire NNGS.

The Energy Law requires DESFA to provide system users with access to the NNGS in the most economic, transparent and direct way, for as long as they wish. DESFA must conclude contracts with system users for transportation and the use of storage and LNG facilities. Such contracts are based on model contracts, the provisions of which are determined by means of Ministerial Decisions following the approval of the tariffs by the Minister and RAE.

Access to the System may be refused in cases of:

(a) lack of capacity pursuant to the special provisions of the system's operating code;
(b) prevention of DESFA from fulfilling its public service obligations; and
(c) serious economic and financing difficulties pertaining to contracts containing "take or pay" clauses.

DESFA must specifically substantiate such a refusal and must communicate its decision and reasons to the authority and the user. DESFA is responsible for balancing the system load - these duties are specified in the system's operating code. In addition, the operator may conclude load-balancing contracts with suppliers following a tender, according to non-discriminatory and transparent procedures and with due respect for market rules. DESFA will also carry out congestion management at the entry and exit points of the system based on market mechanisms and in accordance with transparent criteria, as defined in the operating code, in order to promote non-discriminatory competition between users.

With regard to independent natural gas transportation systems and storage facilities, the operator must conclude contracts for the use of such systems with users, pursuant to a model contract prepared and published by the operator following the approval of the authority and in accordance with the provisions of the respective system's operation code. Access to such systems may be refused only for reasons of capacity or where such access might prevent the operator from fulfilling its public service obligations (unless it is exempt by law from offering such third-party access).

Distribution

The Greek residential and commercial market for natural gas is relatively new when compared to most EU countries. With the support of funding from EU programmes, DEPA has already undertaken and completed the construction of substantial medium and low-pressure pipeline infrastructures in the country's three most densely populated regions (Attica, Thessaloniki and Thessaly) while significant distribution networks are contemplated for the rest of mainland Greece (mainly the north and central parts). The operation of the respective networks has been assigned to regional gas distribution companies (please see above, "key market players", para. 4.2).

The construction and operation of distribution networks in the rest of Greece require a distribution licence, issued following an application under the Energy Law. RAE may grant a distribution network licence upon the application of the interested party, unless state aid or other applications for the same area are involved, in which case the law provides for a tender process, rather than a simple evaluation of the respective application. All distribution and supply companies are required to provide suppliers with access to their distribution networks for the supply of eligible customers, provided that such access does not violate the legislation in force or the respective distribution licences and does not endanger the safe operation of the network.

Trading and supply

Natural gas supply companies are entitled to supply customers with natural gas in their respective areas of jurisdiction pursuant to the terms and conditions of their respective supply licences. Other activities, including wholesale trading and the import and export of natural gas, are not subject to licensing requirements. The Minister's oversight and the RAE's opinions and market monitoring in relation to each licensee's compliance with the terms of its licence constitute the official supervisory framework.

Physical trades in natural gas are determined on the basis of specific provisions in the NNGS operation code prepared by the operator of the relevant transportation system (i.e. the national transportation system or an independent system). Further conditions are determined by the model transportation contracts which give to a gas undertaking access to the national system in order to supply an eligible customer. Given the relatively undeveloped state of the domestic gas market, the completion of financial trades in gas follows the principles that apply to physical trades under natural gas supply contracts. Thus, the physical delivery of a quantity of natural gas (as certified by the system operator) determines the basis upon which the related financial trades are completed.

System users (e.g. importers or suppliers) are able to procure transmission services from the respective system operators irrespective of the natural gas, while customers will pay an access charge for the use of distribution and transportation networks bundled with the commodity. Respectively, tariffs for the basic activity of distribution are determined by the relevant local gas distribution companies following approval by RAE in accordance with the relevant provisions of the tariff regulation.

LNG and storage capacity

LNG terminals constitute energy infrastructures of strategic importance for Greece, as they allow the further diversification of supply sources, provide further supply security and strengthen Greece's impact on the energy environment of the wider region. Greece currently has one LNG import terminal. The terminal is located on the island of Revythoussa, 45km west of Athens.
Additionally, RAE has also approved a floating LNG ("FSRU") terminal in the northern Aegean Sea outside the city of Alexandroupolis, comprising an offshore delivery and regasification station, which will

inject the natural gas into the NNGS through an underwater pipeline contributing to the security of supply in the region.

These projects will ensure that sufficient natural gas quantities reach the Greek market, contributing to the enhancement of the NNGS, all the while promoting the region as access point for South East Europe.

7.5.5 Upstream and the oil market

Market overview

Even though Greece has adopted Law 2289/1995, relevant to research, exploration and exploitation of hydrocarbons for many years (the "Hydrocarbons Law"), it only recently started reinitiated procedures in an effort to improve its productivity in this area.

The rights to research, explore and exploit hydrocarbons located in the national soil, lakes or sea reside solely with the State's public sector, and the use of such must always benefit the State. The Greek State has the power to assign research rights to third parties; exploration and exploitation rights, however, are granted through a tender process.

Hydrocarbons research may be conducted through any possible means, including drilling. Exploitation of hydrocarbons refers to their mining and treatment and does not include refinement procedures.

Regulatory overview

Further to the Hydrocarbons Law, in accordance with the United Nations Convention on the Law of the Sea ("UNCLOS"), as ratified by Law 2321/1995, the right to research, explore and produce hydrocarbons existing in onshore areas, sub lakes and submarine areas, where the Greek State has either sovereignty or sovereign rights, belongs exclusively to the Greek State. The exercise of these rights must be for the benefit of the public.

Following the enactment of the Energy Law and by virtue of Presidential Decree 14/2012, the state company Hellenic Hydrocarbons Resource Management ("HHRM" or "EDEY" as per its Greek initials) was established to undertake the responsibility of particular matters relating to the management of the process of research, exploration and production of hydrocarbons. HHRM is the competent body to grant research licences to third parties following an open tender procedure, following the approval of MEE, for a period of up to eighteen months. The area to be researched cannot exceed 4,000km2 with respect to onshore areas and 20,000km2 with respect to offshore areas. The granting of research licences to several applicants for the same area is permitted. The granting of such a licence is only for the purposes specified and does not confer any other right to the licensee as to its activities.

The holder of a research licence is obliged, immediately after its granting, to submit to HHRM a research programme divided into phases and, following completion of each phase, must submit copies of all technical and scientific data and conclusions that resulted from the research carried out in that phase. Within three months of the expiration of the licence, the licensee must submit to HHRM a detailed report, accompanied by official information and data, in which the results of the research have been analysed. Breach of the foregoing obligations by the licensee, as well as any breach of the terms of the invitation or the licence, may result in the revocation of the licence and in forfeiture of the letter of guarantee in favour of the state.

The State's rights of exploration and production of hydrocarbons are granted to third parties either:

- by the conclusion of a lease agreement; or
- by the conclusion of a production sharing agreement, and in either case both the stages of exploration and production will be provided for. Each agreement will concern one or more adjacent onshore or seabed which will comprise the initial exploration area for the discovery of hydrocarbon deposits ("Contract Area"). The Contract Area will eventually be restricted to the area where commercially

exploitable hydrocarbon deposits have been discovered ("Production Area").

Under both agreements the contractor assumes the obligation to plan and perform the exploration and production of hydrocarbons and their by-products and has the exclusive right to do so. The contractor provides, at its own expense, the necessary technical equipment, materials, personnel and funds required for the performance of the activities and bears the entire financial risk in all events, particularly if no commercially exploitable deposit is discovered or if the profit yield from a deposit is insufficient. The contractor manages the project, which will be carried out in accordance with the international models for the exploration and production of hydrocarbons and under the work programme and budget approved by the employer or the lessor, as the case may be, and bears the risk throughout the entire term of the agreement.

Under the production sharing agreement, in the event of a discovery and production of hydrocarbons, the contractor will retain part of each calendar year's total production of hydrocarbons and by-products of each Production Area in order to cover the relevant expenses specified in the Hydrocarbons Law. The remainder of the production from the Production Area in question together is shared between the employer and the contractor on the basis of a fixed and agreed upon percentage (i.e. production sharing).

Under the lease agreement, in the event of the discovery of a commercially exploitable deposit, the contractor, by notification to the lessor, becomes lessee of the right of production of the deposit. As a result, it is obliged and entitled to produce hydrocarbons and their by-products and to market same for its own benefit, either in their crude state or following processing, excluding refining, by paying to the lessor the rent and the relevant tax. The rent is due to the lessor in all circumstances, irrespective of whether the contractor makes a profit or not. It is agreed that the rent may be paid in kind or in cash, at the lessor's discretion. In the first case, rent will be determined as a percentage of the quantity of hydrocarbons produced and in the second case, as a percentage of their value, as provided under the agreement.

Presidential decrees, which are issued following a proposal of MEE, specify in detail the terms and conditions of the agreements such as the contents and the timetable for the submission for approval of the exploration and production programmes and the expenditure budgets.

HHRM will grant, on behalf of the State, the right to explore and produce hydrocarbons in accordance with the procedures specifically stipulated by the Hydrocarbons Law and more particularly either:

- on an invitation to tender;
- on an application by the interested party for an area not included in the invitation to tender; or
- with an open door invitation for the expression of interest.

Under the agreements concluded, contractors may be natural persons and/or legal entities, acting individually or in a joint venture, provided they have the nationality of, in the case of a natural person, or are registered in, in the case of a legal entity, an EU Member State or a third party country with reciprocity. Following a recommendation by MEE, the Council of Ministers may resolve to prohibit a person who is substantially controlled by a third country (non-EU) or by the citizens of a third country (non-EU) or, a joint venture in which such a person participates, from participating in the procedures and from being granted a research licence or from concluding lease agreements or production sharing agreements and from transferring rights granted under such agreements for reasons of national security. Following the conclusion of an agreement, the contractor may not be placed under the direct or indirect control of a foreign state that is not an EU Member State, or under the direct or indirect control of a citizen of such a state without the prior approval of the Council of Ministers. The Council of Ministers will resolve whether or not to give such approval after receiving the opinion of MEE. Breach of this provision will result in the contractor forfeiting all of his rights under the agreement following a resolution of the Council of Ministers to this effect.

The duration of the exploration stage will be determined in the agreement, but may not exceed seven years for onshore areas and eight years for offshore areas, and may be extended by up to one half of the initial period under specific circumstances. If the contractor finds that the discovered deposit of hydrocarbons is commercially exploitable, he must notify the lessor in writing, within the time limit set out in the agreement, of the commercial exploitability of the deposit and the anticipated amount of its recoverable reserves. The decision as to whether the deposit is commercially exploitable rests with the contractor who must justify his decision in the notice. The duration of the production stage of each area is 25 years and may be extended for up to two five-year periods, on a proposal by the HHRM, when it can be proven that the original duration is not sufficient for the completion of the activities in question. The extension, if given, will include a renegotiation of the terms of the agreement and the signing of a new agreement. The contract must apply for an extension of the production stage before its expiration.

The contractor has the right to transfer, in whole or in part its contractual rights and corresponding obligations to an independent third party only on the written consent of the lessor or employer and the approval of MEE.

The contractor has the right, on the written consent of the lessor or employer and the approval of MEE, to transfer in whole or in part his contractual rights and corresponding obligations to an affiliate enterprise. This is conditional on the contractor remaining wholly, jointly liable with the receiving affiliate enterprise, with respect to the lessor or employer for the performance of his contractual obligations. This consent and approval may be refused for reasons of national security or technical reasons. If the contractor is a joint venture of natural persons or legal entities, each member is entitled to transfer his contractual rights and obligations to another member of the joint venture on the written consent of the lessor or employer and the approval of MEE.

The contractor will be subject to a special income tax of 20%, as well as to a regional tax of 5%, without any other ordinary or extraordinary contribution, fee or other expenditure of any kind for the benefit of the state or of any third party. On expiration of the production stage of each exploration area, the same reverts, free and clear, to the State.

7.5.6 Forthcoming developments in the Greek energy sector

Greece has a liberalised energy market which has evolved over the past years into an energy hub and represents an important sector of the country's economy. Electricity and gas agreements with major European, American and Asian companies have positioned Greece as a point of reference in the region, and a number of energy projects linked to wider geopolitical moves and to the largest global economic players are expected to be implemented in Greece. Despite the economic crisis and its impact on the Greek economy, a number of recent developments and significant reforms across all sectors of the economy have put Greece on a new course. The restructuring and modernisation of the Greek State has caused the markets to start to respond favourably.

Concurrently, the Greek government is reforming the Greek economy by providing a wider range of innovative investment tools to investors who want to explore new investment opportunities across several economic sectors.

The electricity market reform

Within the framework of the Third Energy Package and under the guidance of the European Commission and the International Monetary Fund to promote measures to reform pathogenic structures of the domestic wholesale electricity market, The Target Model Law introduced the general framework of the new operating model of the wholesale electricity market ("Target Model"), which, upon its implementation, will consist of a day-ahead market, an intraday market, the imbalances market, and the energy derivatives (financial instruments -products) market (please refer to para. 2.3).

The Greek State, in order to achieve greater cost-effectiveness and to incentivise better integration into the market of the electricity produced by renewable energy sources ("RES") in a cost-effective way through market based instruments, replaced the applicable Feed-in Tariff ("FIT") Operating Aid regime with a sliding Feed-in Premium ("FIP") regime. This was done in part to be in compliance with the Guidelines on State aid for Environmental Protection and Energy 2014-2020 ("EEAG").

The FIP regime is considered to be an appropriate approach to gradually bring RES as close as possible to real market conditions and balancing responsibilities, preventing the risk of both over- and under- compensating RES producers. The main difference between the two support regimes is related to the obligation of RES producers to actively participate in the wholesale electricity market, once the relevant market codes are in place, which will lead to the gradual integration of RES technologies to wholesale market conditions. The new support scheme for RES and combined heat and power ("CHP") projects was introduced in Greece in alignment with the EEAG. On 4 January 2018, the European Commission ("Commission") approved the proposal and, on this basis, Greece commenced the organisation of the competitive tenders ("RES Tenders"). Under the RES Tenders, as of 1 January 2017, eligible RES projects can only secure a reference tariff for the compensation of the produced electricity through their successful participation in the respective tenders. The first round of RES Tenders was held by the Regulatory Authority for Energy ("RAE") on 2 July 2018.

The implementation of the electricity market reforms is expected to bring the desired results along with certainty and stability to this market, which has been absent recently.

7.5.7 Impact of the coronavirus pandemic on the energy and infrastructure[49]

A. Covid-19 Response Investment and Support Initiative – General

The ongoing crisis of the Covid-19 pandemic has triggered an immediate response from the Greek state, which proceeded to the adoption of a wide array of measures from the early stages of the outbreak. The initiatives, besides of course targeting to limit the spread of the disease among the country's population, directly aim to support the national economy, which has recently entered into a recovery trajectory following many years of recession, on a business as well as on an employee level.

The emergency provisions mainly cover issues of tax; social security and administrative nature as well tend to the facilitation of businesses through financial incentives or other interventions. With regards to taxation, the Government's initiative introduces several emergency tax reliefs, mainly focusing on the suspension of various deadlines, the granting of a refundable cash advance/payment and the reduction of the VAT rate for specific products.

The state has further undertaken to aid the settlement of social security obligations while in the administrative field, the initiative concentrates on measures related to public procurement procedures. While the urgent tax provisions cover all sectors of the economy, social security measures mainly focus on businesses significantly affected by the circumstances. Interventions in the administrative field mostly benefit undertakings that participate in public tenders. All types of private companies and enterprises may benefit from the initiatives, including freelancers and sole proprietorships.

[49] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

In brief, the types of support relating to taxation include:
- suspension of several tax reporting and payment deadlines;
- reduction of 25% in assessed tax liabilities for April 2020;
- reduced VAT rate for products essential for protection against the pandemic;
- a refundable cash advance/prepayment financed by the state's budget for the financially affected businesses; such financial aid shall be tax-exempt; it may not be seized nor set-off against any liabilities.

Social security arrangements comprise of:
- payment by the state of social security contributions of private sector employees, during the suspension of employment thereof;
- postponement of deadlines for payment of social security contributions by employees and employers.

Administrative measures may consist of:
- deferrals of planned public tenders;
- extensions of the applications' submission and other public procurement deadlines; and
- extensions of contractual time-limits.

Other provisions aiming to facilitate the financial and overall sustainability of businesses include:
- the provision of a 40% discount to lessees of commercial leases for the rents of March and April;
- the option of businesses to operate with intermittent employment of the available staff for safety/health reasons;
- the option of intra-group transfer of staff;
- the option of businesses that are severely affected by the health crisis to suspend the existing employment agreements;
- suspension of deadlines for the submission and payment of bank cheques and other financial instruments for 75 days;
- provision of discount to freelancers and sole proprietorships for the timely payment of social insurance contributions;
- possibility of holding Board of Directors meetings through teleconferences;
- facilitation of work from home arrangements for various types of businesses; and
- incentives to financial institutions to proceed to renegotiation of loans to businesses.

A list of Activity Code Numbers (hereinafter "**ACN**") published by the Ministry of Finance on 26 March 2020 sets the exact activities to which the social security, as well as tax emergency regulations, shall apply. Companies that have suspended employment agreements, shall be required not to proceed to any dismissals and retain their personnel over the suspension period.

Undertakings qualifying for tax reliefs further include:
(a) enterprises which have suspended their operation by virtue of explicit governmental decisions;
(b) enterprises (not originally affected) holding securities, whose payment may be suspended; and
(c) small and medium enterprises from all economic sectors employing at least one and up to a maximum of 500 employees as regards the refundable prepayment.

In general, no specific actions are required in order for businesses to become eligible for the implementation of the above initiatives. However, specifically for the refundable cash advance/prepayment, a relevant application should be filed through a dedicated online platform within the specified period.

Therefore, the emergency measures are implemented automatically. Likewise, access to the platform established for the refundable cash prepayment is rather effortless. Nevertheless, the precise timeframe for the actual remittance has not been determined.

The tax provisions initially cover obligations for the period of March and April 2020 and can be extended depending on how the situation evolves. Respectively, social security measures are applicable for the period of February and March 2020 while specifically, the payment of contributions by the state shall cover the 45-day period of their employment suspension. On the other hand, the measures relating to the public tender proceedings shall apply for a period of six months from the date of enforcement (20 March 2020).

In detail, the below tax support measures are designed to relieve businesses in view of the financial impact of the ongoing crisis:

Extension of deadlines:

(1) extension of the deadlines for the payment of VAT obligations, assessed tax liabilities and instalments of assessed liabilities towards the Greek state until 31 August 2020;

(2) extension for the publication of the annual financial reports of companies listed at the Athens Stock Exchange, for the prior fiscal year; as well as for reporting of tax documents for cross-checking purposes of information (MYF) until 30 June 2020;

(3) two months' extension of the deadlines for the submission of capital duty and stamp duty returns whose deadline expires within March and April 2020;

(4) extension until 29 May 2020 of the deadline for the submission of inheritance and gambling profits tax returns, as well as for donations tax returns;

(5) extension of currently pending tax proceedings until 31 July 2020; and

(6) extension of specific deadlines included in the Tax Procedure's Code (regarding the procedures for challenging any assessment act issued by the tax authorities).

Reductions and other measures:

(1) 25% reduction of specifically assessed tax liabilities due between 30 March 2020 and 30 April 2020;

(2) VAT rate reduction from 24% to 6% (until the end of the year) for products necessary for protection against Covid-19; and

(3) acceleration of refunds of income tax and VAT, for amounts below EUR 30,000 per type of tax and per taxpayer, as on 20 March 2020.

The measures for the support of businesses adopted to date do not interfere with the insurance coverage the businesses may retain. Therefore, insurance policies with business interruption, credit insurance and third-party liability coverage may function in supplement to the support mechanisms adopted, provided that such policies cover the insured risks in the case of a pandemic, subject each time to the specific terms and conditions.

Government's websites with relevant information are:

• https://covid19.gov.gr/

The website offers comprehensive information for all issues on the state's response and actions amidst the Covid-19 situation. However, for the time being content is only available in Greek;

• https://www.aade.gr/

The website of the Independent Authority of Public Revenues of the Ministry of Finance, where all the Decisions about tax measures are uploaded; and

• https://www.aade.gr/mybusinesssupport

The online platform where the eligible businesses can apply for the refundable cash prepayment.

B. Impact on the Energy and Infrastructure Sectors

Initiatives directly applicable to the Energy sector were introduced in late March among the several packages of emergency measures adopted by the Greek state.

Measures focusing on RES projects, target to ensure the viability of the investments in the field, include extensions of:

- the duration of installation licences and final grid connection offers expiring within the year;
- deadlines for the acceptance of final grid connection offers and the submission of the relevant letter of guarantee to the competent operator;
- deadlines for the electrification of RES stations which have secured a reference tariff for the produced electricity either through their participation in RES tenders or by operation of law.

Apart from the above, special provisions allow energy companies to procure the necessary supplies in derogation of the applicable

Covid-19 restrictive or lockdown measures in order to ensure the undisrupted supply of materials and spare parts. Furthermore, in order to ensure protection against the spread of the virus, energy companies are required to facilitate and perform transactions with their clients through various long distance means of communication.

2020 was set to be the year marking important developments in the privatisation of infrastructure including significant energy state-controlled companies. These include the Trading and Infrastructure divisions of the Public Gas Supply Company (DEPA Trading SA and DEPA Infrastructure SA), the Public Power Corporation (PPC SA), the Hellenic Petroleum SA (HELPE), the South Kavala Natural Gas Storage, the Athens International Airport, the further privatisation of the Independent Power Transmission Operator (IPTO SA) and others. The unraveling emergency situation, however, has halted the relevant developments. Although no specific announcements have been made to date, besides the extension of the conclusion of the first phase of the DEPA Trading SA process, delays are expected in the majority of the tenders. The Covid-19 measures provide the Hellenic Republic Asset Development Fund, as with other public authorities, the right to postpone, extend or even suspend the tender processes.

Besides, the recent developments indicate that the implementation of the restructuring of the domestic electricity market in conformity with the Target Model will also be delayed. The commencement of operation of the new electricity markets by the Energy Exchange, the go-live date of which according to the applicable framework was set for 30 June 2020 will inevitably be pushed back since the provided date for the necessary simulation tests are already missed.

Overall, the Greek state's early reactions indicate an effort to support the economy in this unprecedented global crisis. The timely implementation of the wide spectrum of measures, however, includes an array of provisions (such as the imposition of a curfew, restriction of movement within the country, closing of borders and limitation of air travel, shutdown of numerous businesses, schools), the combined results of which in the market remains to be revealed in the upcoming period.

Conclusion

Despite the current financial crisis, and unlike other sectors of the economy, the energy sector continues to experience increasing growth with the full support of the Government and both domestic and foreign private investors. Initiatives taken by the Government to ease the regulatory framework and to comply with European directives on the complete liberalisation of the market, along with the positive reaction of investors to large scale investment opportunities in energy, currently define the energy market in Greece.
These developments are the focal point of a comprehensive energy policy that seeks to promote existing clean energy projects, modernise and expand energy-related infrastructure, diversify sources of energy by exploring new energy possibilities through hydrocarbons research, and create new job opportunities and technological innovations.

7.6 KOSOVO

7.6.1 Introduction to the energy market in Kosovo

The Kosovo Assembly in January 2018 approved the latest revised Energy Strategy for Kosovo for the years 2017-2026.Kosovo's main sources of energy are imported petroleum products for transport purposes and domestically produced electricity, under the monopoly of "KEK" (State-owned Kosovo Energy Company). The main power system has two mine mouth generation plants (Kosovo A and B), fed by lignite mines at Bardh and Mirash supplying approximately 7 million tons of lignite per year. There are also several small hydropower plants. Kosovo has a large domestic future energy potential in coal/ lignite and also further potential in hydropower production.

Kosovo's Energy Market is predominantly a regulated market. Kosovo has signed the Athens Memorandum for the establishment of the Energy Community Treaty of South-East Europe that entered into force in July 2006 and is obliged to create free market of electricity and promote competition in the energy market. The government of Kosovo is very much committed to as far as possible developing the energy sector in compliance with acquis communautaire of the Energy Community Treaty and EU.

7.6.2 Electricity

Market overview

The electricity supply in Kosovo is currently unable to effectively meet Kosovo's demand for power. Insufficient investment in new plant capacity and inadequate maintenance of existing plant capacity has led to a substantial shortfall in the supply of power in Kosovo. Some of the existing capacity is reaching the end of its life cycle. Simultaneously, demand for power has been growing and placing increasing the pressures on the system. The overall effect is that Kosovo currently has to import power which is much more costly than relying on domestic production.

In 2006 steps were taken to begin the restructuring or unbundling of the Kosovo electricity sector. The Division Transmission and Dispatch was the first to be unbundled from KEK, and KOSTT JSC-System Operator, Transmission and Power Market of Kosovo was established, which is licensed by the ERO. The remainder of KEK has been restructured in several divisions, such as that of distribution, supply, mining and generation. Kosovo Energy Distribution and Supply Company ("KEDS") is a joint-stock company that operates throughout Kosovo. KEDS J.S.C. has the exclusivity of electricity supply and distribution. KEDS J.S.C was established in 2009, while its operational activities were initiated on May 08 2013, when it finally split from KEK J.S.C.

KEDS J.S.C. is owned by Turkish companies Çalik Holding and Limak. This consortium has offered the highest price in the open bid for privatization of ex-Distribution of KEK. KEDS J.S.C. has 2,618 employees by being as such one of the largest employers in Kosovo. KEDS J.S.C. under the licenses from Energy Regulatory Office operates with electricity supply and distribution to the customers. To operate in the most efficient way, the company is divided in two basic divisions: Supply Division and Network Division, and has within it the supporting departments. To be closer to the customers these divisions are distributed in seven districts located in seven major cities of Kosovo and 30 sub districts in local municipalities. [50]

Private sector participation in the network distribution and supply side of KEK is anticipated to improve and expand the distribution network, increase billing and collections, reduce electricity losses, and improve the security of supply and overall service quality.

Regulatory overview

The Electricity Market in Kosovo is mainly governed by Law No. 05/L-085 on Electricity that establishes common rules for performing generation, transmission, distribution and supply of electricity, Law No. 05/L-081 on Energy and Law No. 05/L-084 on Energy Regulatory Office.

The objective of the Law on Electricity is to:

- develop a competitive and sustainable electricity market, with common rules for generation, transmission, distribution, and supply of electricity, and for access to the market;
- guarantee the conditions for a safe, reliable and permanent generation, transmission, distribution and supply of electricity, adhering to principles of energy efficiency;
- set out the procedures for the granting of licenses, for activities in electricity and for authorizations and tendering for new capacity;

[50] http://www.keds-energy.com/en/about.asp (lastly visited on 27/01/2020)

- provide that all household customers and, when technically and economically feasible to do so, non-household customers, enjoy a universal service, that is the right to be supplied with electricity of a specified quantity and quality, at a reasonable tariff; and
- provide appropriate measures to protect final customers, in particular, adequate safeguards to protect vulnerable customers and customers in rural areas including measures to help them avoid disconnection.

The ERO which is an independent administrative body (institution) established by Law on ERO and is responsible, *inter alia*, for issuing licenses for private energy enterprises such as: (i) generation; (ii) transmission; (iii) distribution (iv) supply of electricity (export or import) and (v) market operations. ERO also monitors the unbundling and restructuring activities of the licensees in the energy sector and their compliance with the technical codes issued: technical rules, market rules, rules for access to land and premises etc. Further the electricity market participants in Kosovo such as licensed companies for the production, distribution, public supply and electricity supply/trade; production, distribution and district heating public supply, and the Transmission System Operator and Energy Market enterprise, report their compliance to ERO on a quarterly and annual basis in accordance with the Reporting Manual.

Licensed electricity activities

The performance of the following activities involving electrical energy will require the acquisition of the following licenses for:

- the generation of electricity (the maximum term of license is 40 years);
- the co-generation of electricity of heat and electricity (the maximum term of license is 40 years);
- the transmission of electricity including Transmission System Operation (the maximum term of license is 30 years);
- distribution of electricity including Distribution System Operation (the maximum term of license is 30 years depending on lifespan of assets);
- the supply of electricity (the maximum term of license is 25 years);
- export or import (the license terms shall not be less than 1 year but not more than 5 years);
- market operations (the terms of license will depend on competitive selection process opened by the Government).

The activities that do not require a license include generation of electricity at an electricity site with total capacities lower that 5 MW, and the generation of electricity for personal consumption.

Functions of the Market Operator

The duty for the implementation of a competitive market model for the electricity sector is given to the Transmission System and Market Operator ("KOSTT") a duly licensed state-owned entity by the ERO. The Market Operator operates independently from any enterprise engaged in any electricity activity other than transmission. The Law on Electricity does provide that the Market Operator will be a legal entity responsible for the organization and administration of the market for trade of electricity and payment settlements among producers, suppliers and customers. The Market Operator balances financial supply and demand ahead of time.

KOSTT is responsible for the economic management of the electricity system and its primary functions *inter alia* include:

- keeping records for all contractual obligations between suppliers and eligible customers;
- notifying participants in trading and the transmission system operator of the settlement process, planning network access based on the settlement and the price of the remaining energy offered;
- accepting information from the transmission system operator regarding the settlement changes required based on technical capacity and any exceptional situations in the transmission or distribution network;
- setting the final price of energy for each specified time period and notifying all parties involved in trading;
- establishing the accounting system for trading

at the final price achieved, and providing information on the actual operation of the generators and availability of generation capacity for each time period;
- public announcement of market trends for any required time interval.

KOSTT performs its functions with due respect to the principles of transparency, objectivity and independence.

Distribution and grid access

As provided under the Law on Electricity, the Grid Code is drafted by the KOSTT (Transmission System and Market Operator) and approved by the ERO. The Grid Code covers the operating procedures and principles governing the interactions between the KOSTT and the users of the Kosovan transmission system. It covers the processes of planning, connection, operation and system balancing in both normal and exceptional circumstances. The Grid Code is a mandatory document for both the KOSTT and the users. Also the KOSTT has drafted the Metering Code aiming to establish clear rules for the instalment and use of metering devices to ensure that production, transfer and consumption data are available to support an efficient process of electricity transactions. Another important document prepared by the KOSTT is the Distribution Code, which is a set of provisions defining all technical aspects of the work between the Distribution System Operator and all users of the Distribution System, in order to provide an efficient, co-ordination and an economic system for distribution of electricity. Also, this code enables DSO to comply with the responsibilities arising from the Distribution System Operator License, the Grid Code and the Metering Code.

Trading of electricity

According to Energy Legal Instruments trading energy prices shall be comply with tariff-setting methodology by the ERO which is entitled to set the methodology of following tariffs: Transmission and Distribution System Connections; Wholesale Price Tariff and Retail Sales Tariffs, Coal Royalty which are proposed by energy enterprises.

7.6.3 Renewable Energy

Market Overview

Kosovo has substantial potentials for expanding the use of renewable energy sources in electricity generation. The biggest potential sources are wind, hydropower, biogas, and others include solar, geothermal and biomass.

The issue of renewable energy is a relatively new practice in Kosovo, taking into consideration that over 90 per cent of electricity relies on thermal power plants. For the time being hydropower and biomass in the form of wood are the only renewable energy sources used, which contribute substantially to the energy supply in Kosovo. The use of solar energy is still in the very early phase (few pilot projects for water heating situated in some public buildings, financed from MED)[51]. Two projects with solar energy started the commercial operation on 06.11.2018. These projects have been finalized by energy purchase agreements for electricity generation from RES, signed for a period of 12 years with KOSTT/MO.

Currently in Kosovo there are some active hydropower plants with small generation capacities. The majority of the smaller Hydro Power Plants (HPP) throughout Kosovo produce electricity independently but are connected to the transmission and/or distribution networks. The Hydro Power Plant "Ujmani" is administered by publicly owned company "Iber-Lepenc" and Hydro Power Plants "Lumbardh" and "Lepenc " administered by differentprivate companies. The generation capacities of the rest of the HPPs among which are HPP "Belaja", "Brodi 2", "Brezovica", "Radavc". According to Kosovo Agency of Statistics (ASK, 2019), the total hydro energy available for consumption in 2018 amounted to 28.84 ktoe.

[51] http://www.euroqualityfiles.net/AgriPolicy/Report%202.2/AgriPolicy%20WP2D2%20Kosovo%20Final%20Rev.pdf (lastly visited on 18/10/2011).

7

Based on the Energy Regulatory Office data (2019), electricity generation capacities available in 2018 for:

- operational capacity of thermal power plants amounted to 960 MW;
- active hydro capacities amounted to 76 MW;
- active wind capacities amounted to 33.75 MW;
- active solar capacities amounted to 6.6 MW.

Based on the Energy Strategy, the Government policy is to develop small Hydropower Plants with private investments by granted concessions on the right to use the water for power generation in order to fulfil objectives of EU plan 20-20-20 by 2020, to increase the use of renewable energy sources to 20 per cent. Moreover, pursuant to Administrative Instruction No. 01/2013 on Renewable Energy Targets, the mandatory target for consumption of renewable energy until 2020 is 25 per cent as it is determined in Article 4 of the Decision rendered by the Ministerial Council of the Energy Community.

Support Schemes

Pursuant to the Energy Strategy, the goal of the Government is to attract private investments in the development of projects on renewable energy sources in line with EU directives on Energy Efficiency and Renewable Energy Resources.

Pursuant to the Energy Strategy of the Republic of Kosovo 2017-2026 and the applicable legal framework, Kosovo has adopted a system of feed-in tariffs aimed at stimulating electricity generation from water, wind and biomass (including biogas). The Energy Strategy pays special attention to the full adoption of European Union RES policies, through the implementation of all obligations deriving from the Energy Community Treaty (EnCT). The strategy places special emphasis on the development of Hydro Power Plant Zhur and other smaller hydropower plants. [52]

The Kosovo Law on Electricity suggests the use of feed-in tariffs as well as the use of Certificates of Origin (CoO) as components of a support scheme for promoting RES-E (RES for electricity generation) development. The international experience suggests that feed-in tariffs are particularly effective in promoting the use of renewable energy in electricity generation. Investors prefer feed-in tariffs because they provide certainty on the revenue stream from the sale of electricity produced from renewable.

ERO has adopted also the Rule for Support Scheme for RES with these main objectives: (i) to promote the development of electricity generation capacity using renewable energy sources in a transparent manner; (ii) to attract domestic and international investors by providing a conducive environment for investing in generation capacity using renewable energy; (iii) to support, or at least not hinder, the development of a competitive electricity market, in Kosovo or regionally, when the conditions of the electricity sector(s) allows it; (iv) to be compatible with Kosovo participation in "Joint Projects"33 with EU Member States, as envisaged in Article 9 of Directive 2009/28/EC; and (v) to be simple and cost-effective to implement. Power Purchase Agreements (PPAs) for electricity produced by RES are part of the policy and regulatory incentives. ERO has also adopted: (i) the Rule for Issuing and Usage of Certificates of Origin (CoO) in respect to electricity produced from RES, Waste and from Cogeneration, and (ii) Feed-in tariffs.

Future Developments

The Government of Kosovo with the assistance provided by the World Bank has identified 18 locations for the construction of small hydropower plants. A long-standing priority of the government remains concession of Zhur Hydro power Plant and other Small Power Plants, but this project has been blocked due to the disputes over inter-boundary waters with Albania.

[52] http://www.energy-community.org/pls/portal/docs/2570177.PDF (lastly visited on 12/02/2020)

Energy Efficiency

The aim of the new Law No. 06/L-078 on Energy Efficiency (which entered into force on November 2018) is to provide the necessary legal and institutional professionals for arrangement of the energy efficiency field. The scope of this law is to promote and improve energy efficiency (EE) in Kosovo with the aim at defining EE targets and achieving these targets through implementation of EE action plans, development of energy services market and other EE measures. This Law regulates activities aiming at reducing energy intensity in the national economy and negative impact to the environment from the activities related to the energy sector. This Law transposes with the Directive 2012/27/EU of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC.

This Law provides the 2020 target in its Article 4 set by the Ministry of Economic Development as national energy efficiency target for the final energy consumption not exceeding 1556 Ktoe. The Law also introduced an energy efficiency obligation with a 0,7 % target, as well as an obligation to renovate annually 1% of central government buildings. The Ministry of Economic Development (MED) has established the Kosovo Energy Efficiency Agency (KEEA), which is in charge to implement energy efficiency policies though the evaluation of opportunities to save energy and implementation of energy efficiency measures in all sectors of energy consumption.

The Law on EE requires from the KEEA starting from April 2019 and every three years thereafter, to prepare and submit the National Energy Efficiency Action Plan (NEEAP) establishing and describing the actions to achieve the State policy objectives in the field of EE, with a view to achieving the national EE targets. Moreover, KEEA is supporting municipalities to work on development of municipal plans for energy efficiency. Starting from February 2019 and every three years, municipalities must prepare and submit to KEEA a draft Municipal EE Action Plans that shall include proposed energy efficiency policy and energy efficiency improvement measures covering all sectors operating at the municipal level.

7.6.4 Natural Gas

Market Overview

Currently there is no internal gas market in Kosovo. The Natural Gas Market in Kosovo is isolated and is not connected with natural gas networks of other countries. Moreover, Kosovo has no natural gas reserves and the development of the gas infrastructure has stalled, hindering the establishment of a natural gas market. Kosovo is not linked to any operational natural gas supply networks. A connection to natural gas supply would be an important option for introduction of natural gas in Kosovo, according to the Statement of Security of Supply for Kosovo (Electricity, Gas and Oil), July 2019, published by the Kosovo Ministry of Energy and Mines as part of obligations deriving from Article 29 of the Energy Community Treaty. Gas supplies and consumption in Kosovo is therefore limited to bottled LPG (liquefied petroleum gas).

Kosovo does not produce natural gas, nor import capacity by pipelines, except as an associated product from lignite mining at the Kosovo A thermal power plant; the quantities are quite insufficient and cannot meet domestic demand. Kosovo, with international assistance, is developing a legal and policy framework for gas supply networks.

Regulatory Overview

As part of the package of energy laws, Kosovo Law No. 05/L-082 on Natural Gas ("**Gas Law**") was adopted in order to create the perspective for development of natural gas sector and fulfilment of the obligations that Kosovo has as a full member in Energy Community Treaty. This Law establishes a legal framework for the granting of authorisations for the transmission, distribution, supply, usage and storage of natural gas. Under this Law, the responsible body for developing and implementing policies in the natural gas sector is the Ministry of Economic Development ("**MED**"). This Law is in compliance with the Directive no. 2009/73/EC on common rules of the internal European natural gas market and Regulation no. 715/2009/EC on conditions of access to natural gas transmission networks. ERO is the regulatory body responsible for, *inter alia*, issuing licences for activities in the gas market.

Regulated natural gas market activities

As there are no natural gas reserves in Kosovo, the Gas Law contains no rules or provisions regarding the exploration or exploitation of gas. The activities related to this energy source that are regulated by, pursuant to the Law on Energy, and for which the ERO issues licenses, include:

(i) transmission of natural gas (the maximum term of license is 40 years);
(ii) distribution of natural gas (the maximum term of license is 40 years);
(iii) storage of natural gas (only if over 10,000 cubic metres);the maximum term of license is 40 years;
(iv) supply of natural gas (the maximum term of license is 25 years);
(v) transit, import or export of natural gas (the term of license is from 1 to 5 years);
(vi) transmission or distribution system operation of natural gas (the maximum term is 30 years);
(vii) operation of a market for electricity or natural gas.

The ERO is permitted to only issue one license for each licensed territory in Kosovo for the distribution of natural gas, and there may be one or several licensed territories for the distribution of natural gas. The Gas Law also envisages that an energy enterprise which holds a license as a distribution system operator of natural gas may not obtain a license for any other activity in the natural gas sector.

In order to obtain a construction permit for a natural gas "distribution network", an environmental permit is required. The Ministry of Environment will examine whether an impact assessment report is required for the construction of a distribution network a construction permit shall of course also be required.

Gas Storage

Principles relating to storage of natural gas including LNG are as follows:

(i) Principle features/requirements arising from Law on Natural Gas in regard to gas storage is that each storage system operator of natural gas or LNG shall operate, maintain, develop under economic conditions secure, reliable and efficient storage facilities with due regard to environment;
(ii) Refrain from discrimination between system users particularly in favour of its related undertakings;
(iii) Provide any other storage operator with sufficient information to ensure that the storage of natural gas may take place in accordance with secure and efficient operation of the interconnected system;
(iv) To provide system user with necessary information for efficient access to the system;
(v) Principle of autonomy of storage system operator;
(vi) Principle of Confidentiality to ensure information's regarding commercial advantage.

Transportation and Infrastructure

Upstream pipelines are primarily regulated by the Gas Law. Third party access shall be regulated in a similar manner by ERO to that for transmission and distribution networks. Specific operation and ownership issues related to the upstream pipeline network is not specifically regulated but would be expected to be dealt with in more detail in secondary legislation and in accordance with obligations deriving from the Energy Community Treaty.

Access for third parties to natural gas transportation pipelines should be non-discriminatory including facilities for supplying technical service. This access shall be provided for achieving a competitive market in natural gas industry taking security and regularity of supplies capacity which is or can reasonably be made available and environmentally protected.

In accordance with this paragraph the following should be taken into account:

- the need to refuse access where there is incompatibility of technical specifications which cannot be reasonably overcome;
- the need to avoid difficulties which cannot be reasonably overcome and could prejudice the efficient, current and planned future production of hydrocarbons, including that from fields of marginal economic viability;
- the need to respect the duly substantiated reasonable needs of the owner or operator of the upstream pipeline network for the transport and processing of gas and the interests of all other users of the upstream pipeline network or relevant processing or handling facilities who may be affected; and
- the need to apply their laws and administrative procedures, in conformity with the legislation in force, for the grant of authorization for production or upstream development.

If access agreements cannot be secured, the ERO is entitled to approve rules for dispute settlement related to access or refusal to allow access to every facility set forth in this law.

Trading of Natural Gas

Energy trade, including natural gas trading, is regulated by the Athens Community Treaty as the present treaty creates a single regulatory space for trade in Network Energy that is necessary to match the geographic extent of the relevant product markets. This treaty has created a single energy market among signatory parties (the signatory parties to this treaty are the European Community Members, Albania, Bosnia and Herzegovina, Croatia, Republic of Macedonia, Montenegro, Serbia and Kosovo as UNMIK). The primary governing legislation is the Gas Law and the Law on Energy; and a licence is required for this activity.

7.6.5 Upstream and the oil marketMarket Overview

All oil products that are imported are consumed within the country. Kosovo has no domestic oil supply and no pipelines, thus there is no upstream oil market. Oil products are imported approximately 80 per cent by trucks and 20 per cent by rails. Current oil legislation obliges all petroleum product storages and sale points to possess at least 5 per cent of the storage capacity for state emergency purpose. From there mostly diesel, petrol, kerosene, and residual fuel oil (mazut) are imported. In the recent year there has been an increase of import of diesel and petrol from Greece[53] .

Regulatory Overview

The current law regulating and requiring the licensing of activities in the oil sector is the Law on Trade of Petroleum and Petroleum Products in Kosovo (Law No. 2004/5 amended by Law no. 03/L-138) for wholesale, retail, transport, storage or sale of petroleum and/or petroleum products in Kosovo.

Persons registered with the Business Registration of Kosovo with a purpose to operate in the petroleum sector or vehicle servicing, with gross annual sales not exceeding EUR 50,000 within a year, may transport, store and sell or offer to sell lubricating oil, motor oil, anti-freeze and brake fluid without a license. The relevant Ministry supervises, and is responsible for ensuring safe, regular and quality of supply of Petroleum and Petroleum Products. Strategic reserves of Petroleum and Petroleum Products are determined as intervention stocks in case of basic disasters, epidemics or technological disasters.

At present licensees holding a General Petroleum License or a Petroleum Storage License shall retain and earmark five percent (5 per cent) of their Storage capacity as a strategic reserve until the creation of material reserves of Kosovo.

[53] Statement of Security of Supply for Kosovo (Electricity, Natural Gas and Oil) – July 2019

There is a contractual relationship between the licensee and the Ministry for the purpose of dealing with the strategic reserves.

7.6.6 Forthcoming developments in the Kosovo energy sector

There are currently large investment opportunities as noted above in the energy sector, and other smaller opportunities for exploring renewable energy production (more likely wind and hydropower).

With the aim of harmonizing current legislation with provisions of the third package of EU Directives on Energy, Ministry of Economic Development is in the process of re-drafting the following draft-laws, which will be included in the 2020 Legislative Program:

1. Law on the Trade with Petroleum and Bio-fuels in order to fully be in compliance with the respective European Directives – namely the Directive 2009/28/EC for promotion of the use of bio-fuels and the Minimal Oil stock Directive 2009/119/EC.

7.7 MONTENEGRO

7.7.1 Introduction to the energy market

The energy market in Montenegro in its current state is mostly synonymous with the electricity market. Lack of appropriate infrastructure hampered development of oil and gas market. However, commencement of exploration of offshore hydrocarbons as well as prospective development of Ionian-Adriatic Pipeline as a branch of Trans-Adriatic Pipeline might change the picture.

In line with its obligation to implement the "third energy package" within its legislation, the new Energy Law (*Zakon o energetici, Official Gazette of Montenegro, No. 5/2016 and 51/2017*) was adopted on 29 December 2015 and entered into force on 28 January 2016 ("**Energy Law**"), followed by amendments in 2017.. The new elements are aimed at full implementation of the EU's third energy package.

7.7.2 Electricity

Market overview

The majority state-owned "Elektroprivreda Crne Gore AD Nikšić" ("**EPCG**") is the national power utility and its core activity is electricity generation and supply. In July 2017, former strategic partner to the Government of Montenegro, Italian company A2A, initiated the withdrawal procedure from EPCG by exercising the put option after its management contract expired on July 1, 2017. The Montenegrin energy market is, at least on paper, liberalised. All consumers are entitled to choose their supplier. However, EPCG is still practically the only retail supplier.

Montenegro has the potential to develop hydro power plants, given the abundance of rivers, as well as the potential for some new types of production such as solar and wind energy To fully develop this sector, Montenegro will need a developed/upgraded transmission and distribution network.

Regulatory overview

The most important piece of legislation in the electricity sector is the Energy Law. As mentioned above, the new Energy Law has been only recently enacted. It regulates all the relevant aspects of energy sectors, i.e. the sectors of electricity, district heating, oil and gas.

The Government, the Ministry of Economy, the Energy Regulatory Agency and other stakeholders have adopted a number of implementing regulations aimed at creating the electric energy market, most important of them being: the Transmission Grid Code (Pravila za funkcionisanje prenosnog sistema električne energije, Official Gazette of Montenegro, No. 80/2017 and 90/2017), the Distribution Grid Code (*Pravila za funkcionisanje distributivnog sistema električne energije, Official Gazette of Montenegro, No. 15/2017*), the General Terms and Conditions for Supply of Electric Energy *(Opšti uslovi za snabdijevanje električnom energijom, Official Gazette of Montenegro,* *No. 70/2016*), Market Rules (*Tržišna pravila, Official Gazette of Montenegro, No. 44/2017), Rules on Third Party Access (Pravila o pristupu treće strane prenosnoj i distributivnoj mreži, Official Gazette of Montenegro, No. 13/2007*), Decree on the Compensation for Incentivising Production of Electricity from Renewable Energy Sources and High Efficiency Cogeneration (*Uredba o naknadi za podsticanje proizvodnje električne energije iz obnovljivnih izvora i visokoefikasne kogeneracije, Official Gazette of Montenegro Nos. 33/2016, 3/2007 and 3/2019*), Decree on the Manner of Realisation and the Level ofIncentive Prices of Electricity from Renewable Energy Sources and High Efficiency Cogeneration (*Uredba o načinu ostvarivanja i visini podsticajnih cijena za električnu energiju proizvedenu iz obnovljivih izvora i visokoefikasne kogeneracije, Official Gazette of Montenegro No.3/2019*).

Regulated electricity market activities

The Energy Law prescribes the following energy activities in the electricity sector:
(a) Electricity production;
(b) Electricity transmission;
(c) Electricity distribution;
(d) Electricity supply;
(e) Electricity market operation;
(f) Energy market trading, brokerage and representation.

Energy-related activities may be performed only when the relevant licence has been obtained. The following energy activities may be performed without a licence:
(i) production of electricity for individual consumption;
(ii) production of electricity in facilities with installed capacity up to 1 MW;
(iii) management of the closed distribution system;
(iv) electricity trading for the purpose of further sale, excluding the sale to the final consumer who is not responsible for balancing, agency and representation on the energy market.

The Energy Law allows for the issuance of a licence to foreign suppliers with a registered seat in the European Union, or in the member state of Energy Community, pursuant to an issued approval by the competent authority of the country where the supplier's seat is registered.

Energy activities of public interest in the electricity sector are:
(a) The production of electricity;
(b) The transmission of electricity;
(c) The distribution of electricity;
(d) The organisation of the electricity market;
(e) Trading with electricity for supply of electricity as a public service;
(f) Any supply of electricity that represents a public service.

Activities under (e) may be performed only by the public electricity supplier. EPCG has been designated by the Government of Montenegro as the public supplier.
The following activities in the electricity sector are carried out as public services obligation in order to ensure a regular, safe, reliable and quality energy supply at reasonable prices:
(i) Electricity transmission;
(ii) Electricity distribution;
(iii) The supply of electricity, in certain cases (supplier of last resort and vulnerable consumers);
(iv) Electricity market operation.

The provision of public services in the electricity sector must be on a non-discriminatory basis, transparent and under controlled prices. Energy activities which are not performed as public services are carried out in accordance with market principles.

Generation

The new Energy Law introduced a provision which restricts the obligation to obtain an energy permit only to those production facilities with up to 1 MW of installed capacity. Larger production facilities do not need an energy permit. An energy permit is also not required in the event that the production facility is being constructed in connection with a public tender. Nothing else has been recently changed in the regulatory view of the production facilities.

Trading and supply of electricity

As previously mentioned above, electricity trading for the purpose of further sale, with the exception of sale to final customers, agency and representation on the energy market does not require an energy licence. According to the Energy Law, all consumers are entitled to choose their supplier. REA is authorised to determine the regulated tariffs applied by the supplier of last resort for supply of electricity. in 2016, EPCG spun-off the distribution activity into a separate entity Montenegrin Electricity Distribution System or CEDIS.

According to the Energy Law, the right to participate in the electricity market is granted to producers, suppliers, supplier of last resort and vulnerable consumers, traders, transmission system operator, distribution system operator and self-supplying purchasers.Overall, no further changes have been made to the trading and supply of electricity.

Transmission and grid access

Access to the transmission/distribution system may be granted only to a participant licenced for performing electrical energy activity in the Montenegrin electricity market. Pursuant to Article 133 of Energy Law, TSO is obliged to enable third party access to the transmission system on a non-discriminatory basis, within its transmission capacities and in accordance with technical rules. The access may be denied or restricted only on technical grounds in the event of lack of capacity or danger to public services in the electricity sector. The dissatisfied party has the right to appeal to REA.

7.7.3 Renewable energy

Pursuant to the previous Energy Law, REA has adopted the Rules on Third Party Access to the Transmission and Distribution Network (*Pravila o pristupu treće strane prenosnoj i distributivnoj mreži, Official Gazette of Montenegro, No. 13/2007*) ("**Rules on Third Party Access**"), which further elaborate the principles and procedure for third party access.

There have been no other changes noted on the regulation of the transmission/distribution and grid access.

Market overview

At the end of 2014, Montenegro has adopted the National Renewable Energy Action Plan and has set the goal for gross final energy consumption from renewable sources by 2020 at 33 per cent, in accordance with the decision of the 10th Ministerial Council of the Energy Community. The competent Ministry monitors the implementation of the action plan for the use of energy from renewable sources. Every two years it submits a report to the Government on its progress. The Energy Law prescribes what constitutes a renewable energy source. According to the current definition, renewable energy sources include non-fossil energy sources such as: water streams, biomass, biogas, wind, solar power, landfill gas, geothermal sources, waves, tidal power, solid waste from wastewater treatment and solid communal waste. In comparison to the non-exclusive list from the previous law, the new Energy Law has omitted biofuel while further expanding the definition to encompass waste and landfill gas.

Support schemes

(a) General

The Energy Law generally facilitates the exploitation of the renewables and high efficiency cogeneration with the promotional and incentive measures. The Energy Law prescribes a list of the incentive measures for renewable energy production of electricity which includes:

1. mandatory purchase of electricity via long-term power purchase agreement (PPA);
2. feed-in tariff;
3. incentive period (period of validity for mandatory purchase);
4. exemption from payment of balancing costs;
5. priority dispatching.

In December 2018, the Government of Montenegro adopted the Decree on the Manner of Realisation and the Level of Incentive Prices of Electricity from Renewable Energy Sources and High Efficiency Cogeneration (*Uredba o načinu ostvarivanja i visini podsticajnih cijena za električnu energiju proizvedenu iz obnovljivih izvora i visokoefikasne kogeneracije, Official Gazette of Montenegro No. 3/2019*) with the effect to start gradually reducing feed-in tariffs for renewable energy sources as of January 1, 2020. The Government announced it will continue to promote the construction of wind farms, solar power plants, and large hydropower plants without guaranteed incentive prices.

Pursuant to the Energy Law, the Government has adopted the Decree on Acquiring the Status and Exercise of Privileged Producer's Rights (*Uredba o načinu sticanja statusa i ostvarivanja prava povlašćenog proizvođača električne energije, Official Gazette of Montenegro, No. 059/2016*) which prescribes the conditions and the procedure for acquiring the status of privileged producer and provisional privileged producer.

(b) Feed-in tariff

Pursuant to the Decree on the Manner of Realisation and the Level of Incentive Prices for Electricity from Renewable Energy Sources and High Efficiency Cogeneration (U*redba o načinu ostvarivanja i visini podsticajnih cijena za električnu energiju proizvedenu iz obnovljivih izvora i visokoefikasne kogeneracije, Official Gazette of Montenegro No. 003/2019* ("**Methodology**") a feed-in tariff regime has been instituted for small HPPs, wind generators, solid biomass power plants, on-roof solar plants, solid landfill waste incineration plants, landfill gas plants and biogas plants.

The right to receive feed-in tariff may be realized if the following conditions are fulfilled: (i) the power plant uses renewable energy source thereby contributing to the fulfilment of the national renewable energy target in accordance with the national renewable energy action plan; (ii) the high efficiency cogeneration facility is within the capacity envisaged by the programme for the development and usage of high efficiency cogeneration; and (iii) the power plant has acquired the status of privileged producer from the REA.

(c) Certificates of origin

The Energy Law also stipulates the issuance of certificates of origin by REA at the request of the electricity producer from renewable energy sources. A certificate of origin is an electronic document which has the sole purpose for a supplier of proving to the end customer that a certain share or quantity of energy was produced from renewable sources.

The request for issuing a certificate of origin may be filed within six months from the last day of the production period for which the issuance of a certificate of origin is requested, and at the latest by 15th of March of the current year for the production from the previous year. The request should contain information on the producer, production facility, type of primary energy being produced, data on the support schemes applicable to the facility and, in case of high efficiency generation, additional data on the minimum calorific value of the fuel, its consumption and savings of primary energy.

The first request is accompanied by a connection agreement, main design of the energy facility and a schematic overview of the measuring points. Certificates of origin are generally transferable. The certificate of origin can be transferred independently of the produced electricity to which it relates. In order to ensure that it is displayed to the customer only once, it is not allowed to compute and display the electricity produced from renewable sources multiple times.

7.7.4 Natural gas

Market overview

The natural gas market in Montenegro has a marginal influence on the overall energy market. Montenegro does not have any natural gas infrastructure and thus there is no access to any international gas transportation system. On the other hand, there is no domestic natural gas generation. Certain exploration projects reveal indications of natural gas reserves in the coastal area.

Regulatory overview

Besides the Energy Law, the following laws also govern the natural gas sector in Montenegro:

(a) Law on Mining (*Zakon o rudarstvu*, Official Gazette of Montenegro, No. 65/2008, 74/2010 and 40/2011);

(b) Law on Hydrocarbon Exploration and Exploitation (*Zakon o istraživanju i proizvodnji ugljovodonika*, Official Gazette of Montenegro, No. 41/10, 40/2011 and 62/2013);

(c) Law on Spatial Planning and Construction of Buildings (*Zakon o planiranju prostora i izgradnju objekata*, Official Gazette of Montenegro, No. 64/2017, 44/2018, 63/2018 and 11/2018).

Regulated natural gas market activities

The Energy Law regulates the following licenced activities: (i) storage of gas; (ii) transportation; (iii) distribution; (iv) supply; (v) organisation and management of the gas market; (vi) transportation and storage of liquid natural gas ("LNG"); and (vii) managing the liquid petroleum gas ("LPG") facilities. Any entity wishing to perform any of the natural gas activities has to be a local entity registered with the Montenegrin Commercial Register and has to apply for a licence to be issued by REA as the main regulatory body in the gas sector. As the case is with the electricity sector, the Energy Law prescribes that a supplier with a registered seat in the member state of the EU or the member state of the Energy Community may acquire a licence for supply of gas in Montenegro, pursuant to the corresponding approval of the competent authority in the home country. The Energy Law provides for the possibility of suspending a licence, upon request of the interested entity. REA is also entitled to cancel the licence: (i) upon the request of an energy entity; (ii) in the event of cessation of carrying out the energy activity; (iii) failure to correct irregularities in time determined by the REA; or (iv) non-compliance with orders from the energy inspectorate. REA may also temporarily cancel a licence if the energy entity does not fulfil specific conditions for a particular gas activity, does not maintain gas facilities properly, and does not determine prices in accordance with relevant methodologies adopted by REA, etc. REA will leave an additional remedy period, no longer than two months, for compliance and shall cancel the licence permanently should the energy undertaking fail to remedy the breach.

Exploration and production

The exploration and production of natural gas and other hydrocarbons in Montenegro is regulated by the Law on Hydrocarbon Exploration and Exploitation (*Zakon o istraživanju i proizvodnji ugljovodonika*, Official Gazette of Montenegro, No. 41/10, 40/2011 and 62/2013) ("Hydrocarbons Law").

According to that piece of legislation, natural gas may be explored and produced only on the basis of concessions awarded by the Government through concluding a concession agreement on gas exploration or a concession agreement on gas exploitation and exploration. This law lays down the conditions, manner and procedure for research and production of hydrocarbons and regulates a number of other related issues. The Hydrocarbons Law excludes the application of other laws potentially applicable to exploration and production of carbons, such as the general Concessions Law, the Law on Mining and the Law on Geological Exploration. The activities of research and production of hydrocarbons may be performed only with a concession awarded by the Government of Montenegro (for research) or the Parliament (for production) in accordance with the Hydrocarbons Law.

The Ministry is in charge of all legal, administrative and technical issues related to the application of the Hydrocarbons Law. The Hydrocarbons Law foresees two types of concession: for exploration and for production of hydrocarbons. However, the concession for production may also cover an exploration phase.

Interested bidders are provided with tender documents comprising the instructions for the preparation of bids, including on the content of bids and the manner of bid submission as well as other information of relevance for the award of concession. The Hydrocarbons Law specifies that one of the mandatory elements of the bid is a proposal of a working programme.

The Tender commission, formed by the Ministry, prepares the ranking list which is delivered to the Ministry and then published on the Ministry's website. The bidders are allowed to review the documents in the period of eight days and submit an appeal within an additional eight days deadline. The Ministry is required to reach a decision on the appeal within eight days as of submission of the appeal. The Ministry then submits to the Government a detailed report, the ranking list and the proposal of the concession contract (*predlog ugovora o koncesiji*).

The decision on the award of concession for exploration is issued by the Government, whereas in the event of a concession for production - the decision is issued by the Parliament upon the Government's proposal. A concession for exploration assumes the right of the concessionaire to perform geological, geophysical or other detailed analysis, in order to determine tectonic and structural features of the land or seabed and evaluate existence of hydrocarbons.

The exploration concession is awarded by the Government of Montenegro for a period of up to two years. Within six months following the end of the research works, envisaged by the working programme, the concessionaire is obliged to deliver a report containing research results. The mandatory content of this report is supposed to be prescribed by the Ministry.

A production concession allows the concessionaire to produce hydrocarbons in accordance with the law.

The main features of the concession arrangement:

(a) The surface area of the production field is determined by the concession contract and the maximum surface area is 150km2; exceptionally, it may be increased to 300km². Any surplus surface area should be returned to the grantor once the production phase starts.
(b) The Law prescribes two types of fees: (i) area fee, payable on the annual level based on the surface area covered by the concession and amounts to EUR 300 per 1km² (increased tenfold in the case of extension of the exploration phase) and (ii) royalty fee, determined as a percentage of the quantity of gas produced by the concessionaire and amounting to two per cent of the produced quantity of gas at the point of extraction. The amounts, manner of calculation and payment of these fees is further regulated by the Decree on the Manner of Calculation and Payment of the Fee for Production of Oil and Gas (*Uredba o načinu obračuna i plaćanja naknade za proizvodnju nafte i gasa*, Official Gazette of Montenegro, No. 13/14).
(c) A special corporate income tax is payable by the concession company. In 2014, the Law on Hydrocarbons Tax (Zakon o porezu na ugljovodonike Official Gazette of Montenegro, Nos. 31/14 and 52/2016) was adopted. This law applies to the upstream activities carried out within the country. The tax base is considered as the difference between the revenues and the costs recognized by Law on Hydrocarbons Tax. The tax rate is equal to 54 per cent of the tax base. The tax is paid quarterly in advance.
(d) The concessionaire is obliged to incorporate a Montenegrin company to pursue the concession project.
(e) The concessionaire is obliged to allow third party access to the facilities and the upstream network for joint use provided that it does not interfere with the regular operations of the concessionaire and other entities who already acquired the access right. The manner and conditions of access are supposed to be regulated in detail by implementing bylaws to be adopted by the Ministry.
(f) If a well is located on territory belonging to two concessionaires, the grantor may request the concessionaires to propose a programme of joint development and production.

(g) The Hydrocarbons Law prescribes detailed obligations of the concessionaire regarding the protection of the environment, safety of production, revitalization of the affected environment and the plan for conservation of the well and removal of the equipment following the completion of production phase.

(h) The concessionaire is obliged to procure insurance for the duration of the concession contract in accordance with the best international practice in this industry and provide evidence thereof to the grantor. The Hydrocarbons Law prescribes for the obligation of the concessionaire to indemnify the grantor and third parties for all the damages incurred as a result of concessionaire's actions during the concession agreement. The concessionaire is specifically obliged to compensate all environmental damages caused in the course of execution of the concession contract for production.

(i) Engagement of the contractor and subcontractors is subject to the Ministry's approval.

(j) The Hydrocarbons Law specifically prescribes the grantor's right to impose the mandatory purchase of part or all of the oil and gas produced, at a price equal to the international market price for that quantity and quality.

(k) If the concessionaire is a consortium, each member is jointly and severally liable for all the obligations arising from or in connection with the concession agreement.

(l) A pledge or mortgage over the assets obtained under the concession contract or over production facilities is possible only with the grantor's approval.

(m) Disposal of stakes or other ownership interest in the project company as well as disposal of ownership or other rights of the concessionaire may be performed only with the grantor's approval.

Transmission and access to the system

(a) General
Since gas infrastructure is rather undeveloped, there is no gas transportation system in Montenegro for the time being. Nevertheless, the Energy Law sets out rules for the potential future gas transmission systems.

(b) Access to the gas transmission system
A gas transmission system operator ("**GTSO**") is obliged to provide access to the gas transmission system ("**GTS**") to all customers based on non-discriminatory principles. The Government appointed state-owned "Montenegro Bonus" to act as the operator of the gas transmission system.

Storage

Since Montenegro still does not have any significant gas storage facilities, the storage sector appears under-regulated. Owner of the gas storage facility acts as a system operator for the gas storage subject to a licence issued by the REA. The rules applicable to the GTSO access apply *mutatis mutandis* to gas storage and access to gas storage.

7.7.5 Upstream and the oil market

Market overview

Currently there are no oil exploitation capacities in Montenegro. However, years of undersea exploration have indicated that there are significant reserves of oil and gas on the seabed near the Montenegrin coast. The Government of Montenegro has launched a tender for the award of concession for further exploration and exploitation of hydrocarbons (oil and gas).

Regulatory overview

Similarly to the natural gas sector, the oil sector is governed by the Energy Law as well as the Law on Mining, the Law on Hydrocarbon Exploration and Exploitation, the Law on Hydrocarbons Tax and the Law on Spatial Planning and the Construction of Buildings.

Regulated oil market activities

The Energy Law regulates the following licenced activities: (i) oil transportation; (ii) transport of petroleum products; (iii) wholesale trading; (iv) retail trading; and (v) storage of oil and petroleum products. Any entity wishing to perform any of the oil activities must be a local entity registered with the Montenegrin Commercial Register and must apply for a licence to be issued by REA as the main regulatory body in the oil sector. The licences are issued for a period of up to 10 years with a possibility of renewal. The Energy Law provides for the possibility of suspending a licence, upon request of the interested entity. The REA is also entitled to cancel the licence: (i) upon the request of an energy undertaking; (ii) in the event of cessation of carrying out the energy activit; (iii) failure to correct irregularities in time determined by REA; or (iv) non-compliance with orders from the energy inspectorate. The REA may also temporarily cancel a licence if the energy undertaking does not fulfil specific conditions for a particular oil activity, does not maintain gas facilities properly and does not determine prices in accordance with methodologies adopted by REA, etc. The REA will leave an additional remedy period, not longer than two months, for compliance and is to cancel the licence permanently should the energy undertaking fail to remedy the breach.

Exploration and production

The Hydrocarbons Law governs the exploration and exploitation of oil and all the abovementioned with regards to the exploration and exploitation of natural gas also applies to the exploration and exploitation of oil. However, the royalty fee is determined and paid on the basis of the quantity of oil/gas extracted and the prevailing market price and the percentage rate is progressive.

7.7.6 Impact of the coronavirus pandemic on the energy and infrastructure[54]

Montenegro enacted a number of measures with the aim of containing the spread of Covid-19. These measures include the closure of borders, ban on public transportation, police curfew, ban on public gatherings. The measures of the Montenegrin government, as well as the measures of other governments enacted in response to Covid-19, will have a dramatic effect on the tourism-dependent Montenegrin economy.

A. Covid-19 Response Investment and Support Initiative – General

I. Stimulus package

Montenegrin PM announced the details of the stimulus package on 10 April 2020 – the package has not yet been formally adopted. Below is a summary of the proposed set of support measures:

- subsidies in the amount equal to 70% of the minimum wage and 100% of taxes and contributions to the minimum wage for each registered employee in sectors that had to be closed due to measures taken to fight the epidemic, for April and May;
- subsidies for the affected businesses for April and May in the amount equal to 50% of the gross minimum wage for each registered employee in those business sectors who are at risk as a result of the measures to fight the epidemic;
- subsidy for wages of employees on paid leave for April and May in the amount equal to 70% of gross minimum wage for each employee who had to stay home to care for a child under 11;
- subsidies for wages of quarantined or isolated employees for April and May 2020 in the amount of 70% of the gross minimum wage;
- subsidies for new employment in the amount of 70% of the gross minimum wage for at least six months for entrepreneurs, micro, small and medium-sized companies, who register new employees in April and who were previously registered as unemployed with the Montenegrin Employment Agency;
- subsidies that the Government grants in this way, through support to the economy and citizens are exempt from forced collection;
- Investment and Development Fund will set-up new credit lines in a manner that complements these Government measures.
- State, state administration, and other

[54] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

entities exercising public authority, founded by the state, as well as companies with majority state-owned capital will postpone enforcement, for a period of 60 days, against the entities whose operations were prohibited by the Ministry of Health, in order to combat the epidemic;
- Each VAT refund requested will be realised within a maximum of 45 days and the Customs Administration will extend the limit of exposure of the customs guarantee for deferred payment of customs debt from 30 to 60 days for the months of April and May, for companies whose operations were prohibited by the Ministry of Health.

The stimulus package will also include support for the agriculture and fisheries sector: one-time assistance to commercial fishermen; payment of contributions to insured persons on the basis of agriculture; one-time support for beneficiaries of the nursing allowances; support for the purchase of local products; support for payment of products to domestic producers within 15 days; favourable loans for the purchase of working capital and payment of interest to the beneficiaries of these loans in the grace period; prepayment of 80% of individual premiums.

Finally, the Government will provide one-time assistance in the amount of EUR 50 to all unemployed persons registered as unemployed with the Montenegrin Employment Agency, otherwise not receiving an incentive.

II. Other financial measures and relief

Most importantly, the borrowers (both businesses and natural persons) are entitled to a 90-day moratorium on loan/financial leasing repayments.

Montenegrin Central Bank enacted prohibition to the banks to pay dividends to its shareholders, except in the form of treasury shares. The measure applies until revoked. Additionally, banks are allowed to increase exposures to a single entity or a group of related entities beyond the statutory limits of 25% of the bank's own funds, with the Central Bank's prior approval.

The Investment-Development Fund offers working capital loans to companies in the sector of medical supplies, tourism and hospitality, and food processing, up to EUR 3 million per borrower. The Government also introduced a moratorium on rent payments to the state as a lessor. The state will make advance payments on capital investment projects against bank guarantee. The deadline for submission of financial statements and tax returns has been extended until 15 April 2020 and the deadline for submission of income tax returns for natural persons has been extended until 15 May 2020.

B. Impact on the Energy and Infrastructure Sectors

There are no major developments in the energy sector as a result of Covid-19, although certain measures do affect the energy companies. Most importantly, energy entities will exempt the companies whose operations were prohibited by the Ministry of Health from paying a fixed part of the electricity bill for the months of April, May and June. In parallel, EPCG, the Montenegrin incumbent power utility will double the amount of subsidies for electricity bills, for the duration of the measures to socially disadvantaged households.

In the transport sector, transport of goods is not banned, but special health and sanitary measures are taken at the borders. International airports in Podgorica and Tivat are closed for commercial traffic and any exception has to be cleared by the National Coordination Authority. In the construction sector construction sites remain open, however, a set of measures have been imposed on employers to keep the safety of the employees and minimise the risks of spreading the disease.

The ban on the public procurement procedures (except the urgent ones and the ones in the health sector) will obviously have a negative impact on public sector infrastructure investments in this period.

7.8 NORTH MACEDONIA

7.8.1 Introduction to the energy market

The adoption of the new Energy Law in May 2018 is a big turning point in the transposition of the Third Energy Package. The law was published in the Official Gazette no. 96/2018 and entered into force on 4 June 2018. North Macedonia is a signatory to the Energy Charter Treaty and Energy Community Treaty, which further harmonises its energy legislation with the EU *acquis communautaire* with regards to the energy sector, environment, competitiveness, renewable sources of energy, energy efficiency and oil reserves. North Macedonia has also signed and ratified the UN Framework Convention on Climate Change and the Kyoto Protocol, as a non-Annex I country. With this status it may use the Clean Development Mechanism for attracting foreign investments in projects for the reduction of greenhouse gas emissions.

Still, as a candidate country for EU membership, North Macedonia needs to further develop its legislation, especially by adopting secondary legislation and provide that the implementation process is completed. The most pressing issues concern the unbundling of the transmission system operators, market opening, price regulation and balancing.

The liberalisation of the electricity and natural gas energy markets started on 01 April 2014. According to the new Law on Energy, the electricity market is completely liberalized, thus all consumers of electricity have acquired the right to choose a supplier of electricity on the free market, whereas the natural gas market is liberalized since 01.01.2015.

Regulatory overview: Energy Regulatory and Water Services Commission

For the purpose of securing efficient, competitive and uninterruptable operation of energy markets, the Energy Regulatory Commission and Water Services of North Macedonia ("**ERC**") was set up as an independent legal entity, authorised to regulate matters pertaining to energy activities performance stipulated under the Energy Law. It is composed of seven members, elected by the Parliament of the North Macedonia, after nominations by the Government. It has specific duties and obligations, as well as rights and authorities on the energy market related to the energy market participants regarding the implementation of legally stipulated obligations of the entities, which perform regulated energy activities, in the aims of guaranteeing the reliability of electricity, natural gas, renewable energy and heating energy supply.

The ERC passes bylaws (regulations, decisions, resolutions), approves documents (plans, programs) of the market participants, monitors the functioning of the energy markets, resolves disputes among performers of the regulated energy activities and consumers, adopts methodologies and tariffs for the services of the regulated energy activities and tariff systems for energy sale and passes decisions on the tariffs and the prices. The ERC issues all licences for the performance of energy activities.

The Energy Law regulates the manner of financing of the ERC by determining that, in addition to the payment for the issued licences, a certain annual amount of the profit made by the licence holders shall be paid to the ERC but no more than 0.1 per cent of the total revenue. By means of tariff-setting regulations and methodologies for services provided as regulated energy activities, the ERC stipulates the manner of calculation, approval and control of revenue generation from the performance of regulated energy activities. Electricity and natural gas price-setting regulations for consumers supplied by the supplier of last resort and the means by which the ERC sets out the manner of determination, approval and control of electricity and natural gas end prices to be paid by consumers. These shall include electricity or natural gas generation or purchase price, relevant tariff on use of energy systems and markets, balancing costs, supply charge, as well as financial and other forms of reimbursements awarded for the purpose of implementing the obligations on public service provision. Price setting regulation and methodology for oil derivatives and fuels for transport are the means by which the ERC stipulates the manner of setting, approval and control of refinery and retail prices for petrol, diesel fuels, light fuel oil and heavy oil (mazut), as well as retail prices for blends of fossil fuels and biofuels for transport.

Energy Agency

The Energy Agency has been established to support the implementation of the energy policy in North Macedonia. It has the capacity of a legal entity and it is independent in its work. The support in the implementation of the energy policy shall be realized by the Energy Agency through engagement in relation to: the preparation of medium and long term strategies and development plans; the preparation of long and short term programs for energy efficiency and use of renewable energy resources, the preparation and coordination of activities for the implementation of investment projects, regional cooperation and coordination of regional projects, drafting bills, by-laws and technical regulations proposals, in the field of energy, and performing other activities in the field of energy, as determined by the Energy Law. The Energy law stipulates a few additional competences of the Energy Agency in the area of renewables.

7.8.2 Electricity

Market overview

The main functions of the electricity system of North Macedonia are the generation, supply, transmission and distribution of electric energy. Participants in the electricity markets are the electricity generators, electricity transmission system operator, electricity distribution system operator, electricity market operator, suppliers and traders with electricity and the consumers. Each has certain rights and obligations, as well as stipulated conditions on undertaking activities and use of the electricity system. The process of restructuring the Electric Power Company of Macedonia ("ESM") commenced in 2004 and was completed in September 2005. As part of the Government's programme to liberalise the electricity market, the restructuring resulted in the unbundling of the vertically integrated ESM into four legally separate enterprises. The Electricity (Transmission) System Operator ("MEPSO") is a state-owned joint-stock company and is controlled by the Government and is responsible for transmitting electricity and managing the high voltage transmission network, operating the electricity central dispatching system and implementing market operations. Electricity generation is performed by JSC Electric Power Plants of North Macedonia ("ESM"), a state-owned joint-stock company, and JSC TPP Negotino – a thermal power plant also owned by the Government. EVN AD Makedonija, a joint stock company, performs distribution and retail supply for tariff consumers and was privatised in 2006 through a sale of 90 per cent of its shares to the Austrian company EVN AG. Distribution is also performed by AD ESM Skopje – Branch Office Energetics.

As stated above, the electricity market is now completely liberalized. The market of electricity consists of two segments, a regulated and an unregulated electricity market. In 2018 in the regulated electricity market, the purchase and sale of electricity was conducted at prices and conditions approved by the ERC. On the unregulated electricity market, the sale of the electricity is performed at prices and conditions that are free agreed between the buyer and the seller, at their own choice, risk and expense. The percentage of the actual liberalization of the electricity market in 2018 was 47.26%. The percentage of liberalization compared to 2017 (39.75%) has been increased due to the increase in consumption made by consumers connected to the transmission network, as well as reducing the consumption of tariff consumers as a result of the exit of a significant group of small consumers in the electricity free market.

Regulatory overview

In accordance with the Energy Law, the following energy activities in the electricity market are regarded as regulated energy activities:

(a) electricity transmission;
(b) electricity market organisation and operation;
(c) electricity distribution;
(d) electricity supply of last resort; and
(e) electricity generation for the needs of the electricity supplier of last resort.

The performers of the energy activities cannot start performing the activity without obtaining licence from the ERC. The licence is valid for a period of no less than three years and no more than 35 years. The same validity period of a license applies to all types of licensed activities in the energy sector. Entities which perform regulated energy activities are required to comply with the obligations of the provision of a public service. The Government of North Macedonia, upon previously obtained opinion from the ERC and opinion or decision of the Commission for Protection of Competition, may issue a decision by which a company that performs an energy activity, and it is not a regulated energy activity, has an obligation to provide a public service in a specified time period. The ERC shall specify the conditions and manner for fulfilling the public service obligation in the license that it issues to the performer of the energy activity. The obligations additional obligations for providing a public service, imposed by the ERC must be clearly stipulated, easily verifiable and non-discriminatory.

A branch office of a foreign entity organized in North Macedonia whose founder has been issued a license for performing trade or supply of electricity or natural gas in a state that is a contracting party or participant in the Energy Community Treaty may, by applying the principle of reciprocity, to perform these activities in North Macedonia once a decision is made for entry in the register of foreign traders and suppliers of electricity and natural gas, run by the ERC.

The services provided by entities performing regulated energy activities should secure reliable, high-quality and uninterrupted energy and energy fuel delivery to consumers, under equal terms and conditions, prices and tariffs, taking into due consideration the need for energy efficiency improvements and environmental protection and promotion.

Generation

The electricity generator may sell the generated electricity and / or system services on the electricity market in North Macedonia and abroad. The electricity generator has the following obligations:

- offers system services to the electricity transmission system operator for balancing the system,
- ensures the availability of agreed quantities of electricity and / or system services to the point of receipt in the electricity transmission or distribution system,
- has to be equipped with all necessary technical resources,
- submits reports, data and information to the operator of the electricity transmission system or the operator of the electrical distribution system, and
- submits to the electricity transmission system operator and the electricity market operator data and information from the contracts for the purchase and sale of electricity, the availability of the production capacity and / or the system services, except business financial data.

In order to ensure security of electricity supply, the Government may adopt a decision by which it imposes an obligation on the electricity generator to provide a public service. The generator needs, at any time, to have operational reserves of primary fuel in an amount that is required for at least 15 days of work with maximum capacity.

The construction of new facilities or expansion of existing facilities for electricity generation, combined production of electricity and heat or facilities for the production of heat energy is based on obtaining authorization from the competent authorities. Such authorization is not required if:

1. the new generation energy facility has a total installed electric and / or thermal power of less than or equal to 10 MW;
2. with the expansion of the production energy facility, the total installed electrical and / or

thermal power of the object is less than or equal to 10 MW or

3. the energy produced in the energy facility will be used exclusively for its own needs.

The procedure can be initiated by interested domestic and foreign investors, by submit a request for issuing an authorization to the Government, i.e. the local municipality. The Government, upon a proposal of the Minister, i.e., the council of the local self-government unit, upon a proposal of the mayor, decides within 60 days from the day of receiving the completed request. The authorization is valid three years from the day of its entry into force, and it will cease to be valid if the authorization holder has not been able to provide building permit for the facility within this deadline.

Trading and supply of electricity

The electricity trader may purchase electricity in the country and from abroad, for the purpose of selling it to other traders, suppliers, the electricity transmission system operator and electricity distribution system operators, as well as for the purpose of selling it to consumers abroad. The electricity trader in the role of supplier can sell electricity to consumers which meet the requirements for independent participation on the electricity market. They must also submit information to the electricity market operator and electricity transmission system operator regarding the electricity quantities and relevant time schedules relating to all electricity purchase / sale contracts, as well as related to contracts on cross-border transactions through the transmission grid. An electricity trader when performing cross-border electricity transactions must provide sufficient interconnection transmission capacity and/or distribution capacity and regulated services, pursuant to the relevant bylaws (Electricity Market Code, Transmission and/or Distribution Grid Code, Rules on Awarding Cross-Border Transmission Capacity) for the electricity it has undertaken to deliver to its consumers.

The electricity supplier purchases electricity in the country and from abroad, for the purpose of selling it to consumers, traders, other suppliers, the electricity transmission system operator or the electricity distribution system operators, as well as to consumers abroad. For the electricity it has committed to deliver to its consumers, the electricity supplier must secure the necessary transmission and/or distribution capacity from the relevant operators, pursuant to the applicable tariffs, Electricity Market Code, Transmission and Distribution Grid Codes.

The electricity supplier shall invoice the consumers for the electricity delivered under the agreed price and the electricity market use charge. When the supplier has signed a contract with the electricity distribution system operator on charging the distribution costs, the electricity supplier shall also invoice the consumers for the transmission and/or distribution system charges. The invoices shall be issued on the basis of active and/or reactive electricity consumed and engaged power, as metered by the relevant system operator.

The electricity supplier of last resort purchases electricity to address the demands of consumers who have not been supplied with electricity. If the consumer is a household or a small consumer, their supply is carried out by the universal supplier. The purchase prices and relevant contracts with the generator are approved by the ERC.

Transmission

The electricity transmission system operator shall maintain, upgrade and expand the transmission grid, operate the electricity transmission system of North Macedonia and secure connection of the transmission system to the transmission systems in the neighbouring countries. The operator of the electricity transmission system is a company that:

1. as a legal successor of the Electric Power Company of Macedonia is the owner of the electricity transmission network consisting of substations, line infrastructure objects - transmission lines, plants, facilities and assets that are in function of performing the

energy activity transmission of electricity and management of the electrical energy transmission system;
2. is not part of a vertically integrated company;
3. is holder of a license for performing the energy activity electricity transmission;
4. it does not perform and is independent of the performance of other activities in the power sector determined by this Law; and
5. is certified and appointed for the electricity transmission system operator by the ERC.

In order to ensure the independence of the electricity transmission system operator, the same person or persons are not entitled at the same time:

- to participate, directly or indirectly, in the management of a company that carries out some of the electricity generation and / or supply activities and at the same time directly or indirectly manage or exercise another right in the electricity transmission system operator;
- directly or indirectly participate in the management and management of the electricity transmission system operator and at the same time directly or indirectly manage or exercise another right in a company that carries out any of the electricity generation or supply activities and
- to appoint members of the supervisory body, managing authority of the electricity transmission system operator and at the same time directly or indirectly to manage or exercise another right in a company that carries out some of the activities of generation and / or supply of electricity.

In order to cover losses in the electricity transmission system, electricity is purchased under market terms and conditions and in a transparent, non-discriminatory and competitive manner. Also, ancillary services and the relevant operational reserve are purchased under market terms and conditions and in a transparent, non-discriminatory and competitive manner, pursuant to the Electricity Market Code.

The electricity transmission system operator is required to adopt and publish the Rules on Interconnection Transmission Capacity Awarding, as well as the Electricity Transmission Code. The ENTSO-E network rules are applied directly by the operator of the electricity transmission system.

The electricity transmission system operator is obliged, *inter alia*, to connect generators, consumers and distribution system operators to the transmission grid, as well as to allow third party access for electricity transmission system use, pursuant to the present law and the Transmission Grid Code. Based on the principles of objectivity, transparency and non-discrimination, new interconnection capacities with neighbouring countries are required to be constructed, taking due consideration of the efficient use of existing interconnection capacities and the balance between investment costs and benefits for the consumers, to provide cross-border electricity flow through the transmission grid of North Macedonia within the available transmission capacity, as well as to develop, upgrade and maintain the transmission system, for the purpose of safe and efficient system operation.

In order to cover losses in the electricity transmission system, electricity is purchased under market terms and conditions and in a transparent, non-discriminatory and competitive manner. Also, ancillary services and the relevant operational reserve are purchased under market terms and conditions and in a transparent, non-discriminatory and competitive manner, pursuant to the Electricity Market Code. The electricity transmission system operator is required to adopt and publish the Rules on Interconnection Transmission Capacity Awarding, as well as the Electricity Transmission Code. The ENTSO-E network rules are applied directly by the operator of the electricity transmission system.

Distribution

The electricity distribution system operator is responsible for the maintenance, upgrading, expansion and operation of the distribution system used to perform its activity, and shall be obliged to secure its connection to the electricity transmission system.

The operator of the electricity distribution system or vertically integrated company that is the founder of the electricity distribution system operator on the territory of the Republic of Macedonia is the owner of the electricity distribution network consisting of substations, line infrastructure facilities - transmission lines, objects and assets in the function of performing the energy activity distribution of electricity. A company that holds a license for performing an electricity distribution activity cannot have a license and cannot participate in the performance of the activities of production, transmission, organization and management of the electricity market, trade and / or supply of electricity.

Access and connection to grids

The Energy Law sets out the obligation for the transmission and/or distribution system operators, on the basis of the published tariffs, to allow access to the relevant system to all customers, in a transparent and objective manner that prevents discrimination of system users.

The transmission and/or distribution system operators shall be obliged to allow connection to the relevant system, pursuant to the relevant Grid Code:

(a) to all electricity consumers and users of the electricity transmission system and the distribution systems on the territory of North Macedonia;
(b) to all natural gas or heating energy consumers and users of the natural gas or heating energy transmission and distribution systems on the territory where the service is provided.

The electricity transmission or distribution system operators shall provide priority access to electricity systems for the electricity generated from renewable sources, taking into due consideration the limits stemming from the possibilities in the electricity system. The relevant energy or natural gas transmission or distribution system operator shall be obliged to allow existing and new grid users access to the relevant energy transmission or distribution grid, pursuant to the relevant Grid Code and Supply Rules:

(i) in an objective, transparent and non-discriminatory manner;
(ii) based on the principles of regulated third party access; and
(iii) in accordance with prices and tariffs previously approved and published by the ERC.

The relevant energy transmission or distribution system operator can deny access to the relevant grid only in cases of electricity or natural gas transmission or distribution capacity shortage; the providing of access for a given user can jeopardize the security of energy supply in North Macedonia or; the provision of access to the appropriate system would prevent the appropriate system operator from performing its public service obligation. It shall be obliged to inform the access applicant in writing, with a detailed and unambiguous explanation of the reasons for the denial of access.

The operator of a new direct current interconnection line may request from the ERC a waiver for a certain period of time from the obligation to provide third party access to the new interconnection line if the following conditions are met:

(a) the investment increases competition and reliability in the supply of electricity;
(b) the risk associated with the investment is such that an investment cannot be realized if the exemption from the obligation to provide access to a third party is not allowed;
(c) the interconnection line for which an exemption from the third party's access obligation is required must be owned by the person who is independent, at least in its legal form, from the operator of the electricity transmission system of North Macedonia and from the operator of the power system in whose system the interconnection line will be built;
(d) the users of the interconnection line are charged for its use;
(e) as of July 1, 2007, no part of the investments or operating costs for the interconnection line can be recovered through fees for

the use of transmission or distribution system of electricity connected to the interconnection line and

(f) the exemption from the obligation to provide third party access does not affect the competition and the efficiency of the electricity market in the region, as well as the efficient operation of the regulated transmission system to which the interconnection line is connected.

The relevant energy transmission or distribution system operator, as part of the relevant Grid Code, shall be obliged to set out the connection rules for the relevant grid and the connection charge setting methodology. The connection rules shall take into due consideration the consequences caused by the connection and which affects other grid users, the connection points at plants, facilities and devices and type of installation required for grid connection.

7.8.3 Renewable Energy

Market overview

The legal framework in North Macedonia is aimed at stimulating investments in renewable energy and the greater involvement of renewable energy resources in total energy consumption and increasing energy efficiency. There are favourable conditions for the use of hydro energy, geothermal energy, solar and wind energy, as well as energy derived from biomass. With the new Energy Law of 2018 premiums were introduced as a new measure for support to electricity generators using renewable energy sources, in addition to the already existing preferential tariffs. The premium represents an additional amount of the price that the preferential producer has earned with the sale of the produced electricity. The preferential producer who use premium is selected through a tender procedure with an auction, conducted by the Ministry of Economy. The Energy Agency maintains a register of issued, transferred and revoked guarantees of origin of electricity produced from renewable energy sources, which is published on its website. The origin of the guarantee is of a standard size of 1 MWh and only one guarantee of origin is issued for each produced unit of energy.

The electricity market operator is obliged to purchase the electricity produced by preferential electricity generators using a privileged tariff. The price at which the electricity market operator sells the electricity to the suppliers and traders is calculated at the end of the month as the average price at which the electricity market operator purchased the electricity from the preferential producers of electricity using a preferential tariff.

The electricity market operator then sells the purchased electricity produced by the preferential producers to electricity suppliers and traders who sell electricity to the final consumers. Suppliers and retailers buy the quantity of electricity produced by the preferential producers from the Electricity Market Operator every day, according to the participation of the announcements for the electricity needs of their consumers in the total envisaged needs of the electricity consumers in North Macedonia.

Different types of power plants are represented in the total production of electricity from preferential generators in 2018, in the following manner:

- small hydropower plants as preferential producers are represented by 53.82%,
- wind power plants participate with 25.81%,
- thermal power plants on biogas with 14.33%,
- photovoltaic power plants with 6.04%.

Of all the renewable sources of energy in Macedonia, hydropower is used for the production of electric power, biomass is most frequently used in the form of firewood for households, and geothermal energy is mostly used for heating greenhouses. Solar thermal energy is used for heating domestic hot water.
Support schemes

The Government of North Macedonia adopted a decision on national mandatory objectives for the energy participation produced from renewable sources in the gross financial energy consumption and the energy participation produced from renewable sources in the final energy consumption in transport. This decision regulates that the national objectives which should be fulfilled until 2020, are stipulated as follows: 23% of participation of renewable energy in the final gross energy consumption and 10% participation in the transport.

The Strategy on Renewable Energy Sources sets out the policy on the use of renewable energy sources which set the targets on the use of renewable energy sources and the manners for attaining these targets.

The Government of North Macedonia also adopted an action plan on renewable energy sources in North Macedonia until 2025 with a vision until 2030 which further elaborates the specific actions and measures to be taken, in order for the goals of the Strategy on Renewable Energy Sources to be achieved.

The Energy Law has simplified the procedures for acquiring the status of preferential electricity generator by authorising the ERC to issue a decision on granting the status and maintaining the relevant registry while the Government is authorised to determine the feed-in tariff and duration. In order to stimulate investments in renewable sources, temporarily status of preferential electricity generator may be awarded if the investor has obtained the construction authorisation for the energy facility in question, or has obtained a construction permit for the energy facility, when the construction thereof does not require a construction authorisation or has signed a concession contract for the use of natural resources or has acquired the right to construction of the energy facility in an open call procedure, pursuant to the Energy law.

The Government of the North Macedonia passed an Act on Electricity Feed-In Tariffs, which stipulates, for each type of preferential generator separately, the following:

(i) the specific terms and conditions to be met by the power plant in order to obtain the status of preferential generator;
(ii) the upper threshold for the power plant installed capacity required for obtaining the status of preferential generator; and
(iii) electricity feed-in tariffs and the period for their application.

The Energy Agency issues, transfers and revokes guarantees of electricity origin from renewable sources. The guarantee of origin is a document issued by the Agency for the purpose of securing evidence for consumers that a particular energy quantity has been generated from renewable sources. The guarantees of electricity origin issued by foreign states can also be recognised if they fulfil certain conditions prescribed by law. This also represents one of the incentives applied for the purpose of promoting renewable energy sources. The guarantees of electricity origin from renewable sources issued by foreign countries shall be recognised under the terms and conditions and in a manner stipulated pursuant to the present law.

7.8.4 District Heating

Market overview

The market participants are defined by the Energy Law as generators, operator of the distribution system and district heating suppliers, following the market model for the electricity market with the necessary differences arising from the energy type in question. The municipalities, as units of the local self-government, are obliged to enable the performance of the following energy activities for the purpose of reliable, safe, uninterrupted and quality heating energy supply to the consumers on their territories:

(a) heating energy generation;
(b) heating energy distribution; and
(c) heating energy supply.

The Energy Law provides that, for installed power systems of consumers over 80 MW, one entity cannot hold licenses for production, distribution and supply of heat.

The heating energy supplier is required to provide consumers with whom it has signed contracts, with reliable, uninterrupted and quality heating energy supply, pursuant to the Heating Energy Supply Rules, the signed supply contracts and the licence issued. For all heating energy systems where it supplies consumers, the heating energy supplier is required to sign annual contracts with the heating energy distribution system operator for heating energy purchase intended to address the consumers' demand, under prices and tariffs previously approved and published by the ERC. These contracts are subject to approval by the ERC, and stipulate in detail the mutual rights and obligations of suppliers and distribution system operators, based on the Distribution Grid Code and Heating Energy Supply Rules.

Active heating systems in North Macedonia energy exists only in the territory of the City of Skopje where three systems are operating. The largest system is the one managed by BALKAN ENERGY GROUP AD Skopje on which during 2018 51,357 consumers were connected.

Regulatory overview

Under the Energy Law, the distribution of thermal energy and the regulated generation of thermal energy are regarded as regulated energy activities. The performer of the regulated energy activity - production of thermal energy, is obliged to provide a public service for the needs of the consumers and for covering the losses in the system, system reserve and system services for maintaining the necessary operating parameters within the heating system to which it is connected. A licence for the regulated heating energy generation activity is granted on the basis of an open-call procedure by the ERC. In the case of distribution systems with only one generator of thermal energy, it shall by exemption be granted a licence for regulated generation of the thermal energy.

At the request of the regulated generator, the ERC shall set the charge to be paid to the regulated generator for the services provided in the heating energy system. When setting the charge, due consideration shall be taken of the fixed and variable costs of the regulated generator, as well as the reasonable return of capital. The charge shall comprise of two portions - charge for the provision of ancillary services and system reserve and regulated price for the heating energy generated.

The ERC adopted the Price-Setting Rulebook for Heating Energy and System Services, which regulates the manner, procedure and price-setting methodology for system services and system reserve charges, the regulatory price for the heating energy generated, as well as the manner of calculating and the regulatory period for which the average price for heating energy is calculated. The licence holder for regulated heating energy generation cannot hold a licence on heating energy distribution, supply activities, heating energy generation and supply activities. The regulatory regime on the thermal energy supplier is explained in Section 4.1 (Market overview).

Generation and Distribution

Independent generators generate thermal energy as secondary products in the combined thermal electricity and regulated generators of thermal energy which, in addition to the requirement to provide public service, are obliged to provide energy to cover losses in the system, system reserve and system services. The charge of the regulated generator for the ancillary services is stipulated by the ERC. The heating energy generator shall own and operate the heating energy generation plant pursuant to the law, other regulations, grid code and the terms and conditions and criteria stipulated in the licence and shall sell the heating energy to the heating energy distribution system operator to which it is connected, under the terms and conditions stipulated in the Energy Law.

The distribution of heating energy is carried out by legal entities who are the owners of systems for the distribution of heating energy or on the basis of an agreement for PPP for the construction of a new system or an agreement for the establishment of a PPP for a public service, management, use, maintenance and expansion/upgrading of an existing system

7

for distribution of thermal energy or by public enterprises established by the local self-government units. The construction of new systems for the distribution of thermal energy in the area of a local self-government unit shall be carried out on the basis of a PPP agreement awarded by the council of the local self-government unit. This agreement also includes the right to carry out the regulated energy activity of distribution of thermal energy. The period for which the PPP agreement is granted can be no longer than 35 years. The heating distributor shall not have the right to transfer the PPP agreement to a third party without the prior written consent from the public partner.

7.8.5 Natural Gas

Market overview

After a long political turmoil, North Macedonia has made a considerable step towards transposition of the Energy Community acquis. The new Energy Law makes way for full ownership unbundling and certification of the transmission system operator. North Macedonia starting from 01.01.2015 has a fully deregulated wholesale and retail market. The distribution and transmission systems of the natural gas have the same obligations of the electricity transmission and distribution operators. The other subjects (suppliers, supplier of last resort and traders) have the same rights and obligations as in the electricity market.

In order to ensure the independence of the natural gas transmission system operator, the same person or persons are not entitled at the same time:

1) to participate directly or indirectly in the management and supervision of a company that carries out some of the natural gas production and / or supply activities and directly or indirectly manage or exercise another right with the operator of the natural gas transmission system;
2) directly or indirectly participate in the management of the natural gas transmission system operator and, at the same time, directly or indirectly manage or exercise another right in a company carrying out some of the natural gas production and / or supply activities; and
3) to appoint members of the supervisory body and the managing body of the natural gas transmission system operator and at the same time directly or indirectly manage or exercise another right in a company performing some of the natural gas production and / or supply activities.

A company that has a license for performing distribution of natural gas cannot have a license and cannot participate in the activities of natural gas transmission, organization and management of the natural gas market, natural gas trading and / or supply of natural gas. Taking into consideration the possibility of building smaller regional systems for the transmission and distribution of natural gas in the Republic, the law allows for the institutionalizing of a combined operator of transmission and distribution systems.

Where a natural gas distribution system operator is part of a vertically integrated natural gas undertaking, it must be independent in relation to its legal personality, organization, and decision-making, and to act independently of other activities that are not related to the distribution of natural gas. The independence of the natural gas distribution system operator does not include the obligation to separate ownership of the distribution system assets from the vertically integrated natural gas company.

A natural gas supplier in the last resort is obliged to supply consumers who have not been provided with a natural gas supplier in the event that:

(a) the previous supplier has terminated the fulfilment of its supply obligations under the existing supply contracts;
(b) a bankruptcy procedure has been initiated by the previous supplier with personal management, or at the request of a creditor, as well as liquidation;
(c) the license of the previous supplier has been suspended, permanently revoked or has ceased to exist; and

(d) consumers have not concluded a new contract for the supply of natural gas after the termination or expiration of the existing supply contract.

In this section of the energy market, special market rules are not allowed but they shall be a constituent part of the grid regulation for the transmission of natural gas. As in the section for electricity, the activities of transmission of natural gas and operating the natural gas system are merged, and a single licence is issued. In the event that the operators of the transmission systems do not fulfil the obligations from the development plans, the ERC may intervene as appropriate.

Regulatory overview

The ERC is the main regulatory body in the segment of natural gas energy market. It approves the Natural Gas Market Code, regulates the natural gas market organisation, the terms and conditions to be met by natural gas market participants, the manner and terms and conditions for grouping of natural gas customers and/or sellers into balancing groups for the purpose of reducing balancing costs, establishes the organisation and control of natural gas and ancillary services trading, including cross-border trading. It also regulates the methodology for setting the balancing charge and manner of charge collection, as well as financial guarantees for the liabilities of natural gas market participants related to the settlement of balancing services.

By means of price-setting regulations for natural gas for consumers supplied by the supplier of last resort, the ERC regulates the manner of setting, approving and control of electricity and natural gas end prices to be paid by consumers. This includes the electricity or natural gas generation or purchase price, relevant tariff on use of energy systems and markets, balancing costs, supply charge, as well as financial and other forms of reimbursements awarded for the purpose of implementing the obligations on public service provision. The regulated energy activities on the natural gas market are:

(a) natural gas transmission;
(b) natural gas transmission system operation;
(c) natural gas distribution;
(d) natural gas supply of last resort.

Exploration and production

According to the Strategy for Energy Development in the North Macedonia by 2030, Macedonia does not have its own natural gas deposits. Hence, the Energy Law contains no provisions regulating the production and exploration of deposits of natural gas in Macedonia.

Transmission and access to the system

The natural gas transmission system operator is a public enterprise or company owned by North Macedonia. The natural gas transmission system operator is obliged to adopt and publish a Transmission Grid Code for the system which it operates. The fees charged by the operator of the natural gas transmission system for access to the natural gas transmission system are determined on the basis of the tariffs approved by the ERC. The natural gas transmission system operator shall invoice the natural gas market participants for any deviations from the announced physical transactions, under prices calculated pursuant to the price-setting methodology for balancing services, which is an integral part of the Natural Gas Market Code. The operator of the natural gas transmission system is a company that owns a natural gas transmission system; is not part of a vertically integrated company; is the holder of a license for performing the energy activity natural gas transmission; it does not perform and is independent of the performance of other energy activities; is certified and appointed as an operator of the natural gas transmission system by the ERC. Obligations to allow third parties access to the grid are set out in the same manner as those for the operator of the electricity transmission system.

The ENTSO-G network codes are directly applicable by the natural gas transmission system operator.

Liquefied natural gas

The Energy Law contains no provisions regulating the production and exploration of deposits of liquefied natural gas in North Macedonia.

7.8.6 Forthcoming developments

The construction of new distribution systems, new natural gas transmission networks and new crude oil and oil derivatives transport facilities must be performed by legal entities on the basis of an issued authorisation. Upon proposal by the Energy Minister, the Government of North Macedonia shall adopt a decision regarding construction authorisation for new systems, networks or facilities. The construction of new natural gas distribution systems for a service area within the territory of the North Macedonia shall be performed by legal entities and on the basis of a PPP agreement awarded by the Government of North Macedonia and a concession contract for a public service assigned by the Government, by which the concessionaire undertakes to build and use and operate a new natural gas distribution system. The period for which the concession is awarded can be no longer than 35 years. The concession holder is entitled to transfer the agreement to another entity only on the basis of the prior consent of the Government of North Macedonia. New facilities planned for the expansion of the existing energy system, including the construction of new and upgraded existing connections owned by the natural gas system or network operator and anticipated by the Energy Law shall be constructed and owned by the relevant system or network operator.

7.8.7 Upstream and the oil market

Market overview

North Macedonia does not have any oil and gas deposits. North Macedonia imports all of its needs of oil and oil products. Total imported quantities of oil derivatives in North Macedonia in 2018 is 987,662 tons. Most oil products are used as final energy sources, mostly in the traffic sector.

There is one crude oil refinery in Skopje, owned by OKTA AD Skopje, which is connected to the port in Thessaloniki via the 213 km Thessalonica-Skopje pipeline. The refinery has a total capacity of 2.5 million tons annually but is currently in shut down.

The Energy Law stipulates that energy activities related to the oil market are non-regulated activities, i.e. none of the energy activities involving the transmission, storage and/or trade with crude oil and oil derivatives is regarded as an energy activity by means of which the public service is provided. Entities performing energy activities related to:

(a) crude oil processing and oil derivatives production;
(b) biofuels production;
(c) production of fuels for transport by blending fossil fuels and biofuels;
(d) transport of crude oil or oil derivatives through oil pipelines or product pipelines;
(e) storage of crude oil, oil derivatives, biofuels and fuels for transport;
(f) trading in crude oil, oil derivatives, fuels for transport and biofuels are obliged to use and maintain the facilities, devices and plants intended for performance of energy activities, pursuant to the technical regulations and standards and other regulations on reliable and safe operation and environmental protection;

Under the Energy Law any entity performing crude oil and/or oil derivatives transport through the oil pipeline and/or product pipeline activity must adopt rules governing the operation of the oil pipeline or product pipeline and publish them on its website.

Regulatory overview

The Government shall set the annual percentage share of biofuels to be achieved in the total fuels for transport quantities in North Macedonia with the EU Directive on renewable sources. The Rulebook on Liquid Fuels Quality regulates in particular: the type of liquid fuels that can be marketed, as well as their characteristics; the manner of determining the liquid fuel quality and their conformity with applicable standards and technical requirements; the manner and procedure on monitoring the liquid fuel quality; the rights and obligations of the crude oil, oil derivatives and fuels for transport market participants; the rights and obligations of market participants and state authorities in the transitional period required for the replacement of reserves of blends of fossil fuels and biofuels for transport.

By means of price-setting regulation and methodology for oil derivatives and transport fuels, the ERC regulates the manner of setting, approving and control or refinery and retail prices for petrol, diesel fuels, light fuel oil and heavy oil (mazut), as well as the retail prices for blends of fossil fuels and biofuels for transport, under which the maximum refinery and retail prices for oil derivatives and the maximum retail prices for blends of fossil fuels and biofuels are set. A decision on the maximum refinery and retail prices for oil derivatives shall be adopted by the ERC, upon a request for setting the maximum refinery prices for oil derivatives submitted by the company for crude oil processing and oil derivatives production.

7.8.8 Impact of the coronavirus pandemic on the energy and infrastructure[55]

A. Covid-19 Response Investment and Support Initiative – General

Following the declaration of a national state of emergency on 18 March 2020 by the President of the Republic of North Macedonia, which is initially set to last 30 days but can be extended, the Government has been focused on instituting measures in order to prevent the spread of Covid-19 disease since its outbreak. Such measures included closing down border crossings and airports, restricting the movement of the population and prohibiting social gathering and public events, and have caused a significant slowdown in economic activities and growth. Therefore, the Government also instituted a number of economic measures which are primarily aimed at easing payment obligations, providing tax breaks and financial support to businesses and preserving jobs.

The set of economic measures aimed at easing payment obligations include the following:

- reducing the statutory default interest rate for payment obligations of legal entities and individuals, as well as the penalty interest rate for public duties and taxes by 50%, for the duration of the state of emergency;
- disallowing any new preliminary procedures for opening a bankruptcy procedure or new bankruptcy procedures, and postponing all such procedures that have already been initiated for the duration of the state of emergency;
- suspending all procedures and actions for enforcement of claims, until 30 June 2020 (certain exemptions apply, including to claims for child support);
- Allowing banks and savings houses to offer their clients (individuals and nonfinancial legal entities), in a simplified procedure, by posting such offer on their website, without prior request from the client and without the need to conclude amending documentation, more favourable changes to the terms and conditions governing their banking products (corporate loans, consumer loans, credit card overdrafts, etc.), including an extension of loan repayment and lower interest rates. Unless individuals expressly decline such offer, it is deemed to be accepted, unless otherwise stated in the offer; while legal entities must expressly inform the banks and savings houses of their acceptance of the offer within 10 days as of its posting.

The Government instituted a separate set of economic measures aimed at helping companies, as well as sole proprietors, which are active in the sectors whose operations were most affected by implementing the preventive measures against the spread of Covid-19, namely, restaurants and other food businesses, hotels and other accommodation businesses, tourist agencies, and freight

[55] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

transport businesses. Such set of measures include:

- making available interest-free loans, through the Development Bank of North Macedonia, for micro, small and medium companies, and sole proprietors, active in the most affected sectors (mainly, in restaurants, hotels, tourist agencies, freight transport companies) in amounts: up to EUR 5,000 for enterprises with up to 10 employees, up to EUR 15,000 for enterprises with 11 to 50 employees and up to EUR 30,000 for those having 51 to 250 employees;
- giving such businesses a tax exemption from paying the amount of monthly advance payments for corporate income tax (for companies) and from personal income tax (for sole proprietors) for the months of March, April and May 2020, provided such businesses do not reduce the number of employees for a period of three months as of the end of application of the decrees by which such tax exemptions are instituted, except in case of death, retirement or termination by employees.

The tax exemptions described above can also be used by businesses in other sectors, provided they meet at least one of the following additional conditions: (i) the taxpayer's total revenues are reduced by at least 40% in the current month compared to February 2020, or the reduction in total revenue for 2020 exceeds 40% compared to the same period in 2019; or (ii) the number of employees who do not work or do not contribute to the economic activity of the taxpayer is at least 25% of the total number of employees compared to February 2020; or (iii) the taxpayer has closed at least 50% of the points of sale through which it performs its business activity.

The Government has also made available to practically all businesses in the private sector (except for, notably, private employment agencies for employees they have seconded to public sector entities) two alternative forms of direct state aid, but the use of one such form of assistance excludes the possibility to use the other. Such aid may consist of: (i) payment of the salaries of employees of the private sector employer for the months of April and May 2020 in the amount of up to MKD 14,500 (approximately EUR 235) per employee per month (the "Aid for Salaries"); or (ii) payment of 50% of the calculated contributions for mandatory social insurance of employees of the private sector employer for the months of April, May and June 2020, in the amount of 50% of such calculated contributions, but not more than 50% of the contributions for mandatory social insurance calculated on the average gross salary per employee in the country, according to the data of the State Statistical Offices form the month of January 2020 (the "Aid for Contributions"). However, employers that use the Aid for Salaries or the Aid for Contributions and generate profit at the end of 2020 must repay such financial support in 2021, in the amount of up to 50% of profit before taxation plus taxable expenses.

To be awarded the Aid for Salaries, the employer must fulfil the following requirements: (i) not to pay out dividends and bonuses until payment of salary for May 2020; (ii) to have at least a 30% reduction in revenue for April or May 2020, compared to last year's average (or season average for season employers); and (iii) the average salary of the 10% of the highest net salaries of the employees not to exceed approximately EUR 1,950 per month per employee, for the month for which the financial support is requested. The employer must also maintain the same number of employees (except in case of death or retirement of employees) for the duration of the Aid for Salaries, as well as two months after its termination. The Aid for Salaries cannot be awarded for employees who received a net salary higher than approximately EUR 650 for December 2019, January and February 2020.

To be awarded the Aid for Contributions, the employer must fulfil the following requirements: (i) not to reduce the number of employees in April, May and June 2020 compared to the number of employees as of 31 March 2020 (except in case of death or retirement of employees); (ii) no dividends and bonuses shall be paid until the submission of the annual account/financial statements for

2020; and (iii) the decrease in revenue in April, May or June 2020 must be higher than 30% compared to the average monthly revenue in 2019.

The Government has also set up a specialized website as an official source of information on Covid-19 and the measures it is taking regarding this public health and economic crisis (available in English on the following link: https://koronavirus.gov.mk/en).

B. Impact on the Energy and Infrastructure Sectors

While the Government still has not instituted any economic measures that are aimed specifically at the energy and infrastructure sectors, local companies active in these sectors can benefit from the general economic measures described above.

The Government has, nevertheless, taken some steps aimed at facilitating the operations of construction companies. The Government has extended the validity of the licences and authorisations of various types of participants in urban planning (planners, auditors of urban plans, both individuals and companies, where applicable) and in construction projects (certified engineers, auditors of architectural plans, contractors, construction supervisors, construction managers, facility managers, both individuals and companies, where applicable), which have expired, for the duration of the national state of emergency, as well as for 60 days as of the end of such state of emergency.

Also, energy and construction companies can benefit from some exemptions from the nationwide curfew the Government has introduced to reduce the spread of Covid-19. Namely, from Monday through Friday, the curfew is in effect from 4:00 p.m. until 5:00 a.m. the following day, while on weekends, a full curfew is in effect from Friday at 4:00 p.m. until Monday at 5:00 a.m. Special curfews apply for youths and the elderly, while people in need of emergency medical assistance are exempted from the restriction, as are some essential workers, such as police, armed forces and health workers. Exemption from the curfews is also provided to workers that work in shifts or that work at night, based on a permit issued by their employer. Movement in public places and public areas is allowed for at most two persons, but this does not apply to construction workers.

7.9 ROMANIA

7.9.1 Introduction to the energy market

The Romanian energy market has developed significantly in the past two decades, going through several key stages. Massive privatisation processes in electricity sector and oil, as well as major acquisitions in the private sector in refining capacities marked the first decade of 2000. Following such, Western utility groups build strong operations in Romania and invested in developing infrastructure and end-consumers services.

Further around 2010 significant investments have been made in renewable energy, first in wind capacities and afterwards solar. Romania's electricity mix is a balanced one, with coal, hydropower, natural gas, nuclear energy and wind power having comparable shares of capacity and power generation, however most of the generation capacities (with the exception of renewable sources based units) are fairly old and the new projects announced a while ago by the state have not materialized.
In the same period, based on public information the oil production dropped, as well as gas output. However, discoveries of new gas resources made in the Black Sea, may swift the figures.

In the past decade, Romania has fully liberalized the prices on the electricity market and on the gas market for consumers and the intention was that through to 2021, gas prices for households should also be fully liberalized. However, legislative changes at the end of 2018 have significantly affected the energy market (including the liberalization process), with consequences yet to come. In the same time the electricity and gas distribution/ transmission markets have been affected by the change of tariff regulatory periods which brought rather significant changes with potential impact on future investments.

7.9.2 Electricity

Market overview

In the last 15 years, the Romanian electricity market has been constantly developing and expanding. The currently applicable primary law was passed in 2012, in view of securing the implementation of the third energy legislative package adopted at the European level and has since gone through mild changes.

The electricity market is still divided into the competitive market and the regulated market. The initial calendar for liberalisation provided that the liberalisation of prices process should have been complete by 31 December 2017 (including for household clients).

However, following recent legislative amendments in the sector at the end of 2018, for household clients, the supply with electricity may still be performed in a regulated manner between 1 March 2019 and 28 February 2022 and moreover during the same period certain producers shall be obliged to sell electricity at regulated prices towards last resort suppliers. Thus, only for a short period of time (i.e., between 1 January 2018 and 28 February 2019) no regulated tariffs have been in place for electricity supply/ trading.

The regulated market includes regulated activities such as transmission, distribution or system services, as well as the regulated supply as mentioned above. The contractual relationships on the regulated market are based on regulated framework agreements and, respectively, regulated prices and tariffs determined and approved based on specific procedures issued by the Romanian Energy Regulatory Authority (ANRE).

As regards electricity trading, it is worth noting that Romania was one of the first European markets to develop an independent platform for energy transactions which currently supports the bilateral contracts market, the day-ahead market, the green certificates market, the emissions certificates market, the intra-day market, the centralized market with continuous double negotiation of bilateral energy contracts (OTC market), the centralized market for the universal service, the electricity market for the final large customers.

The main participants in the electricity market are electricity generators, electricity suppliers and traders, electricity distributors/ distribution networks operators, electricity transporter/ transportation network operator, and final clients.

Regulatory overview

The principles of the electricity market are currently regulated by the Electricity and Gas Law No. 123/2012 (published in the Official Gazette No. 485 of 16 July 2012), ("**Energy Law**") and detailed in secondary legislation including government decisions, decisions and orders issued by the relevant regulatory authority (the National Regulatory Authority for Energy - ANRE).

Relevant legislation in the field of electricity also includes: ANRE Order No. 12/2015 on the approval of the Regulation for granting licences and authorisations in the electricity sector (published in the Official Gazette No. 180 of 17 March 2015 and entered into force on 17 March 2015) ("**Electricity Licensing Regulation**"), ANRE Order No. 59/2013 on the approval of the Regulation for the connection of users to public electricity networks (published in the Official Gazette No. 517 bis of 19 August 2013 and entered into force on 18 December 2013) ("**Interconnection Regulation**"), and Law No. 220/2008 regarding the system for promoting production of energy from renewable energy sources (published in the Official Gazette No. 577 of 13 August 2010), as subsequently republished, amended and completed ("**Renewables Law**"), methodologies for determination of regulated prices and tariffs. The Energy Law establishes the general framework for electricity regulated activities, electricity licences and authorisations and the main rights arising therefrom, electricity market principles and the main competencies of the involved authorities (i.e., the relevant ministry – currently, the Ministry of Energy, the Romanian Energy Regulatory Authority – ANRE). According to the Energy Law, carrying out electricity related activities is usually subject to obtaining specific licences or authorisations from ANRE. The Electricity Licensing Regulation details the conditions and procedure to be followed for the granting of the main authorisations and licences. As regards electricity regulation, there are no recent changes to be noted herein.

The Government determines the national energy strategy, which defines the objectives of the energy sector and the best ways of achieving such objectives in the medium or long-term. The Ministry of Energy following the directions set out in the energy strategies and based on the Government programme, determines the energy policy consisting of measures for stimulating investment and research and development activities.

ANRE is the Romanian regulatory authority for energy, acting as an independent body responsible for regulating and ensuring a competitive electricity and gas market environment. In its capacity as regulatory authority in the electricity sector ANRE has attributions related to: (i) regulatory aspects; (ii) authorisation, supervision and control functions; (iii) reporting and information; and (iv) mediation and jurisdiction function.

Regulated electricity market activities

Pursuant to the Energy Law, the implementation of new energy capacities as well as the refurbishment of existing ones is based on establishment authorisations. Furthermore, generation, transportation, providing of system services, distribution and supply, trading of electricity as well as the management activities of the centralised electricity markets are carried out on the basis of licences granted in accordance with the law and in the case of public assets and public services also based on specific concessions granted by the relevant authorities. The performance of any activities without holding proper authorisations/ licences is subject to specific sanctions.

ANRE grants the following types of authorisations and licences for electricity related activities:

a. Establishment authorisations – must be obtained for erecting new electricity generation capacities, including co-generation capacities, or for the refurbishment thereof, if the installed electricity power of the capacities in question exceeds 1 MW or will exceed 1 MW;
b. Licences for: (i) the commercial exploitation of electricity generation capacities and of thermal energy capacities in co-generation; (ii) the electricity transportation service; (iii) the system service; (iv) the electricity distribution service; (v) the management of centralised markets; (vi) the electricity supply activity and (vii) the electricity trading activity.

The electricity supply and trading activities can be performed in Romania by an entity with headquarters in an EU member state (without a specific license issued by ANRE), if it possess a similar license/ regulatory document issued by the competent authority from its home jurisdiction and if it provides a statement that it will observe the Romanian technical and commercial regulations.

The applicable regulations set out the activities performed based on specific licenses and authorisations, as well as the documentation to be prepared and criteria to be met by each applicant/ project for each category of licences and authorisations. The criteria taken into account by the regulatory authority upon the analysis of the file are determined by the activities to be performed and are mainly related to the available technical and organisational, financial and human resources capabilities. Moreover, foreign entities from countries outside the EU are required to have a secondary office in Romania throughout the performance of the licensed/ authorised activity.

In general, changes which might occur with respect to the authorisation/licence holders (e.g., changes of the legal form, spin-off, merger, transformation, change of name, change of headquarter) must be notified to ANRE within 30 days as of their occurrence (merger and de-merger which must be notified with 60 days prior to their effective date). ANRE will decide either to annul the existing authorisation/ licence and issue a new authorisation/ licence or to amend the existing license/conditions joining the authorisation/ licence.

Any operations on the market is to be performed in compliance with the unbundling principles, implemented in the Romanian legal framework in accordance with the EU directives. In addition to the regulatory rules, merger control and corporate governance rules shall accordingly apply.

Main licences for electricity generation

Pursuant to the Romanian regulatory framework governing the electricity sector, the development, construction, commissioning and operation of a power plant is extensively regulated by a number of legislative acts (including extensive secondary legislation).

To this end, please note that for successfully performing the electricity generation activity, the following phases are required:

(a) *Construction phase (either for new generation capacities or upgrading existing ones):* characterised by obtaining an establishment authorization from ANRE;
(b) *Operating phase: the generator must hold a license for the commercial exploitation of electricity generation capacities issued by ANRE, as well as an environmental authorization;* on the basis thereof, the holder can operate the power plant.

In addition, in each phase other specific authorisations / permits issued by competent authorities/ entities will also be required. An assessment thereon must be made on a case by case basis. The licensed generator can also perform electricity-trading activities solely based on the commercial exploitation of electricity generation capacities license. For the period between 1 March 2019 and 28 February 2022, generators are under the obligation to deliver to last resort suppliers the electricity necessary for ensuring the consumption of household clients benefitting from regulated tariffs, pursuant to ANRE specific regulations. The remaining quantity of generated electricity must be publicly and non-discriminatory made available on the competitive market.

Trading and supply of electricity

Transactions between operators take place on the electricity market, which is divided into the wholesale market and the retail market. According to the provisions of the Energy Law, on the wholesale market, all transactions with electricity must be carried out on the centralized platforms managed by OPCOM in a non-discriminatory and transparent manner. Amongst the platforms managed by OPCOM we mention the centralised market for bilateral contracts, the centralised market with continuous negotiation (forward), the day-ahead market, the OTC platform, intra-day market, the platform for the large final customers, the platform for the universal service, the balancing market.

In respect of the electricity supply prices and tariffs, the market continues to include regulated segments. Following recent legislative amendments, for the period between 1 March 2019 and 28 February 2022, household clients can benefit from regulated prices for the supply of electricity although this segment of customers should have migrated to negotiated prices starting 1st January 2018. In fact, the household clients who became eligible customers received the right to request to return to the regulated segment and hence benefit of the regulated tariffs.

Final clients who have not exercised their eligibility right at the entry into force of the Energy Law, household clients and the non-household clients with an average number "on paper" of employees lower than 50 and an annual turnover or a total value of the assets from the accounting balance sheet (according to the annual financial reports) below EUR 10 million can be the beneficiaries of an universal electricity supply service having the right to be supplied with electricity at reasonable, transparent, easy comparable and non-discriminatory prices.

The Energy Law regulates the concept of supplier of last resort. This *type of supplier* is in charge with:

(a) providing electricity to household clients at regulated tariffs for the period between 1 March 2019 and 28 February 2022, pursuant to the secondary legislation enacted by ANRE in this respect; and

(b) providing the universal electricity supply service to the clients mentioned above at specific prices approved by ANRE. Even after the removal of the regulated prices, ANRE will have the right to endorse the prices at which the supplier of last resort intends to sell electricity to the abovementioned clients.

The regulated prices or tariffs must: (i) be non-discriminatory, objective and transparent, based on methodologies approved by ANRE; (ii) cover economically justifiable costs; (iii) allow the clients who do not exercise their eligibility right to choose the price or tariff they deem most favourable, out of those offered by the supplier, while complying with the conditions set out by ANRE; and (iv) ensure a reasonable rate of invested capital-earning capacity, in accordance with ANRE methodologies.

ANRE issues specific methodologies determining the regulated electricity tariffs applied by the last resort suppliers for household clients, as well as the prices charged by the former when providing the universal electricity supply service to the clients who can be the beneficiaries of such service.

Transmission and grid access

Network related services are regulated activities performed at regulated tariffs based on specific licenses and concessions as mentioned above. Moreover, the Energy Law considers the performance of the transmission and distribution service as being a natural monopoly, where each service is provided by only one operator for a predetermined area.

The network and system operation tariffs continue to be regulated through ANRE methodologies.

A new methodology for determining the distribution service has been recently enacted, since the fourth regulatory period started as of 1 January 2019. For determining the regulated distribution tariffs, the main principles set out in this methodology are as follows: (i) ANRE determines the regulated revenue for the distribution service based on a tariffs basket cap methodology (*cos de tarife plafon*); (ii) any justified cost associated with distribution activity is only considered once; (iii) the distribution tariffs are yearly approved for each distribution operator and are applicable for the entire network; and (iv) the justified costs of the distribution activity, the expenses related to optimal development of the network, as well as financial viability of the distribution operator are taken into account. For specific costs of the distribution operator, ANRE uses benchmarking techniques applied at the level of the distribution operators holding a concession license for the distribution service.

As regards grid access, the Energy Law sets out the obligation of the transmission/ distribution operators to grant access to the relevant networks. However, applicants are required to cover the specific costs of interconnection and also part of the costs required for the enhancement of the network. Access can be denied only for just cause if the connection affects the safety of the National Power System, through the non-observance of the technical norms and the performance standards or in case the transmission/ distribution network operator does not have the required capacities.

Pursuant to the Interconnection Regulation, interconnection to the electricity networks is based on an interconnection permit issued by the transmission/ distribution operator, the payment of the interconnection tariff by the applicant and an interconnection agreement between the applicant and the transmission/ distribution operator. The interconnection permit is a standard one and the interconnection agreement is to be executed based on a standard form issued by ANRE. The tariffs for interconnection to the public electricity networks are determined based on a methodology approved by ANRE, and they generally have three components: (i) a component relating to the costs of the interconnection installation; (ii) a component relating to the placing under tension of the use installation; and (iii) a component relating to the reinforcement of the grid upstream from the interconnection point.

7.9.3 Renewable energy

Market overview

Romania benefits from significant potential in various renewable energy sources: wind, solar, hydro, biomass, etc. A wide variety of renewable energy-based projects ("**E-RES**") have been developed in recent years, with solar and wind power-based projects being the most frequent ones. In promoting its resources, Romania was quick to adopt supporting mechanisms for all renewable energy sources consisting mainly of a system of mandatory quotas combined with green certificate trading. However, the existing support scheme is no longer available for new generation units, while the trading and issuance of green certificates will be possible up to 2032 for the generation units already benefitting from the green certificates support scheme.

Support schemes

The main support schemes for renewable energy in Romania are:

1. Promoting system of green certificates consisting of a system of mandatory quotas combined with green certificates ("**GC**") trading;
2. Support for joint implementation projects through Emission Reduction Units ("**ERU**s");
3. State aid scheme for supporting the development of new cogeneration units using biomass or residual gases;
4. State aid scheme for supporting the development of new electric/ thermal production units using biomass, biogas or geothermal water.

GC promoting system

In Romania the main system for promoting electricity generation from E-RES functions as a staid aid scheme (and for generation units exceeding a certain level as individual state aid which needs the approval of the European Commission) and consists of a system of mandatory quotas combined with GC trading. Based on such system, every year each electricity supplier must purchase a number of GC equal to the mandatory quota provided by the relevant regulations multiplied with the quantity of electricity yearly supplied to end clients. This support scheme is still applicable for production capacities certified as production units using E-RES prior to 2017. Currently, only the generators operating such units are taking part in this scheme, being issued GCs and having the possibility to trade them up to 2032. Although each issued GC has a validity period of 12 months, pursuant to recent amendments all the GCs issued after April 1, 2017 and all the postponed GCs can be traded up to 2032.

The transport system operator issues GCs to the relevant generators in consideration of the quantity of E-RES generated and delivered into the network. Under such a system the GC certifies the generation from renewable energy sources of a certain quantity of electricity which may be traded distinctively from the associated electricity (in a distinct regulated market) and which represents a benefit for the E-RES generators in exchange for delivering "clean" electricity into the network. GCs are traded on the centralized green certificates market managed by OPCOM. Recent amendments to the Renewables Law also impacted how the GCs are traded. To this end, we note the following main aspects:

(a) A GC can be the object of only one transaction between the generator, as seller and the supplier, as purchaser. By exception, the generator, part of a bilateral agreement with a supplier, which is in the situation of not observing the number of green certificates contracted, may acquire the difference from the GC centralized markets, only to cover said difference.

(b) Starting with the 1 September 2017, the transaction of GCs is allowed only to generators and suppliers, in a transparent, centralized and non-discriminatory manner, on the anonymous centralized markets and/ or on the centralized market for E-RES which benefit from the GCs managed by OPCOM. By exception, all suppliers can trade as purchasers on the centralized market for E-RES which benefit from the GCs.

(c) Bilateral sale-purchase agreements for GCs concluded prior to 1 April 2017 are still valid until their expiry, without the possibility to extend them. Starting with 1 April 2017, execution of addenda to the bilateral agreements is forbidden, in what concerns the increase of the green certificates number traded through them.

(d) Generators and public authorities owning production capacities using E-RES with maximum 3 MWh per generator, benefitting from the GCs support scheme/ benefitted from the GCs support scheme and still having GCs, can enter into directly negotiated bilateral sale-purchase agreements for GCs only with the suppliers of end-clients for the sale of electricity and/ or GCs.

7.9.4 Natural gas

Market overview

The natural gas market is still divided into the competitive market and the regulated market. On the former, the prices for supply of gas are formed freely, irrespective whether the transactions are wholesale or retail The regulated market includes activities such as transmission, distribution or storage as well as regulated supply to household customers and thermal energy producers for the quantities destined for the heating of household customers, which, due to the liberalisation process, was limited, until recently, to household consumers. The contractual relationships on the regulated market are based on regulated framework agreements and prices and tariffs determined and approved based on specific procedures approved by ANRE or set by other normative acts.

Until late 2018, the liberalisation of the Romanian natural gas market was on track and the full liberalisation of the natural gas market was set for 2021. However, the Romanian gas market has undergone a significant transformation in recent months due to the adoption of Government Emergency Ordinance No. 114/2018 regarding the establishment of several measures in the public investment domain and of some budgetary – fiscal measures, amending and supplementing certain normative acts and extending certain terms ("**GEO 114/2018**") as amended and supplemented.

GEO 114/2018 has severely affected the regulatory framework and has reversed the liberalisation of the natural gas market by imposing, for the period of May 1, 2019-February 28, 2022, a price cap on gas from the domestic production destined for the consumption of household customers and for the district heating of household customers. Moreover, in the abovementioned period, natural gas producers have the obligation to sell with priority to suppliers or thermal energy producers in order to ensure the entire consumption of household customers and thermal energy producers for the heating of household customers.

Regulatory overview

The Energy Law is also the main piece of legislation governing the natural gas sector. In the case of upstream activities the provisions of the Energy Law are complemented by those of the Petroleum Law No. 238/2004, as amended and completed (published in the Official Gazette No. 535/2004) ("**Petroleum Law**"). Further regulations are included in secondary legislation, such as: ANRE Order 34/2013 approving the Regulation for granting of set-up authorizations and licenses in the natural gas sector (published in the Official Gazette No. 427/2013) ("Natural Gas Licensing Regulation"), ANRE Order No. 64/2018 approving the Framework conditions for the validity of the natural gas supply licence (published in the Official Gazette No. 334/2018), ANRE Order No 84/2014 approving the Framework conditions for the validity of the natural gas distribution licence (published in the Official Gazette No. 699/2014), ANRE Order No. 172/2018 approving the Framework conditions for the validity of licence for the operation of the natural gas transmission system (published in the Official Gazette No. 856/2018), ANRE Decision No. 824/2004 approving the regulation relating to the regulated access to the underground storage of natural gas (published in the Official Gazette No. 562/2004) ("Storage Regulation"), ANRE Order No. 97/2018 for the approval of the Regulation for access to natural gas distribution system (published in the Official Gazette No. 447/2018) ("Distribution System Access Regulation"), ANRE Order No. 82/2017 for the approval of the Regulation for the connection to the natural gas transmission system (published in the Official Gazette No. 739/2017) ("Transmission System Connection Regulation").

ANRE Order No. 16/2013 approving the Network Code for the natural gas national transmission system (published in the Official Gazette No. 171/2013) ("Network Code").

The Energy Law sets out the general framework for carrying out activities specific to the natural gas sector in competitive and transparent conditions. To this end, the Energy Law sets forth the main principles regarding:

(a) Competences of the relevant authorities for the natural gas sector;
(b) Concession of transmission, storage and distribution services;
(c) Authorizations and licenses required for regulated activities;
(d) Production, transmission, distribution, underground storage and supply of gas as well as the operating of centralized markets;
(e) Access and connection to the network;
(f) Liquefied natural gas ("LNG");
(g) Ensuring the quality of equipments, installations, machines, products and procedures used in the natural gas sector;
(h) New infrastructure;
(i) Public service obligation;
(j) Natural gas market; and
(k) Prices and tariffs.

The Government, the Ministry of Energy and other specialised institutions of the central public administration take measures to achieve the objectives included in the energy strategies and monitor the level of compliance. The Ministry of Energy develops the national energy policy in the natural gas field and ensures its compliance with it.

At present, the regulatory authority in the field of natural gas is ANRE which functions as an autonomous public institution, under parliamentary control.

Regulated natural gas market activities

In order to set up, operate and/or make changes to production, transmission, storage, and distribution capacities of natural gas, and to carry out the supply, transmission, storage, and distribution activities in the natural gas sector, Romanian or foreign entities must possess authorisations and/or licences issued by ANRE based on specific regulations.
Concessions must be awarded by public tender by the relevant authorities in relation to the use of public property assets required for the transmission of natural gas and storage (facilities and systems), and the public services of transmission, storage and distribution of natural gas.

ANRE issues the main types of permits for the natural gas sector:

(a) Set-up authorisations for new upstream pipelines, transmission, storage, distribution systems and
(b) Licences for performing activities such as supply of natural gas, trade of natural gas, operation of transmission, distribution or storage systems, operation of upstream pipelines and managing centralized markets.

Material provisions of the natural gas market law and licensing regulations

Similar to the electricity market, the applicable regulations require that certain documentation is prepared and criteria met by each applicant/ project for each category of licences and authorisations. In principle, the applicant for a natural gas authorization/ license must be a legal person with its registered office in Romania.

Legal persons headquartered in an EU member state, holders of natural gas supply or trading licenses or other similar documents issued by a competent authority of an EU member state can perform natural gas supply or trading activities based on a confirmation decision issued by the President of ANRE and without a licence issued by ANRE. In case the applicant is a non-EU foreign legal person without a stable office in Romania, the Natural Gas Licensing Regulation requires the establishment of a secondary office in Romania. ANRE shall analyse the submitted documents in order to assess their conformity with the legal requirements and will notify the applicant, within 30 calendar days from the submission of the request, in case there are any shortcomings. The authority takes a decision with respect to the specific authorization/license within 30 days from the date of the submission by the applicant of the complete documentation.

The reasons for refusal to grant an authorization/ license must be objective and non-discriminatory, the refusal is issued through a decision of the ANRE President and the applicant may challenge the decision in the administrative disputes court, pursuant to the law.

Exploration and production

The exploration and production of natural gas are governed by petroleum laws and corresponding regulations, as detailed below.

Transmission and access to the system

Network related services are regulated activities performed at regulated tariffs based on specific licenses and concessions as mentioned above. The transmission system operator cannot refuse access to the system and has the obligation to finance the necessary works, in conditions of economic efficiency and in accordance with ANRE regulations. The applicant may contribute in a certain portion or in full to the initial financing of the relevant objectives/ pipelines and the transmission system operator has to reimburse the applicant for its contribution. The Network Code and the Transmission System Connection Regulation further detail the procedure and the related steps to be pursued.

Trading and supply

The natural gas market continues to be formed of two segments: the competitive segment and the regulated segment. The competitive segment of the market is related to the trading of natural gas between suppliers, traders, and eligible customers. In the competitive segment, prices are formed freely, based on demand and supply and competition mechanisms.

In relation to the competitive sector, centralized markets on which gas is traded have been established and the authorities have designed mechanisms to constrain market participants to trade on these centralised markets in view of increased liquidity and competition in the gas market. To this aim, market participants have an obligation to buy/sell certain minimum amounts of gas on the centralized market.

The regulated segment of the market consists of natural gas supply to household customers and thermal energy producers for the quantities used for the heating of household customers, natural gas transmission, underground storage and distribution at regulated prices. For this segment of the regulated market, the tariffs and prices systems are set by ANRE based on specific methodologies or by other normative acts.

For the period May 1, 2019 - February 28, 2022, GEO 114/2018 introduced the obligation of producers to sell with a price of RON 68/ MWh the gas quantities resulted from the current domestic production to suppliers of household customers and suppliers of thermal energy producers (in this case only in what concerns the quantities used for the heating of household customers).

Moreover, natural gas producers have the obligation to sell with priority to suppliers or thermal energy producers in order to ensure the entire consumption of household customers and of thermal energy producers (in this case only in what concerns the quantities used for the heating of household customers). The sale of natural gas to suppliers of household customers and to suppliers of thermal energy producers for the quantities of gas destined for heating for household customers shall be performed using the framework agreements approved by ANRE.

Forthcoming developments

The recent amendments to the Energy Law have caused a lot of uncertainty and have severely affected the natural gas sector. Furthermore, secondary legislation will have to be issued by ANRE in order to implement the recent amendments to the Energy Law.

While, the TSO has made progress towards ensuring physical capabilities for export of gas to other countries and in this respect, there are several cross-border interconnection projects in various stages of development, the amendments introduced by GEO 114/2018 will certainly impact the development of these inter-connection projects.

Also, it remains to be seen how the producers will be able to comply with the centralized market obligation recently imposed.

7.9.5 Upstream and the oil market

Market overview

Oil-related activities can be carried out by Romanian or foreign legal entities, in compliance with the conditions provided by the regulatory framework.

The oil market is open to all interested participants which are able to prove their financial and technical capabilities for carrying out oil-related activities. The market numbers certain major players, either at global level or regional one, such as ExxonMobil and OMV Petrom SA. The interest in Romania's gas production capabilities has raised recently with the discovery of certain important reserves in the Black Sea.

Regulatory overview

Unlike the natural gas sector, the Romanian oil market is regulated only to a certain extent. Oil-related upstream activities (e.g., exploration, development, and production) are mainly regulated by the Petroleum Law and the subsequent Methodological Norms for its implementation, approved in Government Decision No. 2075/2004 (published in the Official Gazette No. 1170/2004) ("**Methodological Norms**"). In addition, as a novelty, the Romanian Parliament has decided to enact a special piece of legislation applicable for the offshore oil and gas sector namely the Offshore Law No. 256/2018 regarding certain measure for the implementation of operations by titleholders of oil agreements related to offshore blocks (the "**Offshore Law**").

The Petroleum Law contains the main principles applicable for carrying out oil activities; the principles of the regime of classified information; the main types of oil activities and concessions related thereto (petroleum agreements) and the main rights and obligations arising from the oil concessions together with the situations in which such may be suspended or revoked. The Methodological Norms describe in more detail the public procedure for granting of oil concessions and the regime of the various types of oil concessions as well as the rights and obligations of the titleholders.

The Offshore Law regulates a special regulatory regime applicable to offshore oil operations covering aspects such as:

(a) Permitting of petroleum works carried out in the Black Sea;

(b) Land access rights;
(c) Fiscal provisions;
(d) Local content obligations;
(e) Obligation to trade on the Romanian centralized gas market.

The National Agency for Mineral Resources ("**NAMR**") is the specialized authority for the oil sector.NAMR is responsible for maintaining the Petroleum Book, a registration document comprising all data about the legal regime of the areas: the development and exploitation perimeter; ownership; topographical situation of the works related to the oil activities; the oil and production resources/ reserves; and data regarding the demarcation of oil perimeters and operations in the prospecting and exploration stages. To our knowledge, this instrument has not yet been created by NAMR.

Regulated oil market activities

NAMR is responsible for granting concessions for petroleum activities (such as exploration, development, exploitation, storage, transmission, etc.) and public assets related thereto. The concession is awarded by public tender for a term of 30 years with the possibility of extension for another 15 years.

NAMR may also grant prospecting permits which allow the titleholder to undertake exploration activities in a specific concession block for a maximum period of three years. The term of a prospecting permit cannot exceed three years.

The concession takes the form of a petroleum agreement concluded between NAMR and the Romanian or foreign legal entity having won the public tender process. The concession enters into force subject to specific governmental approval. The titleholder of the concession pays an oil royalty for the entire duration of the concession. The percentage of the royalty payable by the titleholder of the petroleum agreement is determined in consideration of the type of activity undertaken by the titleholder (i.e., production, transmission, underground storage of natural gas).

The main types of petroleum agreements are:
(a) Exploration-development-exploitation petroleum agreement;
(b) Development-exploitation petroleum agreement;
(c) Exploitation petroleum agreement;
(d) Development petroleum agreement;
(e) Underground storage of natural gas petroleum agreement – please note that the performance of the natural gas storage activity requires both an ANRE licence and a NAMR petroleum agreement;
(f) Petroleum agreement for the concession of the national oil pipeline system; and
(g) Petroleum agreement for the concession of the oil terminals.

The granting of oil petroleum agreements is based on transparent and non-discriminatory criteria. The transportation of crude oil is performed through main pipelines on a contractual basis governed by a standard agreement approved by NAMR. The transportation agreements may not include unjustifiably restrictive conditions, or conditions endangering the security of supply and the quality of services. The transport of crude oil through the national transport system is a public national interest service for which Conpet possesses the concession. Conpet has the status of ordinary transport operator under the Petroleum Law and is thus obliged to ensure non-discriminatory treatment for all its clients and perform oil transport based on tariffs regulated by NAMR.

Material provisions of the oil market law and licensing regulations

A titleholder of a petroleum agreement may transfer to another legal entity, in full or in part, the rights and obligations acquired on the basis of the petroleum agreement only with the prior approval of NAMR, under the sanction of nullity of the transfer. The approval of the transfer shall be made provided that the transferee can prove that it has the technical and financial capacity necessary for the performance of the oil activities in compliance with the conditions provided in the petroleum agreement.

Forthcoming developments

The natural gas resources discovered in the Black Sea are estimated to be in excess of 100 billion cubic meters. Nevertheless, due to the unpredictable regulatory framework, until now, only one of the offshore titleholders, but not the titleholders of the blocks where the largest reserved were discovered, has taken the final investment decision.

7.9.6. Impact of the coronavirus pandemic on the energy and infrastructure[56]

Following the declaration of the state of emergency in Romania as of 16 March 2020, recently extended until 16 May 2020, certain support measures meant to diminish the negative impact on the economy of the implemented solutions for the prevention and limitation of the disease have been adopted.

A. Covid-19 Response Investment and Support Initiative – General

Support measures applicable irrespective of the industry:

I. General measures:

I.1 Employment measures applicable to all employers acting in Romania during the state of emergency:

0. Unemployment support for employers whose activities are totally or partially reduced or interrupted, following the effects of the Covid-19 pandemic. The level of the unemployment support is established at 75% of the base salary corresponding to the position held by each affected employee, but no more than 75% of the average gross salary, and is borne from the unemployment insurance state budget.
1. Days off to be paid from the state budget for parents of children (subject to age/ health condition criteria) who are enrolled in educational institutions closed pursuant to the authority's decision where the workplace is not compatible with work from home or telework; for certain workplaces, the possibility of a days-off arrangement is subject to the employer's agreement. The daily allowance paid to such employees is of 75% of their daily regular salary, but no more than the corresponding value for a day of 75% of the average gross wage;

I.2 Tax (fiscal):

(a) No late payment interest/penalties will be imposed for non-payment of tax obligations during the emergency situation and 30 days after the end thereof;
(b) No forced execution of tax debts;
(c) Swift reimbursement of VAT starting the month of April;
(d) Suspension of tax inspections which cannot be performed remotely;
(e) Deferral of terms for payment taxes on buildings and land from 31 March to 30 June;
(f) Taxpayers applying the annual computation for corporate tax are allowed to calculate their quarterly tax based on the actual profit for the quarter instead of using last year's profit as a reference;
(g) Bonus awarded for taxpayers that pay the corporate income tax related to the first quarter of 2020 until 25 April 2020 ranging from 5% to 10%;

During the entire state of emergency and 30 days after its termination, VAT is not required to be paid in customs on imports of medicines, protective equipment and other medical devices and equipment and sanitary materials used in the Covid-19 control, but accounted for as reverse charge.

II. Moratorium measures

Currently, there is only one enactment that provides a payment moratorium – an emergency ordinance intended to ensure the deferred payment of instalments, for both natural and legal persons (without distinction between the latter), that fulfill certain conditions. This mechanism in force consists of the possibility of debtors to obtain, upon request, a suspension of their obligation to pay

[56] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

the bank loans or leasing agreements (principal amounts, interest, fees) instalments for a period of one to nine months, but no later than 31 December 2020. However, the Government ordinance has to be approved by the Parliament by law, the Parliament being entitled to propose amendments. The Romanian Senate has already made certain amendments to the Government ordinance (for example, with respect to the debtors and creditors that fall under the scope of the moratorium and the conditions that must be fulfilled in order for the moratorium to be granted).

It is important to note that there is a competing enactment, not yet in effect, whose provisions seem at times contrary to those of the Government ordinance in force. However, this law is still to be promulgated by the Romanian President and its constitutionality has also been challenged, primarily due to the fact that it creates a legislative parallelism.

III. Measures applicable only for small and medium-sized enterprises (SMEs) which are mainly divided into two categories:

II.1 Measures conditioned upon the prior obtaining of the state of emergency certificate ("SEC")

SEC are to be issued to SMEs whose activity has been totally or partially interrupted as a result of the measures taken by public authorities during the state of emergency or who registered a decrease of at least 25% in revenues or payment receipts in March compared to the average registered in January and February 2020.

Based on SEC, SMEs may benefit of:

(a) postponing the payment of utilities and of the rent for headquarters and secondary offices;
(b) possibility to benefit from the adaptation of ongoing agreements under which force majeure is called by the other party;
(c) exemption from the obligation to pay penalties for the failure to perform certain obligations from the contracts concluded with public authorities.

II.2 State aid scheme for SMEs which are in distress due to the Coronavirus outbreak which consists in guarantees issued by the State for certain financing and subsidies for the interest. The applicability of this state aid scheme is not conditioned upon the prior obtaining of the certificate, but the beneficiary will have to undertake not to lay off employees until 31 December 2020.

B. Impact on the Energy and Infrastructure Sectors

Energy Sector

The legislation related to the state of emergency provides the obligation to ensure the continuity of energy supply and several measures in this respect have been adopted (such as the obligation to ensure the isolation at the workplace in case of employees who are essential for ensuring the proper functioning of the energy transmission system, prohibition to start collective labour conflicts, etc).

Even though the companies from the energy sector will continue their activity, their business is mainly impacted by:

(a) the overall consequences of the Covid-19 pandemic on the entire Romanian market, such as decrease of the energy consumption due to the closure of certain businesses, exemption from payment of the utilities' invoices mentioned above, etc;
(b) capping of the prices for electricity, heat, natural gas and fuel prices at the level applicable on 29 March 2020 throughout the entire duration of the state of emergency;
(c) This measure raises several practical issues considering the lack of details and further legislation is expected to be adopted on this topic.
(d) freeze of the sale of majority packages of shares in the companies from the Energetic National System, both state owned and private. We note however that there is no clear definition of the "Energetic National System".

7.10 SERBIA

7.10.1 Introduction to the energy market

The Serbian Parliament has adopted the current Law on Energy *(Zakon o energetici*, Official Gazette of Republic of Serbia, No. 145/2014 and 95/2018), at the end of 2014. The main driver behind the overhaul of the regulatory framework is alignment with the third energy package and removal of barriers for development of renewable energy projects. The energy markets are still dominated by the incumbent utilities: "Elektroprivreda Srbije" the state owned electricity utility runs the electricity market as the dominant producer, public supplier and distributor ("**EPS**"); "Srbijagas", the state-owned gas utility, holds the grip on the gas sector as the TSO, producer and supplier; the oil sector is dominated by "NIS", former state-owned oil utility now in majority ownership of Gazprom. While NIS has already undergone internal restructuring, the reorganization of Elektroprivreda Srbije and Srbijagas is pending.

7.10.2 Electricity

Market overview

The state-owned utility EPS with its wholly owned subsidiaries is still virtually the only producer, distributor and supplier on the electricity market. Restructuring of EPS has started with the aim of having a holding company and three separate companies, one for each of production, distribution and supply. Currently, there are seven subsidiaries involved in production, one subsidiary acting as a power distribution company and one is acting as power supplier. Power transmission is separated from EPS and is handled by "Elektromreže Srbije", another state-owned entity.

Regulatory overview

The Law on Energy covers all relevant energy sectors, i.e. electricity, district heating, oil and gas and deals with:

(a) the rights and obligations of the relevant stakeholders in the energy sector;
(b) the issuance of authorisations for performance of energy activities;
(c) the issuance of permits for the construction of energy facilities (energy permit – "energetska dozvola");
(d) regulated prices;
(e) renewable energy;
(f) specific rules for the electricity, gas, oil and district heating sectors;
(g) access to the energy system, i.e. transmission and distribution systems; and
(h) supply of energy.

The key stakeholders in the Serbian electricity market are:

(a) The Ministry of Mining and Energy ("**Ministry**") – responsible for preparing the most important strategic and action documents for adoption by the Government of Serbia, enacting various implementing regulations and technical standards and overseeing the overall implementation of the Law;
(b) The Agency for Energy of the Republic of Serbia ("**AERS**") – an independent, regulatory body established pursuant to the Law on Energy. Its primary tasks are to develop and enhance the electricity and gas market based on the principles of nondiscrimination and effective competition by creating a stable regulatory framework;
(c) Transmission system operator – "Elektromreže Srbije" ("**EMS**") – a state-owned public company in charge of the development, safe and reliable functioning of the transmission system, enforcement of non-discriminatory and economical access to the transmission system;
(d) Distribution system operator – "EPS Distribucija" ("**EPSD**") – a company 100% owned by EPS in charge of the development, operation and functioning of the distribution system. The distribution system operator, being part of a vertically integrated electricity utility, is supposed to be independent in terms of its legal form, organization, and decision making process from other activities which are not connected to the sitribution of electricity.
(e) EPS - "Elektroprivreda Srbije" – a state-owned vertically-integrated electricity

utility, engaged in power generation and supply, and 100% owner of the distribution system operator.

Regulated electricity market activities

The Law on Energy prescribes the following energy activities in the electricity sector:
(a) The production of electricity;
(b) The combined production of electricity and heating energy;
(c) The transmission of electricity and management of the transmission system;
(d) The distribution of electricity and management of the distribution system;
(e) The distribution of electricity and management of the closed distribution system;
(f) The supply of electric energy (i.e. i*ncluding sale to the end consumers*);
(g) Bulk supply of electric energy (i.e. *excluding sale to the end consumers*); and
(h) Electricity market operation.

The performance of each of these activities is subject to the granting of a licence by the AERS. Furthermore, activities under (c) and (d) are considered activities of general interest and, therefore, may be performed either by public, state-owned companies or by privately owned companies expressly authorized by the Government of Serbia to perform a specific activity of general interest pursuant to the Law on Public Companies (*Zakon o javnim preduzećima*, Official Gazette of Republic of Serbia, No. 15/2016) or the Law on Public Private Partnerships and Concessions (*Zakon o javno-privatnom partnerstvu i koncesijama*, Official Gazette of Republic of Serbia, No. 88/2011,15/2016 and 104/2016).

Generation

The development of generation capacities is reliant on the granting of numerous permits by various state authorities. A licence for the production of electricity is granted only at the end of the entire development process and follows after the issuance of the operational permit for the power plant. Regarding the phases of the construction of any "small" electricity generation facility, the construction of any larger power plant and the assessment of environmental impact (Law on Assessment of the Environmental Impact, Official Gazette of Republic of Serbia, No. 135/2004 and 36/2009), there are no recent amendments on their regulatory framework.

In cases, when the production of electricity in a power plant is based on natural resources (e.g. coal) or public goods (e.g. water), the prospective producer of electricity must acquire the right to use such a natural resource or public good, either by obtaining a concession in a competitive tender procedure pursuant to the Law on Public Private Partnerships and Concessions or through obtaining sector-specific permits pursuant to the Law on Mining and Geological Explorations (*Zakon o rudarstvu i geološkim istraživanjima*, Official Gazette of Republic of Serbia, No. 101/2015 and 95/2018) or the Law on Waters (*Zakon o vodama*, Official Gazette of Republic of Serbia, No. 30/2010, 93/2012, 101/2016 and 95/2018). Finally, the Law on Planning and Construction (*Zakon o planiranju i izgradnji*, Official Gazette of Republic of Serbia, No. 72/2009, 81/2009, 64/2010, 24/2011, 121/2012, 42/2013, 50/2013, 98/2013, 132/2014,145/2014 and 83/2018) provides for various permits, approvals and other documents to be issued before and during the course of the construction of a power plant.

The most important of these are the construction permit and the operational permit. The operational permit is issued only upon a successful technical inspection and a trial operation of the power plant.

Trading and supply of electricity

The Law on Energy distinguishes between the regular market activity of supply and the activity of bulk supply of electricity. The differentiating factor is that the bulk supply excludes supply of the end consumers.

The Serbian energy market is now fully open. The Law on Energy prescribes that all electricity consumers have the right to freely choose their supplier. The Rules on Changing the Supplier specify the procedure for changing the supplier of electricity, deadlines and conditions. However, EPS is practically still the only reliable supplier on the Serbian market having around 98 per cent of the market share. The new Law on Energy introduces the concept of guaranteed supplier, in charge of guaranteed supply of households and small consumers. The guaranteed supplier is to be selected by the Government pursuant to a public tender, for a period of up to five years. However, this process will be launched only after AERS determines that there is no need for further control of the price of electricity for households and small consumers. Until then, EPS performs the duties of the guaranteed supplier.

The Law on Energy also introduces the concept of the supplier of last resort. The supplier of last resort should also be selected by the Government on the public tender. Until then, EPS performs the duties of the supplier of last resort, distribution systems as well as the price of electricity for guaranteed supply of electricity.The Law on Energy divides the electricity market into a bilateral electricity market; a balance electricity market; and an organised electricity market.

A bilateral electricity market is based on bilateral power purchase agreements. A balance electricity market enables the transmission system operator to secure proper operation of the transmission system by selling and purchasing the required quantities of electricity. It is managed by the transmission system operator. An organised electricity market comprises day-ahead and intra-day trading and is supposed to be managed by the market operator. EMS holds licences for both transmission system operator and market operator. The Market Rules prepared by EMS and approved by AERS are in force as of 2012 and amended in 2014 and 2016. The Market Rules govern the balance electricity market and there are yet no specific rules to govern the organised electricity market (i.e. power exchange).

Transmission and grid access

Pursuant to Article 117 of the Law on Energy, EMS must allow third party access to the transmission system on a non-discriminatory basis, under regulated prices and through transparent procedure. Access may not be denied on grounds of possible future congestion in the transmission capacities or on ground of additional costs arising from necessity of increase in capacities in the vicinity of the connection point.

The process for the connection of the power producers and large consumers to the transmission system starts with preparation of a connection study to be developed by EMS at the cost of the party interested in connecting to the transmission system. Connection study determines the possibilities for connection to the transmission system and is prerequisite for preparing further planning and technical documents and the necessary planning documents and permitting process.

Following the preparation of the connection study the party interested in connecting to the transmission system and EMS enter into agreement on the preparation of the necessary planning and technical documentation and acquiring the permits necessary for construction of the connection infrastructure. A precondition for connection of the producer and/or consumer of electricity to the transmission system is obtaining a connection approval from EMS. The request for issuing the connection approval may be submitted upon issuance of the construction permit for the facility being connected to the transmission system. The deadline for the granting of a connection approval is 60 days for electricity producers and 30 days for consumers. AERS is responsible for deciding on any appeal submitted against a decision issued by EMS. The decision of AERS is final in administrative proceedings but may be challenged before the Administrative Court of Serbia in administrative accountancy proceedings.

EMS will grant the connection approval if the planned equipment and installations of the power plant/facility are determined to be in accordance with the opinion issued by EMS and the relevant technical rules and regulations. The connection approval granted by EMS specifically determines the connection point, technical conditions for connection, place and manner of measuring electricity, deadline for establishing connection and the cost of connection.

Upon issuance of the connection approval EMS will be obliged to connect the constructed facility to the transmission system if:
- the conditions from the connection approval are fulfilled;
- operational permit or trial permit has been obtained for the facility and for the connection line;
- supply agreement is in place;
- balancing responsibility and access to the system have been determined for the delivery point.

7.10.3 Renewable energy

Market overview

Serbian power generation is dominated by the large hydropower plants with a total installed power of 2,832 MW which amounts to approximately 34 per cent of the total installed power generation capacity in Serbia. In the last couple of years, a total of 111 small hydro-power plants ("HPP") have been developed and obtained the status of privileged power producer and 35 small HPP have obtained a provisional privileged power producer status and are under development. Thus, the number of small HPPs is steadily increasing. Wind energy is considered as the renewable energy source with the highest potential. Until now, four wind power plant have obtained the status of privileged power producer, with total installed capacity of 25 MW. Another four wind power plants with a total of 300 MW of installed capacity have been completed and are in the commissioning process, whereas remaining two wind power plants with a total of 170 MW of installed capacity are in the financing stage.

The use of biomass, geothermal and solar energy is negligible at the moment. The mandatory renewable energy target by 2020 amounts to 27 per cent and Serbia will probably fail to reach it partly because of the unexpected increase in energy consumption and partly due to slower development of the new renewable energy-based production facilities

Support schemes

Support for renewable energy generation has been one of the key focus points of the Ministry in the last couple of years. The incentives prescribed by the Law on Energy are: mandatory purchase of renewable energy by the public supplier, feed-in tariff, balancing responsibility of the public supplier as well as priority dispatching.

The Law on Energy distinguishes between the temporary privileged producer, privileged producer, and the renewable energy producer. The status of temporary privileged producer may be obtained by the decision of the Ministry, upon the issuance of a construction permit for a relevant renewables project and posting a deposit or a bank guarantee in the amount of two per cent of the investment.

The status of privileged producer is obtained by the decision of the Ministry for a relevant renewables project subject to fulfillment of the following pre-conditions: operational permit has been issued, a separate measurement point has been procured, the installed production capacity of the wind/solar power plant is within the quotas prescribed by the Government decree, the production facility is newly constructed or reconstructed with unused equipment installed and the licence for production of electricity is issued by AERS.

Back in 2016, the Government has adopted a set decrees governing the renewable energy industry (i.e. decrees on the status of privileged producers, the set of incentives as well as the standard power purchase agreement). The set of incentive decrees was supposed to expire at the end of 2018 but it was extended for one more year, i.e. until the end of 2019.

The Law on Energy also introduced the system of certificates of origin to be set up and managed by the Serbian transmission system operator. In early 2014, the Government adopted the Decree on Guarantees of Origin (*Uredba o garanciji porekla*, Official Gazette of Republic of Serbia, No. 82/2017) further regulating the procedure of issuance of certificates of origin.

7.10.4 Natural gas

Market overview

The Serbian natural gas market significantly depends on imported natural gas, i.e. approximately 82 per cent of consumption is imported.

Regulatory overview

Legal framework

The gas sector in Serbia is governed by the Law on Energy and bylaws elaborating it as main pieces of gas legislation. The following important laws (and supporting bylaws) are also applied to the gas sector:

(a) Law on Pipeline Transportation of Gas and Liquid Hydrocarbons and Distribution of Gas Hydrocarbons (*Zakon o cevovodnom transportu gasovitih i tečnih ugljovodonika i distribuciji gasovitih ugljovodonika*, Official Gazette of Republic of Serbia, No. 104/09);
(b) Law on Public Enterprises (*Zakon o javnim preduzećima*, Official Gazette of Republic of Serbia, No. 15/2016);
(c) Law on Public Private Partnerships and Concessions (*Zakon o javno-privatnom partnerstvu i koncesijama*, Official Gazette of Republic of Serbia, No. 88/2011,15/2016 and 104/2016);
(d) Law on Planning and Construction (*Zakon o planiranju i izgradnji*, Official Gazette of Republic of Serbia, No. 72/2009, 81/2009, 64/2010, 24/2011, 121/2012, 42/2013, 50/2013, 98/2013, 132/2014, 145/2014 and 83/2018);
(e) Law on Mining and Geological Explorations (*Zakon o rudarstvu i geološkim istraživanjima*, Official Gazette of Republic of Serbia, No. 101/2015 and 95/2018).

The new Law on Energy opened the natural gas market so that now all end customers have the right to choose their gas supplier freely. Similarly to the electricity sector, the Rules on Changing the Supplier specify the procedure for changing the supplier of electricity, deadlines and conditions; in 2012, "Srbijagas" accounted for 69 per cent of total natural gas sales.

The circle of customers entitled to purchase gas from the public supplier under regulated prices is gradually shrinking: under the new Law on Energy, regulated prices apply only to households and small consumers (i.e. whose consumption is up to 100,000m^3 and connection to the distribution system).

Regulated natural gas market activities

The Law on Energy provides for the following natural gas related activities:

(a) gas transportation and operation of the gas transport system;
(b) gas storage and operation of the gas storage facilities;
(c) gas distribution and operation of the gas distribution system;
(d) gas supply; and
(e) public supply of gas.

The performance of any of these activities is subject to the issuance of an energy licence by AERS as a principle regulatory body in the gas sector. Licences are issued within 30 days of the proper application, provided that all conditions are met. The validity period of the licences for the activities in the gas sector is 10 years and they are renewable upon the request of the energy undertaking, provided that the request is filed no later than 30 days prior to the expiry date.

Licences are not transferable. AERS is entitled to suspend the licence temporarily, should the energy undertaking fail to:

(a) comply with the requirements of the Law on Energy;
(b) maintain energy facilities in accordance with the regulations;
(c) comply with the obligations imposed by the licence;

(d) keep separate accounting for each energy activity; and
(e) determine the prices according to the methodologies rendered by AERS.

If the energy undertaking does not remedy the breach within a given deadline, which is not shorter than 30 days and not longer than 90 days, the licence may be permanently revoked. An appeal to the decision of AERS may be filed with the Ministry of Mining and Energy. It should be noted that apart from the activity of supply, all other gas activities are declared as activities of general interest and may be performed either by public, state-owned companies or by privately owned companies which are specifically authorised by the Government of Serbia to perform a specific activity of general interest pursuant to the Law on Public Companies or the Law on Public Private Partnerships and Concessions.

Exploration and production

(a) Exploration
Exploration for natural gas in Serbia is regulated by the Law on Mining and Geological Explorations (*Zakon o rudarstvu i geološkim istraživanjima*, Official Gazette of Republic of Serbia, No. 101/2015 and 95/2018), while the principle regulatory body in this domain is the Ministry. The law distinguishes between fundamental and specific explorations. Fundamental explorations are performed by the Geological Survey Institute, now a part of the Ministry, whereas specific explorations may be performed by companies registered in the respective commercial registry for the activity of geological explorations and employing an adequate number of geological professionals. Prior to commencement of geological explorations, the appropriate geological project and exploration elaborates must be prepared, both of which are, generally, subject to mandatory technical review, and Exploration Approval must be obtained from the Ministry. The Exploration Approval determines, *inter alia*, the minimum amount of exploration works, validity period, deadline for commencement with the exploration works, reporting obligation, termination grounds.

(b) Production
The production of natural gas is also within the regulatory scope of the Ministry. Natural gas production (i.e. exploitation) is performed by the companies registered with the competent commercial registry for mining activities. Gas production is based on permits issued by the Ministry.

Namely, the following permits are required:
- Exploitation Approval (for the purpose of natural gas exploitation and its refinement);
- Approval for Exploitation Field (for the purpose of natural gas exploitation);
- Approval for Performance of Mining Works (for the purpose of drilling gas wells and gas wells operation);
- Approval for Construction of Mining Facilities (for the purpose of development of the necessary infrastructure); and
- Approval for Operation of the Mining Facilities (for the purpose of development of the gas wells).

An exploitation fee of the natural gas, in the amount of seven per cent of the income earned from exploitation of the natural gas, is paid to the Republic of Serbia.

Transmission and access to the system

(a) General
The Serbian Gas Transmission System ("GTS") is comprised of gas pipelines with a total length of 2,230.00 km and a pressure from 16 up to 50 bars. Serbia has two Gas Transmission System Operators: the public company "Srbijagas" and "Yugorosgaz - Transport" (the "GTSO"). GTS Rules have been adopted by "Srbijagas" and "Yugorosgaz-Transport" and approved by AERS in 2013 and 2015, respectively.

In addition to GTS operations, the GTSO is also, among other duties, responsible for the organisation and management of the gas market, system balancing, purchasing of gas for balancing and adoption of the decision on access prices.

(b) Access to the GTS
(c) According to the Law on Energy, access

to the GTS is granted by the GTSO via connection approval. The connection approval especially contains the connection point, technical conditions for connection, approved capacity, place and manner of measurement, connection deadline and connection costs. The connection approval is issued as part of the procedure for issuance of construction permit for the facility. The GTSO and the interested party enter in an access agreement which regulates the rights and obligations of the parties with respect to access to the GTS. The GTSO is obliged to connect the facility to the GTS within eight days upon fulfillment of the conditions from the connection approval provided that the construction permit for the facility has been obtained and the balancing responsibility regulated. Connection of the producer to the GTSO under the same conditions except that instead of the construction permit the production facility must have the operational permit issued.

The right to utilise the transport capacities of the GTS is regulated by the gas transportation agreement entered into between the GTSO and the customer. This agreement may be a long-term (over one year) or short-term agreement (less than one year) and the agreed capacity may be a cut-off or constant capacity. Access prices are regulated prices determined by the GTSO and approved by AERS. The methodologies for determining access prices are prescribed and adopted by AERS. GTSO is entitled to reject access to the system for the following technical reasons: (i) transportation under-capacity; (ii) if access would endanger the stability of gas supply; or (iii) severe economic and financial difficulties caused due to the take or pay obligations (upon the request of the supplier that has entered into the take or pay gas supply agreement).

(d) Exemption from the obligation to provide access

Major new gas infrastructure, interconnectors and storage facilities, may, upon request, be exempted, from the obligation to provide access under the following conditions:

- The investment must enhance competition in gas supply and enhance security of supply;
- The level of risk attached to the investment must be such that the investment would not take place unless an exemption was granted;
- The infrastructure must be owned by a natural or legal person, independent of the system operators in whose systems that infrastructure will be built;
- Charges must be levied on users of that infrastructure; and
- The exemption must not be detrimental to competition or the effective functioning of the internal market in natural gas, or the efficient functioning of the regulated system to which the infrastructure is connected.

Exemption is granted by a resolution of AERS upon obtaining opinion of the Ministry of Mining and Energy. Additionally, the supplier of natural gas is also entitled to request from the Ministry to exempt the GTSO from the obligation to grant access to the system in the event that it envisages severe financial and economic difficulties due to undertaken take or pay obligations.

Trading and supply

The trading and supply of natural gas is performed on the free gas market. As mentioned above, as of 1 January 2015 only the households and small gas consumers are entitled to public supply under regulated prices. Gas is supplied and traded on the market based on gas purchase agreements. The amount of natural gas contracted under the gas purchase agreement may be pre-agreed for a specific period or determined based on consumer consumption, in the event of gas purchase agreements with full supply. The new Law on Energy also prescribes for "take or pay" gas purchase agreements.

According to the Law on Energy, participants to the free natural gas market may be: (i) natural gas producer; (ii) supplier; (iii) public supplier (i.e. Srbijagas); (iv) end consumers; and (v) GTSO, storage operator and gas distribution system operator (but only for the purpose of its own consumption and balancing due until the unbundling principle is introduced). All participants are obliged to regulate their balance responsibility by entering into balancing services agreements with the GTSO.

7.10.5 Upstream and the oil market

Market overview

One of the sectors which make up the energy economy of Serbia is the oil sector. There is exploitation of domestic oil reserves, as well as the import, transport and processing of crude oil and oil derivatives, and distribution and sales/ export of oil derivatives.

Regulatory overview

Oil-related activities in Serbia are governed by the Law on Energy and the Law on Mining and Geological Explorations. The principle regulatory body in this domain is the Ministry and the AERS which issues licences for carrying out the energy activities in the sector. In addition, AERS keeps a register of issued and revoked licences.

Exploration and production

(a) Exploration
Exploration of oil may be performed by companies registered in the respective commercial registry for the activity of geological explorations and which employ a sufficient number of geological professionals. Prior to commencement of geological explorations, the main geological design and exploration elaborates must be prepared. These documents are subject to mandatory technical review, whereupon Exploration Approval must be obtained from the Ministry Mining and Energy.

(b) Production
The production of oil is also within the regulatory scope of the Ministry of Mining and Energy. Oil production is based on a licence issued by the Ministry in the course of regular administrative procedure. The fee for exploitation of oil paid to the Republic of Serbia amounts to seven per cent of the income earned from the exploitation of oil.

Other oil-related activities

For the performance of other oil-related activities a licence issued by AERS is a prerequisite. The procedure for the issuance of these licences is identical to the procedure for the issuance of licences in the electricity sector. Energy companies (legal entity or entrepreneur registered to perform one or more energy activities) can apply for a licence to perform the following activities:
(a) The production of oil derivatives;
(b) Oil transport by oil pipelines;
(c) The transportation of oil derivatives;
(d) The storage of oil and oil derivatives;
(e) Trade with oil and oil derivatives; and
(f) Retail of oil derivatives (fuel supply stations for motor vehicles).

7.10.6 Impact of the coronavirus pandemic on the energy and infrastructure[57]

Serbia declared a state of emergency on 15 March 2020 for a period of up to 90 days with a possibility of further extension. A number of measures have been imposed on citizens and businesses with the aim of curbing further spread of Covid-19. In parallel, the Government of Serbia started with the preparation of a set of incentive measures to counter the negative impact on the economy. Below is the overview of the announced support measures – note, however, that the support measures described in section "Stimulus Package" have still not been formally enacted.

A. Covid-19 Response Investment and Support Initiative – General

I. Stimulus package

The stimulus package is supposed to apply to the companies which have not reduced their work force for more than 10% during the

[57] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

state of emergency. Below is a summary of the intended measures:

I.1 Tax (fiscal):

- moratorium on payroll tax and social security contributions during the state of emergency, repayment in 24 instalments starting in 2021;
- deferral of advances for corporate income tax payment due in the second quarter;
- VAT relief on donations during Covid-19 crisis.

I.2 Direct aid measures

- three net minimal wages per employee to entrepreneurs and SMEs (first payment expected in mid-May);
- 50% of the net minimal wage to large companies during the state of emergency for each employee sent on forced paid leave during the state of emergency.

I.3 Measures for maintenance of liquidity

- subsidized working capital loans to entrepreneurs, SMEs, registered agricultural households and registered cooperatives, through the Development Fund of the Republic of Serbia;
- guarantees for banking loans to entrepreneurs, SMEs and agricultural households.

I.4 Other measures

- EUR 100 to each adult citizen.

II. Other financial measures and relief

II.1 Moratorium on loan and financial leasing repayment:

The National Bank of Serbia imposed a moratorium on payment obligations of corporate and retail borrowers and payment obligations of corporate and retail debtors under financial leasing contracts. The moratorium will last for the duration of the state of emergency but not less than 90 days starting from expiration of 10 days from publishing the notification on the website. During the moratorium, the borrowers/ financial lessees will be excused from their payment obligations and the banks/financial lessors will not be allowed to calculate default interest on due amounts or initiate judicial proceedings with the aim of collecting their claims. The relevant wording does not restrict moratorium to payments that fall due during the moratorium, so it seems the moratorium extends to amounts that became due and payable prior to its introduction.

The moratorium is for the benefit of the borrowers/financial lessees. Those who wish to continue to settle their repayment obligations during the moratorium will be naturally allowed to do so. Banks/ financial leasing providers are obliged to publish a moratorium offer on their respective websites until 21 March 2020, and such publication will be deemed notice to all affected borrowers/lessees. The borrowers/ lessees who reject the offer within ten days from its publication will be obliged to continue to settle their debts notwithstanding the moratorium, while those who remain silent will be deemed to have accepted the offer to benefit from the moratorium.

II.2 Other measures:

- National Bank of Serbia reduced the reference interest rate to 1.75%.
- one-off aid in the amount of RSD 4,000 (approximately EUR 34) to retirees;
- interest-free three-month moratorium on payment of utility bills for retirees;
- 10% salary increase for the healthcare sector starting from 1 April 2020;
- moratorium on enforcement and interest calculation on tax debt under re-programme;
- interest on tax debt reduced to an annual reference interest rate of the National Bank of Serbia (normally, the interest rate is equal to the NBS reference rate plus 10 percentage points);
- During the state of emergency, the Deposit Insurance Agency may invest foreign exchange assets it manages into securities issued by the Republic of Serbia without limitation (normally, it cannot invest more than 1/4 of its assets into the state paper).

B. Impact on the Energy and Infrastructure Sectors

The major development in the Serbian energy sector arising from the Covid-19 outbreak is the suspension of all renewable energy PPAs by the off-taker, state-owned utility EPS. In its force majeure letter sent to all renewable energy producers included in the feed-in tariff system, EPS alleges that the pandemic and the state of emergency declared in response to the pandemic amount to a force majeure event that prevents it from fulfilment of its obligations under the PPAs, i.e. from payment of the feed-in tariff. As a replacement, EPS offered a short-term offtake agreement with purchase price amounting to approximately one-third of a price under the feed-in tariff regime, and that would apply during the state of emergency. The FM notices do not provide any substantiating evidence of EPS being objectively prevented from fulfilling its obligations, so we may expect that the renewable energy producers will challenge the EPS's actions and seek compensation.

The economic downturn will have obvious and severe consequences on the energy sector. The price on the Serbian power exchange SEEPEX fell for around 50% compared to March 2019 with the trading volumes remaining roughly the same. As a result of the need to finance the stimulus package, it seems that the Government will have to look into the viability of certain infrastructure projects, primarily road infrastructure financed from the budget, although there is still no official information in that respect. It is possible that the need to reallocate budgetary resources to other purposes will incentivise the Government to try to develop these projects through concession or PPP arrangements or even monetize on the recently developed road infrastructure. The development of ongoing infrastructure projects is affected by the closure of borders and restrictions on the movement of people. Contractors are raising force majeure notices with their employers but the actual scope of inability to perform and potential delays are still hard to determine.

International airports in Belgrade and Niš are closed for commercial traffic. The airports will still be open for cargo and mail transport, search and rescue, humanitarian flights, emergency medical transport, technical landing and positioning of Serbian aircrafts, emergency landing of aircrafts, state aircrafts and special purpose flights.

7.11 SLOVENIA

7.11.1 Introduction to the energy market

In recent years, Slovenian energy sector has been continuously developing and adjusting to changes and challenges of international energy trends. Positioned on important European energy crossroads, it is essential for Slovenian energy markets and their actors to be responsive and reliable. This is reflected in increased use of renewable energy, which is gradually replacing conventional fossil fuels, higher energy efficiency and increasingly demanding end-customers, which have themselves also been becoming producers, some even self-sufficient. Transition from conventional fossil fuels to renewable energy requires development and implementation of smart grids which ensure the necessary flexibility of the market and enable active participation to all actors on the market – producers, traders and end-customers. In 2017, there were 16 smart grids and other new technologies projects included in a special incentive scheme in Slovenia, two of which were the result of domestic partnerships and 14 were international projects.

The umbrella act regulating energy sector in Slovenia is the Energy Act (Official Gazette of the Republic of Slovenia No. 17/2014, as amended; the "**Energy Act**") which transposed into Slovenian legislation the EU's Third Energy Package. The Energy Act entered into force on 22 March 2014 and significantly amended the legal regulation of the energy sector. It follows the principles of protection of the customers, competitiveness, transparency, non-discrimination and independency of the regulator and has introduced the regulation of the energy sector in a more systematic and transparent way. A significant number of new implementing acts (rules, regulations and similar) have also been (and some of them are still envisaged to be) adopted on the basis of the Energy Act.

The Energy Act was amended in November 2015 due to implementation of the Out-of-Court Resolution of Consumer Disputes

Act which was adopted on the basis of the transposition of Directive 2013/11/EU into Slovenian legislation. In addition, two important amendments to the Energy Act are envisaged to be adopted in the near future.

In addition to the Energy Act and implementing regulations, the Slovenian energy sector is governed also by the Environment Protection Act (Official Gazette of the Republic of Slovenia No. 41/2004, as amended), Construction Act (Official Gazette of the Republic of Slovenia No. 61/2017, as amended) and Spatial Planning Act (Official Gazette of the Republic of Slovenia No. 61/17) also apply.

The Energy Concept of Slovenia is the basic development document, representing the national energy program. It has been recently prepared by the government and presented to the National Assembly which shall presumably adopt it by the end of 2019.

7.11.2 Electricity

Market overview

Slovenia has opted for the complete liberalisation of the electricity market. Hence, the activities of electricity production and supply are carried out freely, meaning that the market players may freely negotiate prices and quantity of supplied electricity, the end consumers may freely choose and change their electricity suppliers and the producers may freely choose and change the supplier, supplying the electricity they had generated, to the end consumers. The organisation of the market, as well as the activities of the transmission system operator and the activities of the distribution system operator are carried out as mandatory national public service.

The key market players in Slovenia are Elektro – Slovenija, d.o.o. ("**ELES, d.o.o.**") – transmission system operator, SODO, d.o.o. – distribution system operator, Borzen, d.o.o. – electricity market organizer, several distribution network operators (such as Elektro Ljubljana d.d., Elektro Primorska d.d., Elektro Maribor d.d. and Elektro Gorenjska d.d.) and several electricity suppliers (such as Elektro Energija d.o.o., ECE d.o.o., Elektro Maribor Energija Plus d.o.o., E3 d.o.o., GEN-I d.o.o., Petrol d.d., RWE Ljubjana d.o.o.). With the exception of electricity sale where private entities (such as RWE) have been entering the Slovenian market, most of key market players are still directly or indirectly state-controlled.

The first pillar of the Slovenian wholesale electricity market comprises the holding company Holding Slovenske elektrarne, d.o.o. ("**HSE**") which operates the Drava Hydroelectric Power Plant, the Soča Hydroelectric Power Plant, the Šoštanj Thermoelectric Power Plant, the Trbovlje Thermoelectric Power Plant and (together with GEN Energija, d.o.o.) the Lower Sava- and the Middle Sava Hydroelectric Power Plants. The second energy pillar is the group GEN energija, d.o.o. ("**GEN energija**"), operating the Brestanica Thermoelectric Power Plant and the Krško Nuclear Power plant, as well as the Sava Hydroelectric Power Plants and (together with HSE) the Lower Sava Hydroelectric Power Plants. Moreover, GEN energija operates also several Renewable energy sources throughout Slovenia.

Regulatory overview

Energy Act systematically regulates the electricity sector by determining the electricity-related activities falling within the scope of regulation, i.e. electricity production, electricity supply, activities of system operator, activities of distribution operator and activities of the electricity market operator. Contrary to the past legislation, it is according to the Energy Act no longer necessary to obtain a licence for carrying out electricity-related activities.

The electricity sector is (in addition to natural gas and, to a certain extent, district heating) regulated and supervised by the Energy Agency of the Republic of Slovenia ("**Energy Agency**").

On the other hand, the Directorate for Energy, operating within the competent ministry (currently the Ministry of Infrastructure), *inter* *alia*, supervises the operations of the public utilities services in the field of electricity (as well as natural gas and district heating) and plans the extent of issued concessions and energy permits (applicable to the construction and operation of energy facilities) by way of maintaining the corresponding register. Its Division for a Low-Carbon Society carries out several tasks (such as preparing the national legislation and the calls for tenders for co-financing of investment projects) relating to renewable sources of energy and to sustainable use of energy sources.

Generation

Pursuant to the Energy Act an energy permit is required for the construction of energy generation facilities, provided that the effective rated electricity capacity exceeds 1 MW and that it is connected to the public network. The energy permit is issued by the ministry competent for energy. The energy permit must be also obtained for each reconstruction of the facility.

If the scope of the electricity generation capacities does not ensure the secure electricity supply, and if the secure electricity supply cannot be ensured by way of energy efficiency measures, the ministry competent for energy (or the electricity market operator on its behalf) may organise a call for tenders for new generation facilities or for the implementation of the energy efficiency measures. The call for tenders shall be published in the Official Gazette of the Republic of Slovenia and in the Official Journal of the European Union, whereby the deadline for the submission of bids may not be less than six months. The bidder may – instead of a new production capacity – also offer to supply the electricity from existing production capacities, if the long-term outcome, identical security of the supply and the environmental suitability of the electricity generation are ensured.

The predominant share of generation in Slovenia is carried out in conventional power plants, such as thermoelectric power plants, hydroelectric power plants and the nuclear power plant which presented approximately 97 per cent of the generation in 2017.

Hydroelectric power plants and power plants using other renewable sources generated around 30 per cent of all electricity generation in 2017. In particular, Slovenia relies heavily (around 27 per cent of all electricity generation) on hydroelectric power plants. Thus, the share of electricity generated by hydroelectric power plants can fluctuate significantly due to its dependence on hydrological and weather conditions. Power plants operating with fossil fuels contributed around 30 per cent and the nuclear power plant around 40 per cent of all electricity generation.

Apart from the production in large power plants, the Slovenian electricity system also includes some distributed production, mainly in small hydroelectric power plants, solar power plants, biogas power plants and industrial facilities for the cogeneration of heat and electricity.

The new Regulation on self-supply with electricity from renewable energy sources (Official Gazette of the Republic of Slovenia No. 17/19), which was adopted on 21 March 2019 and enters into force in the beginning of May 2019, replaces the previously valid Regulation, regulating electricity self-supply, and further promotes the use of electricity from renewables for the total or partial coverage of own electricity consumption. The Regulation defines the conditions for self-supply of electricity from renewables, the accounting method, the annual limitation of power for power plants, the reporting requirements and the manner for calculating produced electricity. It introduces three different types of self-supply with electricity from renewable energy sources, namely (i) individual self-supply; (ii) self-supply of multi-apartment buildings; and (iii) self-supply of communities of consumers. Compared to the previously valid Regulation, which only allowed self-supply of individual one-dwelling residential houses and business buildings, the new one enables self-supply to a broader variety of subjects and thus further encourages generation of electricity from renewable energy sources.

Trading and supply of electricity

The Slovenian electricity market is completely liberalised, fully opened and divided into the wholesale market and the retail market. The activity of the electricity market operator is carried out as a national public service obligation.

Pursuant to the Energy Act electricity market is hierarchically regulated into a balance scheme, in which the relationships between the balance scheme members are uniformly determined by the agreements on balance sheet membership. Transactions among the balance sheet members may either base on the quantity of supplied electricity in a relevant time frame, determined for each accounting interval (closed contracts) or determine the balancing affiliation of delivery points (open contracts). Closed contracts may be entered into only between two balance scheme members, save as closed contracts with the use of cross-border transfer capacity, in case of which one of the parties is the balance scheme member and the other party is a foreign market participant. Open contracts may be entered into only between a balance scheme member and a legal entity or natural person, entitled to enter into an open contract for a delivery point in Slovenia, which is the object of the contract. In case of open contracts and closed contracts with the use of cross-border transfer capacity the same legal entity or natural person may act on both sides.

New Rules on the Electricity Market Operation entered into force on 1 January 2019 and regulate, *inter alia*, the process of balance group and subgroup establishment, as well as recording of contracts and imbalance settlement. The main changes introduced by the new Rules are among others: shorter accounting period - from the current length of 1 hour the accounting period is reduced to 15 minutes, whereby this change shall enter into force only in 2020; obligation of balancing service providers to become members of the balance scheme; different dispute resolution approach in case two market actors disagree on the quantity of the electricity of a notified closed contract; if the market actors do not find an agreement, the market operator does not accept the application of the contract or the application is ignored and a quantity equal to zero is taken into account etc. Furthermore, Rules Amending the Rules on the Balancing of the Electricity Market entered into force on 17 June 2017.

The market players trade on the electricity market are as follows: (i) the producer: sells in its own name on the basis of an open contract; (ii) the end user: buys in its own name on the basis of an open contract; (iii) the supplier to the system users: sells to end users or buys from the producers on the basis of an open contract; and (iv) the trader: sells and buys electricity on the basis of a closed contract. An individual natural person or a legal entity may simultaneously trade with electricity in different above described roles.

The market operator may prohibit or limit inclusion into the balance scheme due to the reciprocity. It may decide that the right to be included in the balance scheme shall not be granted to a legal entity residing in a state where all the customers don't have the right on free choice of the supplier.

A part of the electricity market is the mandatory balancing market, the aim of which is settling electricity system imbalances in a transparent and economically efficient manner. The producers and the consumers are obliged to participate on the balancing market with respect to the technical parameters of their facilities and other relevant characteristics and circumstances. The balancing market is embedded in the Intraday Continuous Market (see below for more details) in which the Transmission System Operator (ELES d.o.o.) buys and sells electricity for the settlement of imbalances in the electricity system. For trading on the Balancing market the same rules as for the Intraday market apply.

BSP Energy Exchange (BSP Energetska Borza d.o.o.) offers a trading platform for Day-ahead and Intraday trading. Intraday market is further separated to Intraday Continuous Market and

Intraday Auction Market, which was introduced on 21 June 2016 and allows members to trade remaining cross zonal capacities from Day-ahead auction. Intra-day trading is performed 24 hours per day by placing anonymous bids for standardized and other products through online application. Day-ahead market is through the borders with Italy, Croatia and Austria included in the Multi Regional Coupling. Trading is performed through auction for standardized hourly products in several phases: (i) trading phase; (ii) stagnation phase; (iii) after-trading phase; and (iv) inactive phase. In addition, BSP Energy Exchange established itself also as a regional long-term auction centre.

Cross-border trading with electricity includes exports from Slovenia, imports to Slovenia, and transit through the territory of the Republic of Slovenia. For the cross-border trading EU legislation applies.

In addition to the conventional electricity markets, the Slovenian company SunContract introduced an alternative option for smaller producers and end-consumers. Since 2018, the company offers a global peer-to-peer trading platform which enables individual participants to directly trade electricity with each other. The platform based on blockchain technology is still small and insignificant compared to conventional markets; however, it might indicate future development of electricity trading and supply.

Transmission and grid access

The activity of the transmission system operator is a national public utility service obligation, which is carried out by a legal entity or natural person on the basis of concession, granted by the State. The concession is granted for the entire territory of the Republic of Slovenia for a maximum period of 50 years and is not payable. The concession operator must fulfil the following conditions: (i) is the owner of a transmission system; (ii) is certified for the system operator (the certificate is issued by the Energy Agency); and (iii) has been appointed for the system operator. Currently, the function of transmission system operator is carried out by ELES, d.o.o. The activity of transmission system operator is financed through payments of network tariffs and other incomes for carrying out a national public utility service.

Access to the Slovenian grid is regulated by means of a regulated third-party access and is legally and in practice available to all network users. Persons wishing to become system users or electricity operators may be connected to the system pursuant to the system operation instructions. An application for network access has to be submitted to the transmission network operator or to the distribution networks operators, which decide about the application by issuance of the consent to connection. The consent to connection is valid for two years, meaning that all conditions have to be met and the connection has to be made within this deadline. The consent to connection determines the scope of right on system use by determining the maximum connecting power or other operating restrictions. Under certain conditions (which are explicitly set out by the Energy Act) the consent to connection is transferable. Prior to the connection to the system the system user and the network operator have to enter into an agreement on the system use.

The access to the grid to a potential system user may be refused due to lack of capacities or if the requested connection would disable the performance of activities of the transmission system operator or of the distribution system as a public service obligation. If the request for connection is rejected due to the lack of capacities, the system operator has to extend the system, provided that this would be economical or that the requesting person is willing to pay the costs of extension.

In addition to other payments, the system users are periodically paying network fees for individual connection, i.e. transmission network fee, distribution network fee, connection power fee and the acquired excessive reactive energy fee. The network fees are set by the Energy Agency in form of tariffs.

In the recent years, the main focus has been on new technologies and development and implementation of smart grids, which are necessary – with the increasing number of electricity producers, end-users and those market participants who act both as producers and end-users – to ensure cost-effective, sustainable, reliable and frictionless communication and exchange between the market actors. For this purpose, Energy Agency initiated in 2013 and even more so in 2016 an incentive scheme for two types of projects:

(a) Pilot projects are projects aimed at testing of already established technologies that are not yet present in Slovenia. Regulatory incentives for this type of projects are limited in content and time, and are intended primarily to eliminate regulatory barriers for the implementation of such projects.

(b) Investment projects include projects for introduction of new technologies into operation of the electro-energy system with the aim of effectively resolving certain network operation issues, such as neutralization of the negative effects of integrating renewable sources of electricity, lowering peak loads, promoting energy efficiency, etc. Investment project are incentivized with direct financial incentives for funds that are activated under these projects.

7.11.3 Renewable energy

Market overview

The share of energy from renewable sources in gross final energy consumption is slowly increasing and in 2017 amounted to approximately 22 per cent. To attain the long-term targets by 2020, i.e. 25 per cent of gross final energy generation from renewables, set out under the Renewable Energy Directive, in 2017 the government prepared an amended Action plan for renewable sources of energy 2010-2020, introduced several new measures and renewed the already existing incentives. The major renewable energy source is wood biomass, in particular with respect to heating, followed by hydropower. In recent years, the dynamic in the electricity generation is also the development of solar energy and wind power energy. Also, with respect to geothermal energy there is – due to high costs of the exploration and uncertainty of its outcome and thus lack of potential investors on this area – still a lot of room for improvements.

Several tasks in relation to renewables (such as preparing the national legislation and the calls for tenders for co-financing of investment projects) are carried out by the Directorate for Energy, Division for a Low-Carbon Society, organized within the Ministry of Infrastructure.

Support schemes

The support scheme for production of electricity from renewable energy sources and in co-generation installations is intended to incentivize investments in environmentally friendly technologies for generation of electricity and has in recent years been considered as the one of the most important measures of Slovenian climate-energy policy. Due to coordination of the rules and conditions of the support scheme with the European Commission, the new support scheme entered into force at the end of 2016. After the notification, procedure was successfully completed by the European Commission in October 2016 and the scheme was declared compatible with the internal market.

The operation, the organizational structure of the support scheme and the responsibilities and tasks of the institutions responsible for the operation of the scheme, which are the Energy Agency and the Centre for Supports, operating within the electricity market organizer - Borzen d.o.o., are regulated by the Decree on support for electricity generated from renewable energy sources and from high-efficiency cogeneration (Official Gazette of the Republic of Slovenia, No. 74/16).

According to the Energy Act the support schemes are intended for generating facilities on renewable energy sources, not exceeding 10 MW of nominal electric power (50 MW in case of facilities, using wind energy) and for production facilities with high efficiency cogeneration not exceeding 20 MW of nominal electric power, that have been chosen on the basis of a public call of the Energy Agency. The supports may be exercised as (i) guaranteed purchase of generated electricity, supplied in the public electricity energy network at a price determined by the Government (provided that the nominal electric power of the generating facility is below 0.5 MW); or (ii) as financial aid for current business (for all other producers). An individual support may be provided: (i) for new high efficiency cogeneration facilities for 10 years; (ii) for new facilities for renewable sources energy for 15 years; and (iii) for older facilities also for a shorter period of time that represents the difference between actual age of the facility and the above stated maximum period of support. The support may be granted only for the generated energy for which a valid origin certificate has been submitted.

The origin certificate is an electronic document, issued by the Energy Agency, which enables the producers and the suppliers to prove that the electricity has been generated in high efficiency cogeneration or from renewable sources as the case may be. The origin certificate may only be obtained for the electricity, generated in an electricity generating facility, holding a valid declaration (issued by the Energy Agency for a definite period of time).

In order to receive support, an owner or leaseholder producing or intending to produce electricity from renewable energy sources must first obtain from the Energy Agency the confirmation of the project and within maximum three years after the confirmation of the project (five years in case of more complex facilities) the declaration for the electricity generating facility (also issued by the Energy Agency), which represents the basis for issuance of the decision on granting of the support.

After being granted a final decision for support, a producer shall enter into a contract for the provision of support with the Centre for Support at Borzen d.o.o., the electricity-market operator, to which the implementation of the support scheme has been entrusted. The contract shall regulate all issues regarding mutual obligations of the contractual parties.

The Energy Agency ensures that the system is not misused by multiple sales of a certain amount of electricity as environmental-friendly electricity. The system is designed in such a way that it assigns added value to the electricity produced in an environmental-friendly way. It allows suppliers to acquire environmentally-friendly products in a transparent manner and consequently enables customers to choose electricity with regard to its source or manner of production.

Important support is provided also through Eko Sklad (Eco Fund), a public fund which finances investments by awarding grants and granting loans under more favourable conditions in the area of environmental protection in accordance with the National Environmental Protection Program. Such grants or loans may be granted to legal entities or natural persons. Natural persons may be granted a loan or awarded a grant for, amongst others, financing the use of energy from renewable sources, while legal entities may be financed for the facilities in which the energy from renewable sources shall be produced. In June of 2019, Eco Fund published the latest public call for 3.6 million of non-reimbursable financial inducement for renovation and investment into older buildings with three or more individual parts. Compared to previous public calls, this one broadens the range of subjects and buildings that are eligible for the available funds, making them even more accessible.

7.11.4 Natural gas

Market overview

Slovenia has a negligible degree of natural gas production and entirely depends on supply of natural gas from abroad. In 2017, approximately 75 per cent of natural gas was supplied from Austria; the original source of this gas is unknown, but it is most likely to be of Russian origin. Approximately 23 per cent of natural gas was supplied from Russia, and some smaller amounts were supplied from Italy, Croatia and other locations.

Natural gas consumption is slowly increasing each year since 2014 and has amounted to 9.677 GWh of energy in 2017. Similarly, the number of natural gas importers also increased to 28 in 2017 (six new compared to 2016). The gas is supplied to end users from 80 Slovenian municipalities in its gaseous state via transmission and distribution networks managed and operated by the system operators. Transmission and distribution companies have their commercial and regulated energy activities separated and thus help facilitate the natural gas market. The commercial activity of the distribution companies is the supply of natural gas and their regulated activity is the distribution of natural gas over the distribution networks.

The market players on the Slovenian natural gas market lle traders and suppliers lh deliver natural gas to customers. The key market players are the major supplier of natural gas Geoplin, d.o.o. and its subsidiary Plinovodi d.o.o. – the transmission network operator. The distribution system operators are divided between different parts of Slovenia, some of the major ones are Energetika Ljubljana d.o.o., Plinarna Maribor d.o.o. and Adriaplin d.o.o. (a subsidiary of ENI). The natural gas distribution is carried out as an optional municipal public utility service through a public company established by the municipality, on the basis of a concession agreement or through a public-private partnership.

Regulatory overview

Energy-related activities relating to natural gas are supervised by the Energy Agency. In addition to the Energy Act, a new Decree on the operation of the natural gas market entered into force at the end of 2016 which in more detail regulates the relationships between the market participants and certain procedures necessary for smooth operation of the natural gas market, and introduced a new accounting unit (i.e. kWh or MWh) for easier comparison with costs of other energy sources. According to the Energy Act no licence is required for performance of activities in relation to the supply, trading and transport of natural gas.

Transmission and access to the system

Since January 2005, the activities of the transmission system operator have been carried out by Plinovodi d.o.o.. The respective operator operates a 1.121 km long transmission network forming a part of the European network. Due to Slovenia's beneficial geographical position the network is connected with the networks in Italy, Austria and Croatia.

The activity of the transmission system operator is a national public utility service obligation. It is carried out by the transmission system operator on the basis of obtained concession. The concession is granted by the Republic of Slovenia to the transmission system operator as the concessionaire for the entire territory of the Republic of Slovenia for a maximum period of 35 years.

Access to the Slovenian network is regulated by means of regulated third party access and is legally and in practice available to all network users. The transmission system operator grants the access to the transmission system by entering into agreements on transmission on the entry and exit points of the transmission system. The transmission system users may enter into a separate transfer agreement for one or several entry points or – as the case may be – into a separate transfer agreement for one or several exit points from the transmission system. The individual agreements entered into for the entry- or exit points may be concluded for different transmission capacities and for different time-frames. The agreements on transmission on the exit points of the transmission system in the Republic of Slovenia, to which the end users are directly connected, are concluded by the end users or by the natural gas suppliers on behalf of the end users. It is considered that all transactions with natural gas – irrespective to their entry or exit point – are entered into in the virtual point, established by the transmission system operator. Transmission agreements for exit points inside the Republic of Slovenia have to be brought into in line with the System operating instructions for natural gas transmission (Official Gazette of the Republic of Slovenia, No. 55/15 as amended) which apply to all legal relationships relating to the transmission system owned by Plinovodi d.o.o. as the transmission system operator. Moreover, the Rules on the procedure for the allocation of the capacity of the transmission system for the entry and exit points within the Republic of Slovenia, the transmission system congestion management procedure and the capacity trading on the secondary market (Official Gazette of the Republic of Slovenia, No. 80/14 as amended) regulate the system of entry-exit points, the procedures for the allocation of transmission system capacities for the entry and exit points within the Republic of Slovenia, short-term services for the entry and exit points in the Republic of Slovenia offered by the transmission system operator, secondary market capacity trading at the border entry and border exit points, the congestion management procedures in the event of contractual congestion and the publication of information. The capacity allocation procedures at the border entry and exit points of the transmission system on the primary market are regulated by the transmission system operator's general act on terms and conditions, as well as the capacity allocation mechanisms at interconnection points of the transmission system through auction. The secondary market capacities can be traded at the border entry and border exit points.

The system users are obliged to pay the expenses for use of the natural gas system in the form of the network charge. The network charge is – within the regulative frame – determined by the system operator upon previous consent of the Energy Agency. The collected network charges are used for coverage of the expenses incurred by the system operator with respect to maintenance, management and development of the system.

The system operator may deny the grid access to a potential user only in case of insufficient capabilities or if the connection prevented the performance of public utility service obligations or due to serious economic and financial troubles of the companies in the field of gas economy in connection with the contracts "take it or pay it". The reasons for denial must be grounded. If the access to the grid was denied due to insufficient capacities, the system operator is obliged to extend the system, provided that this would be economical or if the denied person is willing to bear the costs of such extension.

In addition, the Regulation (EC) No. 715/2009 of the European Parliament and of the Council applies directly and determines fair rules with respect to access of the transmission networks concerning non-discriminatory conditions for access to transmission systems and facilities and storages of liquefied natural gas.

The activity of distribution system operator is an optional local public utility service. The performance of the public utility service of distribution system operator may be assured by the local community on its entire territory or on a part thereof, in the manner, set out by the legislation, regulating public utility services and the public-private partnership. The activities of the distribution system operator are financed from the network charges and other incomes for financing of the public utility services.

The local community may grant the right on performance of the optional local public utility service of the distribution system operator as an exclusive right for a period of maximum 35 years. If such exclusive right is granted, as a rule, only the distribution system operator, to which such exclusive right was granted, is entitled to connect the end users to the distribution system in its area.

Distribution may also be carried out in closed distribution systems. In such case the distribution is not carried out as a local public utility service. Closed systems are intended for natural gas distribution on geographically rounded industrial or commercial areas and are, as a rule, not intended for the supply of the consumers. The status of closed distribution system is granted by the Energy Agency, if (i) due to particular technical and safety reasons the operations and production processes of end users of such system are integrated; and (ii) if the network is distributing the natural gas in particular (at least 80 per cent of the amount of annually consumed natural gas) to the owner of the system or its affiliated companies.

Trading and supply

According to the Energy Act it is considered that – irrespective to the actual entry or exit point – all transactions with natural gas are affected in the virtual point and on the level of the calculation interval. In this respect the "virtual point" is a virtual point between the entry and exit points of the transmission system, in which it is considered that all transactions with the natural gas quantities in the transmission system between the market participants on the transmission system in the Republic of Slovenia have been entered into. This assumption applies irrespective to provisions of individual natural gas supply agreements. Transaction in virtual point may also be made in the absence of a transmission agreement, if an agreement on transmission on entry point and an agreement on transmission on exit point have been concluded for a quantity that is a subject of the respective transaction, for the calculation period(s) that the transaction relates to.

In accordance with the Energy Act and on its basis adopted System operating instructions for the natural gas transmission network (Official Gazette of the Republic of Slovenia, No. 55/2015), as of October 2015, the transmission system operator has established a virtual trading point for natural gas on the transmission system. The virtual point enables the transmission system operator to monitor the transactions of the market players (e.g. where the natural gas was purchased and to whom it was sold) as well as to monitor whether all natural gas transmitted to Slovenia was used in Slovenia. At the virtual trading point the transmission system operator provides the services for performing transactions with natural gas and a bulletin board for natural gas trading. Services in the virtual trading point are provided to members only on the basis of concluded virtual point membership contracts. Operations regarding balancing the transmission system shall also be carried out by the transmission system operator via the virtual trading point. The transmission system operator has also established an electronic trading platform as a special feature of the virtual trading point enabling the transmission system operator and the balancing group leaders to provide balancing of deviations related services.

Since implementation of the open market and the virtual trading point in October 2015 and the first transactions thereof in January 2016, the trading on the open market has been well accepted by the market participants. In the second half of 2017, the trading volume increased significantly, resulting in 1,521 performed transactions and approximately 478.8 GWh of exchanged natural gas throughout the entire year.

Companies of gas economy and final customers may exercise a transaction with natural gas quantities in the virtual point, provided that they have registered their participation in the virtual point with the transmission system operator and have reported the desired transaction pursuant to the rules on operation of the virtual point determined in the System operating instructions for the natural gas transmission network. The transmission system operator is obliged to verify the compliance of the envisaged transaction(s) of the companies of gas economy or final customers in accordance with the rules on operation of the virtual point. If the transmission system operator finds out that the chain of transactions of the companies of gas economy or final customers is not completed or could not be reconciled, it rejects all reported transactions in such chain.

Slovenian natural gas transmission system is an integrated part of the European transmission system and has three connections with the neighbouring transmission systems, whereby the connection with Croatia is only an exit point, the connection with Austria is only an entry point and the connection with Italy is both, an entry and an exit point. The natural gas transmission system operator (Plinovodi d.o.o.) provides auction as a method of allocating annual and multi-annual transmission capacities at entry points into and at exit points from the Republic of Slovenia. Capacities at interconnection points of the transmission system are used to ensure the supply of natural gas in Slovenia, as well as for the purposes of the transmission of natural gas to the neighbouring transmission networks. Pursuant to the Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010, each Member State shall ensure that the necessary measures are taken so that in the event of a disruption of the single largest gas infrastructure, the technical capacity of the remaining infrastructure, determined in accordance with the "N – 1 formula" is able to satisfy total gas demand of the calculated area during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. However, by way of exception, Slovenia – due to its specific situation, i.e. lack of liquefied gas and natural gas storage facilities – is not bound by, but has to endeavour to meet, this obligation. In accordance with the Energy Act, the transmission system operator has adopted the Rules on terms and conditions as well as the capacity allocation mechanisms at interconnection points of the transmission system through an auction (Official Gazette of the Republic of Slovenia, No. 67/2014 as amended), on the basis of which the operator has started allocating transmission interconnection capacities through auction. The transmission system operator shall ensure network access at interconnection points by concluding transport contracts on auctioned capacities, separately and independently at border entry and at exit points. The transmission system operator offers standard capacity products at auctions and is for this purpose a part of the online capacity booking platform of major European transmission system operators – PRISMA (European capacity platform, https://platform.prisma-capacity.eu/#/start).

Pursuant to the Decree on functioning of the natural gas market, which entered into force at the end of 2016, natural gas is traded on the open and balancing markets while transfer capacity may be traded on the primary or secondary market. On the open market participants may directly conclude agreements on the supply of natural gas and the supplier and customer may freely determine the price and quantity of the supplied natural gas. All transactions are concluded in the virtual point, which is managed and determined by the transmission system operator. The balancing market is intended for trading with quantities of natural gas, necessary for the balance of differences between the committed quantity at one or more takeover points and committed quantity at one or more delivery points. The transfer capacities market is intended for acquiring the highest possible usage of transferred capacities of natural gas network.

The operation of the market is directed towards balancing the contractual and physical currents in the natural gas network. On the primary market, the transfer system operator sells the rights to transfer capacities to the end users connected to the transmission network and to the operators of the distribution systems. On the secondary market, the participants with the rights of transfer capacities directly trade on the basis of bilateral contracts and the prices are freely determined by the market conditions.

As regards the natural gas trading and the supply agreements, a balance scheme is provided on the market. Transmission system operator shall include in the balance scheme all individuals and legal entities who have concluded a balance agreement with the transmission system operator or have concluded a balancing agreement with the carrier of the balancing group. The membership in the balance scheme is terminated with termination of validity of these agreements. The supplier and the system user enter into the agreement on natural gas supply.

An open agreement with a system user may be entered into only by a supplier that is the balance scheme member.

A user of the natural gas system may form a balance group and become the balance group carrier by concluding a balance agreement with the transmission system operator. Any balance group carrier shall be the carrier of only one balance group and shall be responsible in particular for the announcement of the takeover and transfer of natural gas for the balance group and payment of the calculated quantitative deviations of the balance group. In addition, the balance group carrier shall keep a list of all members of the balance group and the hierarchical list of balancing agreements. Balance scheme members may either be market participants which conclude an open contract with the balance scheme carrier or a balance sub-group if its carrier concludes a balance agreement with the balance group carrier. Save for the market broker, all system users must be members of the balance groups or sub groups.

The natural gas market is completely liberalised and open, meaning that every end user may freely choose the natural gas supplier, irrelevant of the fact in which EU Member State the supplier is established. However, the supplier has to fulfil the requirements concerning the balancing of discrepancies, as well as all other requirements envisaged by the Energy Act. An end user may freely change the supplier by submitting a request to the current supplier which has to undertake all necessary steps to enable the end user to exercise the supply agreement with the new supplier within 21 days as of its request. The supplier must periodically free of charge notify its users on the consumption of natural gas and thus enable the users to freely balance their own consumption.

Consumers are additionally protected by the provisions of the Energy Act, determining the minimum content of the supply agreement (which must be concluded in writing or electronically). A consumer may terminate the supply agreement without being obliged to pay any contractual penalties, indemnity, compensation or any other payment deriving from termination, if the termination becomes valid after one year from the conclusion of the agreement. In any case, a consumer may terminate the contract without notice period in case of choosing another supplier. An integral part of the supply agreement are also general terms and conditions which have to be fair, determined in advance, clear, understandable and may not include any non-contractual barriers for exercise of the consumers' rights (e.g. extensive documentation). The supplier is also prohibited to use unfair and misleading methods of natural gas sale and has to ensure clear information to the consumers. Any changes of general terms and conditions have to be notified to the consumers at least one month before their application. In this context, the Decree on functioning of the natural gas market also obliges the suppliers to use a new accounting unit (i.e. kWh or MWh) to enable the consumers easier comparison with costs of other energy sources.

7.11.5 Upstream and the oil market

Market overview

In Slovenia the exploitation of oil began in 1940 when oil stocks were discovered in the North-East part of the country (Petišovci pri Lendavi). They are the only stocks of oil to have been discovered and they have already been exhausted. An oil transmission network does not yet exist, and Slovenia is therefore completely dependent on the import of oil. The main sources of oil are Algeria and Russia. Oil represents 40 per cent of imported fossil fuels in the total supply of energy in Slovenia.

The key market players in the Slovenian oil market are the suppliers of oil Petrol d.d. and OMV Slovenija d.o.o.. The other suppliers of oil with a minor market share are also MOL Slovenija d.o.o. (which recently acquired several petrol stations in Slovenia, previously owned by the ENI Group), INA Slovenija d.o.o. and Shell Adria d.o.o. (which is supplying only diesel fuel for trucks).

Regulatory overview

Oil is considered a mineral resource and is regulated by the Mining Act (Official Gazette of the Republic of Slovenia No. 61/2010, as amended). In addition, also the Energy Act regulates certain oil-related activities.

The search for mineral resources (including oil) is free. However, exploration may not cause damage to third parties. Prior to the commencement of drilling a borehole depth of 30 m or more, it must be verified that the geological structure does not contain beds of coal or hydrocarbons and that borehole does not exceed 300 m.

Prior to the commencement of exploration in a defined exploration area, an exploration permit must be obtained under the conditions and in accordance with the procedure determined by the Mining Act. Prior to the exploitation of oil, an exploitation concession (which may be granted on the basis of previously obtained mining right for exploitation) must be obtained.

An exploration permit and mining right for exploitation may be granted to a legal entity or a natural person which complies with the following requirements: (i) has its registered seat in (or is a citizen of) a Member State of the EU or EEA, Swiss Confederation or OECD; or (ii) has its registered seat in (or is a citizen of) a third country under the condition of reciprocity. Nonetheless, it is not possible to obtain the permit for the purpose of injection or storage of carbon dioxide.

An exploration permit shall be issued for no more than five years and may not be extended, unless in case of force majeure; in such a case the permit is extended for the duration of the force majeure.

The exploration may begin when the exploration permit becomes final. Prior to exploration, the explorer has to prepare an audited implementation plan for each of the exploration areas. The exploration activities must also be reported to the competent mining inspectorate, the Slovenian Geological Fund and any other body, stipulated by the exploration permit at least 15 days prior to the beginning of the exploration. Any trade with the mineral sources obtained during the exploration is prohibited.

Prior to the conclusion of the concession agreement, the holder of the mining right must present an audited mining implementation plan and, if he is not the owner of the respective land, enter into a legal transaction with the owner of the land with the intention of obtaining the right to enable the holder of the mining right to carry out mining activities. The concession agreement process commences with a proposal submitted to the Ministry of Infrastructure. If all the requirements are fulfilled, the concession agreement is concluded for the period determined therein. When the concession agreement enters into force, the holder of the mining right must make a concession payment and reserved sanitation payment. The mining concession payment shall be paid in annual amounts not exceeding EUR 500 for each hectare of exploitation area and 30 per cent of the average price for the produced unit of mineral source in the respective year, save as in case higher prices have been reached in the auction procedure. The amount of reserved payment for sanitation is determined by the mining project.

7.11.6 Forthcoming developments

In recent years, Slovenia has established a good legal framework and a healthy market conditions in the energy sector, which enabled it seamless transition to a completely liberalised energy market. Despite successful development in the past, Slovenia is continuing to keep up with challenges and changes of the always evolving energy sector.

On one side, Slovenia is working on two major legislative packages which will amend the Energy Act in the near future and ensure the implementation of the latest EU legislation. On the other side, Slovenia is further developing the required infrastructure. In parallel, market actors themselves are also actively involved in the development of the sector.

Regulatory changes

Notwithstanding that since the implementation of the Energy Act in 2014 no major issues with its implementation have been identified, two important amendments to the Energy Act are envisaged in the near future.

The first amendment is envisaged to be adopted during the present year and will provide (i) complete harmonization with Directive 2010/31/EU, Directive 2012/27/EU, Regulation (EU) 2017/1938 and Regulation (EU) 2017/1369 by way of extending the obligation to install the energy certificate on a visible spot also to the owners and lessees of buildings in which the public usually stays and by providing a definition of "effective remote heating and cooling"; (ii) implementation of the Slovenian Constitutional Court's decision pertaining to payment of damages for the use of land plots for construction of energy infrastructure before the expropriation decision; (iii) harmonization with Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01) regarding the lower threshold for the support to alternative energy sources production facilities in the form of guaranteed purchase of electricity (from 1 MW to 500 kW) and (iv) certain new and innovative solutions, such as (a) introduction of the new market actor in the sector called "aggregator" who uses specific knowledge and software to act in the market as an intermediary, combining multiple customer loads or generated electricity for sale, for purchase or auction in any organised energy market and (b) prohibition of certain unfair and misleading (business) practices as carried out by intermediaries (e.g. door-to-door sales people and commercial agents when acquiring new clients). The amendment shall, among other smaller changes, also enable the state to statistically meet the goals for production of energy from renewable sources by investing in renewable sources in other countries.

The second amendment, which will mainly transpose the "Clean energy" package (i.e. eight EU directives) into Slovenian legislation is envisaged to be adopted after 2020.

Additionally, also adoption of the new Energy Concept of Slovenia, which will provide strategic guidelines for the future development of the energy sector in Slovenia, took place in 2019. The proposal of the new Energy Concept contains the projections of secure, sustainable and competitive energy supply for the future and ambitious objectives from various fields of energy policy until years 2030 and 2050. The key challenges addressed in the proposal are gradual increase of efficient use of energy, increase in the production of energy from renewable sources and thus reduction of conventional fossil fuel resources, namely, the priority targets are the reduction of greenhouse gases emissions by at least 40 per cent by 2035 and 80 per cent by 2055, in comparison with 1990 levels. In addition to the Energy Concept of Slovenia which shall determine the energy program on the national level, the Energy Act envisages also adoption of local energy concepts, which will have to be in line with the Energy Concept of Slovenia and shall determine the concept of development of the local community (or several communities) on the field of energy use and energy supply.

Infrastructure investments

According to applicable legislation, ELES d.o.o. is obligated to prepare a development plan for the electricity transmission network for the next ten-year period every two years. The plan presents the anticipated state of the electric power system and the necessary expansions and interventions for the transmission network. ELES d.o.o. coordinates two types of projects: transmission network projects and projects of common interest.

Similarly, Plinovodi d.o.o. prepared the Ten-Year Gas Transmission Network Development Plan for the 2019 – 2028 Period laying down the most important gas infrastructure projects. Depending on its purpose, the planned infrastructure is broken down into: projects for increasing operational security and expansion of the transmission system, projects for connecting new natural gas consumers or changing the operational characteristics of gas infrastructure, and projects for developing interconnection points. The transmission system operator estimates to have a total of 24 projects in preparation and planning in the 2019 – 2021 period and to carry out (construct or begin construction on) 17 of those projects, while 7 will remain in planning with envisaged investments in studies, location and investment documentation in the next three years.

Other improvements

In parallel to the efforts of the state to further improve the operation of the energy sector, enhance its efficiency and establish excellent infrastructural and legal framework, the industry itself is also well connected through various initiatives and tries to be involved in the future decision making. Just recently, in mid 2019, Chamber of Commerce and Industry of Slovenia established Strategic Counsel for Energy Transition, composed of energy producers, distributors, energy intensive users, transport industry representatives, research institutes etc. The aim of the counsel is to provide the legislator with insights end experience from within the sector in order to balance legislator's interests, goals and expectations. Such initiatives further help Slovenia to stay on the right path towards highest levels of efficiency, reliability and connectivity.

7.11.7 Impact of the coronavirus pandemic on the energy and infrastructure [58]

A. Covid-19 Response Investment and Support Initiative – General

In response to the Covid-19 pandemic, several initiatives to support the economy have been implemented in Slovenia. The government has passed several intervention laws which include measures for undertakings as well as individuals. Slovenian Export and Development Bank ("SID Banka") and Slovene Enterprise Fund ("SEF") have introduced additional support schemes to ensure the liquidity of the economy. Special support for Slovenian tourism is available through the Slovenian Tourist Organization.

Among others, the measures implemented by the intervention laws include measures for the protection of jobs, tax measures, measures related to bank loans moratoriums, payments under public sector contracts, public procurement procedures, insolvency procedures, enforcement procedures, KYC processes, submissions of annual reports, and administrative and judicial proceedings.

Both, SID Banka and SEF have already implemented several measures to secure sufficient liquidity of the economy and have announced that further measures will be adopted in the future. Particularly in respect of the energy sector, the Slovenian Government issued an Ordinance on temporary non-payment of contributions and network charges to provide support for electricity generated from renewable energy sources and from high-efficiency cogeneration for small business users of electricity for the period from 1 March 2020 to 31 May 2020. The adopted measure is expected to reduce the electricity bills for small business users by an average of 20% during this period.

In general, most of the measures apply to all private economic sectors; however, with certain exceptions. Financial institutions and insurance companies are exempted from taking advantage of certain measures under the intervention laws. Further, some measures of SID Banka and SEF are intended only for companies of a certain size, i.e. micro, SME or large companies. Finally, certain support available from SID Banka and the Slovenian Tourist Organization is intended only for the Slovenian tourism sector. One of the main objectives of the intervention laws was to provide support to all companies and individuals who have been negatively affected by the Covid-19 pandemic. Therefore, the measures cover all types of companies, including self-employed and other forms of entities through which a business activity may be performed.

[58] The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

In order to achieve their objective, the measures cover a wide spectrum of support. Measures implemented by the intervention laws which are intended to protect jobs include salary reimbursements, release from payment of social security contributions, additional payments to exposed workers, financing of sick leave compensation, income compensation for self-employed, solidarity payments, and seasonal work in agriculture.

Intervention laws also include moratoriums on bank loan payments, shorter payment deadlines under public sector contracts, and an increase of thresholds for organisation of public procurement procedures.

SID Banka will offer financial products to SMEs and large companies in the total amount of EUR 800 million. The funds are intended to address liquidity problems, problems due to fall in demand, production fall-out, supply chain difficulties, and investment difficulties. Measures that are already available include direct and indirect financing, guarantees, and credit insurance. Other measures such as export insurance and other forms of guarantees and financing have been announced for the future.

SEF is planning to introduce a package of measures intended for micro-companies and SMEs in the total amount of EUR 115 million. Currently, SEF is offering different types of guarantees for micro-companies and SMEs in the total amount of approximately EUR 80 million. The fund is expected to introduce additional support measures which will include loans and amendments of repayment conditions under the existing loans granted by the fund.

In general, all support measures are available to any undertaking, with certain exceptions for financial institutions and insurance companies which are not able to take advantage of salary reimbursements and release from payment of social security contributions under intervention laws. In any case, the majority of measures require that the requesting undertaking has duly settled their tax and social contribution obligations.

Moreover, salary reimbursements will be available only to the employers (i) whose revenues in the first half of 2020 will decrease by more than 20% compared to the first half of 2019, and (ii) whose revenues in the second half of 2020 will not increase by more than 50% compared to the second half of 2019.

Another objective of the support measures is that they are also readily and easily available. Therefore, many support measures under the intervention laws will be accessible only by the requesting undertaking issuing a statement on eligibility and applying for the support. The statement will have to state that the undertaking is requesting support due to negative consequences of the coronavirus and that it fulfils potential additional requirements for a certain type of support. The truthfulness of the statements and eligibility for the support will in many cases be reviewed in retrospect after the termination of the epidemic and the undertakings which would receive unjustified support will have to return the funds with interest.

Regardless of the theoretically easy and quick access described above, most of the measures have barely been implemented. Therefore, it is difficult to estimate how easily accessible the support measures will be in practice. Also, the state has not yet made any actual payments under the intervention laws, therefore any possible difficulties could so far not have been detected.

Most of the measures introduced under the intervention laws shall apply until 31 May 2020 or for additional 30 days, if the epidemic announcement is not revoked by 15 May 2020. However, some measures shall apply longer, e.g., application for a moratorium on loan payments may be filed within six months after the epidemic announcement is revoked and salary reimbursements may be requested until 30 September 2020.

Intervention laws also foresee tax measures which extend the deadlines for filing certain tax returns from 31 March 2020 to 31 May 2020. Companies that will not be able to generate income because of the Covid-19 outbreak will also have the possibility to apply for deferred payment of taxes or tax payments in instalments for up to 24 months. However, the tax payment deferral regime will not apply to payments of social security contributions. Another tax measure is the exemption from payment of advance corporate income tax under which advance payments otherwise due until the end of May 2020 are exempted.

So far, the implemented support measures do not cover any existing insurance coverage. However, the government has already announced that additional measures will be introduced, therefore those could also include actions in respect of existing insurance coverage.Selih & partnerji's web info hub dedicated to providing updates on the Covid-19 related measures applicable in Slovenia is available through the following link: https://selih.si/covid-19-info-hub/.

B. Impact on the Energy and Infrastructure Sectors

So far, the Covid-19 pandemic has not severely affected the Slovenian energy sector. Some suppliers have recorded a climb in domestic demand for electricity after the declaration of epidemic in Slovenia, which is likely due to many people working from home. However, the supply of electricity has never been endangered.

Consequently, the support measures adopted by the Slovenian government did not include many specific measures related to the energy sector. In fact, the only specific measure which has been introduced is the abovementioned Ordinance on temporary non-payment of contributions and network charges to provide support for electricity generated from renewable energy sources and from high-efficiency cogeneration for small business users of electricity for the period from 1 March 2020 to 31 May 2020.

Also, the Slovenian infrastructure sector has until now not been severely affected by the Covid-19 pandemic.

Therefore, support measures adopted by the Slovenian government did not include specific measures that would be related to the infrastructure sector specifically. One measure which could be considered as partially related to infrastructure is the loosening of thresholds for organisation of public tenders in the general field. In respect of public tenders for public work contracts, the threshold for a public procurement procedure in the general field has been doubled from EUR 40,000 to EUR 80,000.

Another measure which is partially related to energy and infrastructure sectors is the extension of certain reporting deadlines as set by the Environmental Protection Act, the Water Act, and their implementing regulations. Deadlines shall run out on the 60th day after the Covid-19 epidemic will have been revoked.

7.12 TURKEY

7.12.1 Introduction to the energy market

Due to its remarkable economic growth over the past decade, Turkey's demand for energy has considerably increased. In order to meet this growing demand, Turkey's energy policy for the next ten years includes the following targets:

- increasing total installed power to 120,000 MW;
- increasing the share of renewable energy sources to 30 percent;
- establishing an energy stock exchange with a diversified product range;
- commissioning at least two nuclear power plants;
- minimizing its petroleum and gas import costs;
- maximizing the use of hydropower;
- increasing wind-power installed capacity to 20,000 MW;
- installing power plants with 1,000 MW of geothermal and 5,000 MW of solar energy;
- extending the length of electricity transmission lines to 60,717 km;
- reaching a power distribution unit capacity of 158,460 MVA;

- raising the natural gas storage capacity to 11 billion m3; and
- increasing installed coal-fired capacity to 30,000 MW.

These targets demonstrate that energy demand levels will continue to expand, as will the development of Turkey's energy market. Although in the early 2000s Turkey took remarkable steps in liberalizing its energy market[59], these steps were not sufficient to reduce Turkey's foreign dependency. Due to insufficient domestic energy generation, Turkey's primary objective is to strengthen the security of supply. Turkey is determined to diversify its energy supply routes and sources, by including nuclear energy in its generation bundle and increasing the share of renewable energy. Considering Turkey's targets for the next ten years and the substantial increase in energy demand,[60] it is clear that significant investment (more than double the total amount invested in the last decade) will be required in order to meet expected national demand levels by 2023. In line with these prospects, several significant developments affecting the Turkish energy market and its players occurred in 2017 and 2018 as outlined in the following sections.

7.12.2 Electricity

Market overview

The Turkish electricity market is one of the fastest growing electricity markets in the world, growing annually by an average of about nine percent. In addition to private companies, there are three state-owned companies[61] active in the local electricity market:

(i) Elektrik Üretim Anonim Şirketi ("EÜAŞ"), the state generation entity;

(ii) Türkiye Elektrik İletim Anonim Şirketi ("TEİAŞ"), the state transmission entity; and

(iii) Türkiye Elektrik Dağıtım Anonim Şirketi ("TEDAŞ"), the state distribution entity.

While the state generation entity, EÜAŞ, still plays an important role in this market, the role of private companies is rapidly increasing through both privatization and establishment of new facilities.

TEİAŞ conducts all of Turkey's transmission activities, effectively operating a monopoly in the local electricity transmission market. Aside from the transmission activities exclusively conducted by TEİAŞ, other market activities are fully accessible to private companies. The distribution network is divided into 21 regions, each with its own distribution company. All of these companies have been privatized since 2013. TEDAŞ no longer operates any distribution companies, but it continues to own the distribution assets. Meanwhile, EÜAŞ still has an important role in the electricity generation market, although the power plants operated by EÜAŞ are being privatized.

The new Electricity Market Law (the "**EML**") stipulated the creation of an electricity exchange market, which would be administered through a newly incorporated company, Enerji Piyasaları İşletme Anonim Şirketi ("**EPİAŞ**"). EPİAŞ was incorporated in March 2015 and obtained a market operation license on 1 September 2015. Following incorporation, TEİAŞ and the Borsa İstanbul (the "**BI**") each hold 30 percent of the corporation's total shares, with the remaining 40 percent held by various private energy companies.

Under this shareholding structure, TEİAŞ and the BI hold Class A and Class B shares, whereas private energy companies hold Class C shares. Upon its incorporation, EPİAŞ started conducting the market operation activities of the organized wholesale electricity markets (including day-ahead and real-time market activities) other than those operated by the İstanbul Stock Exchange and TEİAŞ. TEİAŞ continues to conduct balancing activities.

[59] Turkey had started a significant liberalisation process in the energy sector in 2001, with the electricity sector taking a leading role. With the liberalisation process, the Turkish energy sector became more competitive, attracting more investors in all fields of energy. However, the targeted extent of liberalisation has not been achieved in full. In any case, Turkey's long-term target is to stop being an energy importer and start exporting energy.

[60] Turkey's energy demand is estimated to grow by approximately seven per cent each year until 2023.

[61] Prior to 9 July 2018, there was a fourth state-owned company active in the electricity market, namely Türkiye Elektrik Ticaret ve Taahhüt A.Ş. ("TETAŞ"), which was a state power trading entity. On 9 July 2018, TETAŞ merged with EÜAŞ.

Regulatory overview

The Ministry of Energy and Natural Resources (the "**MENR**") is ultimately responsible for preparing and implementing energy policies, plans, and programs in coordination with its affiliated institutions. Under the MENR's support, the Energy Market Regulatory Authority ("**EMRA**") is responsible for regulating and supervising electricity market operations in a competitive environment.

EMRA's powers and duties can be summarized as issuing licenses; setting, amending, enforcing and supervising regulations on performance standards; setting out pricing principles; and maintaining the development and performance of infrastructure for implementation of new power trading and sales methods. The EMRA exercises its powers through the Energy Market Regulatory Board (the "**EMRA Board**").

The primary pieces of legislation regulating Turkey's electricity market are the EML and the Electricity Market License Regulation[63] (the "Electricity Market License Regulation").

Regulated electricity market activities

The following electricity market activities are regulated by the EML and the Electricity Market License Regulation:

(i) generation (coal, hydro, geothermal, wind, solar, hydraulic, biomass, biogas, wave, current and tidal energy sources);
(ii) transmission;
(iii) distribution;
(iv) wholesale;
(v) retail;
(vi) trade;
(vii) energy exchange;
(viii) import; and
(ix) export.

In order to conduct electricity market activities, companies must obtain separate licenses for each activity. In order to conduct a single activity in multiple facilities located in different regions, companies must also obtain a separate license for each facility.
This is the general principle, but supply license holders can conduct electricity trading activities (wholesale, export, import, and retail sales); and the individuals or legal entities that:

(i) generate electricity for their own needs; and
(ii) have facilities or equipment that are not operating parallel to the transmission and distribution network,

are not required to obtain any license, as long as they remain disconnected from the transmission and distribution networks, and do not conduct wholesale or retail activities.

In May 2019, EMRA introduced the new Regulation on Generating Electricity without a License[64] (the "Unlicensed Generation Regulation" or "**Regulation**"). Under the EML, generation facilities with an installed capacity of up to 1 MW of renewable energy resources are exempt from the licensing requirement. Moreover, if a company generates more electricity than it consumes, the surplus may be sold in the same distribution region in which it is produced, within the scope of the RER Support Mechanism; or may also be consumed in other facilities owned by the same party in the same distribution region for a period of ten years.[65] A maximum capacity of 1 MW per transformer center can be allocated to individuals or legal entities generating solar or wind energy (excluding rooftop installations), regardless of the number of consumption facilities owned by that individual or legal entity. When calculating the 1 MW limit, both the individual or legal entity and/or entities in which such persons have direct or indirect shares are considered the same person. Finally, no capacity fee is charged to the renewable energy facilities whose capacity is below 5 MW.

[62] Published in the Official Gazette dated 3 March 2001 and numbered 24335.
[63] Published in the Official Gazette dated 2 November 2013 and numbered 28809.
[64] Published in the Official Gazette dated 12 May 2019 and numbered 30772.
[65] See Section 3 for further information.

Significant sector issues

The Electricity Market License Regulation sets forth certain share transfer restrictions. Under Article 6 of the EML and Article 19 of the Electricity Market License Regulation, direct or indirect changes in shareholding structure and/or share transfers (aside from certain exceptions set forth under the Electricity Market License Regulation) are forbidden within the preliminary license period. EMRA will cancel a preliminary license if such a transaction occurs. However, Article 57 of the Electricity Market License Regulation provides exceptions to this prohibition with respect to the preliminary license period.

Accordingly, in addition to the situations relating to inheritance and bankruptcy, this prohibition does not apply to:

(i) changes in the shareholding structure of publicly listed legal entities, with regard to their publicly listed shares;
(ii) changes in the shareholding structure of legal entities with publicly listed shareholders, with regard to the publicly listed shares of these shareholders;
(iii) companies granted a preliminary license for facilities established in line with international agreements;
(iv) indirect changes in the shareholding structures of companies holding preliminary licenses resulting from changes in their foreign shareholders' shareholding structures;
(v) direct or indirect changes in the shareholding structure of an entity holding a preliminary license, caused by a public offering of this entity's shares or the shares of its direct or indirect shareholders;
(vi) direct or indirect changes in the shareholding structure of a legal entity holding a preliminary license, caused by the exercise of pre-emption rights by the entity's shareholders;
(vii) changes resulting in direct partnership of the indirect shareholders of a legal entity holding a preliminary license, which is stated in the preliminary license of such entity, without any changes in their shareholding percentages in this legal entity;
(viii) direct or indirect changes in the shareholding structure of a state-owned entity, resulting from this entity's privatization;
(ix) direct or indirect changes in the shareholding structure of an entity holding a preliminary license, among the existing shareholders, which do not result in a change of the company's control;
(x) direct or indirect changes in the shareholding structure of an entity holding a preliminary license (in which majority of shares are directly or indirectly held by state institutions and organizations), caused by a capital increase or a change in shareholders, provided that there is no new shareholder, other than state institutions and organizations;
(xi) direct or indirect changes in the shareholding structure of an entity holding a preliminary license, caused by this entity's or its direct or indirect shareholders' acquisition of their own shares, within the scope of the Turkish Commercial Code[66];
(xii) direct or indirect changes in the shareholding structure of an entity holding a preliminary license, caused by share transfers among individuals who are direct or indirect shareholders of this entity and who are spouses or first-degree relatives; and
(xiii) direct or indirect changes in the shareholding structure of an entity holding a preliminary license, the control of which is seized by the Savings Deposit Insurance Fund of Turkey.

After obtaining a license under the Electricity Market License Regulation, only the following share transfers are subject to EMRA's prior approval:

(i) direct or indirect acquisition of 10 percent or more (five percent or more in publicly-held companies) of the shares in a license-holding company;
(ii) any transaction resulting in the change of control of a license-holding company;
(iii) any transaction resulting in the change of ownership or usage rights in a licensed facility;
(iv) share pledge; or

(v) merger, in accordance with Article 59 of the Electricity Market License Regulation.

Trading including import and export

Electricity trading is regulated by the Regulation on Electricity Market Balancing and Settlement (the "**Balancing and Settlement Regulation**"). The Market Financial Reconciliation Center (the "**MFRC**") operates the day-ahead market, as well as the balancing market.

The EML and the Electricity Market Import and Export Regulation[67] (the "**Import/ Export Regulation"**) set forth the principles and procedures for electricity import and/ or export, and the principles with regards to allocation and use of interconnection capacity for cross-border trade in the electricity market. Under the Export/Import Regulation, subject to the EMRA's approval, the following entities can import or export electricity from or to countries that meet the enumerated international interconnection conditions:

(i) EÜAŞ and private companies holding supply licenses may engage in electricity import and/or export and
(ii) generation companies may engage in electricity import,

provided that the relevant provisions permitting such activities are included in their licenses.

Transmission, distribution and grid access

TEİAŞ conducts all of Turkey's transmission activities. The EML does not envisage TEİAŞ's privatization. The distribution network, however, is divided into 21 regions, with a different distribution company in each, all of which have been privatized. TEDAŞ no longer operates any distribution companies but continues to own the distribution assets. TEİAŞ conducts all transmission activities in Turkey and the 21 distribution companies conduct the distribution activities in their respective regions. TEİAŞ and the distribution companies are required to meet the demands of individuals and companies for connection to the transmission and distribution systems. The Regulation on the Electricity Market Connection to and Use of the System[68] (the "**System Connection and Use Regulation**") sets forth certain circumstances for rejection of requests for connection to the transmission system operated by TEİAŞ and the distribution system operated by the respective distribution company.

7.12.3 Renewable energy

Market overview

In recent years, investments in electricity generation from renewable energy sources have significantly increased. One of Turkey's targets is to increase the share of electricity generated from renewable sources to 30 percent by 2023.

Regulatory overview

The key legislative instruments regarding renewable energy are as follows:
(i) the Electricity Market Law and the Electricity Market License Regulation;
(ii) the Law on the Utilization of Renewable Energy Sources for the Purpose of Generating Electrical Energy[69] (the "**Renewable Energy Law"** or "**RER Law**");
(iii) the Geothermal Resources and Natural Mineral Waters Law;[70] and
(iv) the Energy Efficiency Law.[71]

In line with Turkey's substantial demand potential and its renewable energy targets, Turkey has introduced the following secondary legislation since 2013:

[66] Published in the Official Gazette dated 14 February 2011 and numbered 27846.
[67] Published in the Official Gazette dated 17 May 2014 and numbered 29003.
[68] Published in the Official Gazette dated 28 January 2014 and numbered 28896.
[69] Published in the Official Gazette dated 18 May 2005 and numbered 25819.
[70] Published in the Official Gazette dated 13 June 2007 and numbered 26551.
[71] Published in the Official Gazette dated 2 May 2007 and numbered 26510.

(i) the Regulation on Generating Electricity without a License;
(ii) the Regulation on Documentation and Support of Renewable Energy; [72]
(iii) the Regulation on Technical Evaluation of Solar Energy-Based License Applications; [73]
(iv) the Regulation on Technical Evaluation of Wind Energy-Based License Applications; [74]
(v) Communiqué on Wind and Solar Measurements for Preliminary License Applications; [75]
(vi) the Contest Regulation on Pre-License Applications Regarding Generation Facilities Based on Solar and Wind Energy; [76]
(vii) the Regulation on Renewable Energy Resources For Electricity Generation; [77]
(viii) the Regulation on Certification and Supporting of Renewable Energy Resources (the "**RERSM Regulation**"); [78]
(ix) the Regulation on Procedures and Principles Regarding Signing Water Utilisation Agreements to Conduct Generation Activity in the Electricity Market; [79] and
(x) the Regulation on Renewable Energy Resource Areas[80].

Governmental support for renewable energy investments

Renewable energy support mechanism

The Renewable Energy Law established a renewable energy support mechanism (the "**RER Support Mechanism**"). The RER Support Mechanism was formed in order to support renewable energy investments. The support mechanism includes price, terms, procedures, and principles regarding the payments from which individuals generating renewable energy within the scope of the RER Law can benefit. Article 6 of the RER Law provides the prices applicable for 10 years for those generation licenses subject to the RER Support Mechanism and commissioned until 31 December 2020.[81] Renewable energy facilities must obtain an RER certificate in order to benefit from the RER Support Mechanism. Under the Renewable Energy Law, the EMRA issues RER certificates to generation license-holders, in order to identify and monitor the type of renewable energy resources traded in the domestic and international electricity markets. RER certificates are granted for one year.

7.12.4 The oil market

Due to insufficient petroleum sources, Turkey is dependent on importation. It imports petroleum mainly from Iran, Russia, Iraq, Saudi Arabia, and Kazakhstan. While the MENR is generally responsible for the petroleum sector, the EMRA regulates the downstream petroleum market. The Petroleum Market Law[82] (the "**PML**") and the Law Liquified Petroleum Gas Market Law[83] govern downstream petroleum market activities in Turkey, along with the Petroleum Market License Regulation.[84] The petroleum markets were liberalized following the introduction of the PML in 2003 and the Liquified Petroleum Gas Market Law in 2005. In addition to private companies, the Turkish Petroleum Corporation ("**TPAO**"), a state-owned oil and natural gas company, is active in the downstream petroleum market.

7.12.5 Natural gas

Market overview

Natural gas consumption in Turkey is also increasing in line with electricity consumption. According to the MENR, natural gas demand is expected to increase at a rate of 2.9 percent per year until 2020. Due to insufficient natural gas sources, Turkey is dependent on gas

72 Published in the Official Gazette dated 1 October 2013 and numbered 28782.
73 Published in the Official Gazette dated 1 June 2013 and numbered 28664.
74 Published in the Official Gazette dated 1 June 2013 and numbered 28664.
75 Published in the Official Gazette dated 17 June 2014 and numbered 29033.
76 Published in the Official Gazette dated 6 December 2013 and numbered 28843.
77 Published in the Official Gazette dated 27 November 2013 and numbered 28834.
78 Published in the Official Gazette dated 1 October 2003 and numbered 28782.
79 Published in the Official Gazette dated 21 February 2015 and numbered 29274.
80 Published in the Official Gazette dated 9 October 2016 and numbered 29852.
81 Although the initial date set in the RER Law was 31 December 2015, a Council of Ministers' Decree dated 18 November 2013 extended the incentive term until 31 December 2020.
82 Published in the Official Gazette dated 4 December 2003 and numbered 25322.
83 Published in the Official Gazette dated 13 March 2005 and numbered 25754.
84 Published in the Official Gazette dated 17 June 2004 and numbered 25495.

imports from Russia, Azerbaijan, and Iran, in addition to LNG imports from Nigeria and Algeria under long-term agreements and spot LNG from several countries under agreements of less than one year.

Although the downstream natural gas market is open to private participation, state-owned Petroleum Pipeline Corporation ("**BOTAŞ**") still holds a significant position in this sector. BOTAŞ was established in 1974 as a subsidiary of TPAO to transport Iraqi crude oil to the Ceyhan Marine Terminal (an upstream activity). However, BOTAŞ eventually began conducting downstream natural gas activities as well, such as natural gas importation and trade and has become a key player in the downstream natural gas market. Finally, most of the state-owned distribution companies active in the downstream natural gas market have been privatized. The latest privatization occurred in 2013, when Ankara's natural gas distribution company, Başkent Doğalgaz Dağıtım A.Ş., was privatized after two previous failed attempts in 2008 and 2010. The only remaining significant state-owned distribution company is the İstanbul Gaz Dağıtım A.Ş. (İGDAŞ), which is expected to be privatized in the near future.

Regulatory overview

The EMRA is the authority responsible for regulating and supervising the downstream natural gas market. The NGML governs downstream natural gas activities, which are regulated in more detail by the Natural Gas Market License Regulation. [85] An amendment law proposing substantive changes to the NGML was prepared in 2012 and submitted to the Turkish Parliament on 4 August 2014 ("**Draft Amendment Law**"). However, as it was not discussed and passed by the Turkish Parliament by the end of 2014, the Draft Amendment Law became void.

Significant sector issues

The NGML imposes market share restrictions on companies other than natural gas producers, as well as on natural gas importers. A recent amendment in the NGML introduced another restriction: distributor license holders can have licenses in only two cities in Turkey.

Transmission, distribution, and access to the system

Distribution or transmission licensees cannot discriminate among third parties of equal status for access to storage, transmission and distribution networks. Licensees can only decline third-party access requests based on certain specific grounds. These specific grounds are:

(i) insufficient capacity;

(ii) lack of capacity to fulfill existing obligations; and

(iii) orders to pay significant financial compensations due to existing contractual obligations.

Third party access to the transmission network is regulated under the BOTAŞ Transmission Network Operation Principles[846] (the Network Code) and the Natural Gas Market Transmission Network Operation Regulation.[87] Third party access to distribution networks is regulated under the Natural Gas Market Distribution and Customer Relations Regulation. [88] Distribution companies must connect all consumers within their region.[89] A connection agreement must be concluded, and the technical connection and service lines must be established.

LNG and natural gas storage and third-party access

The NGML and the Natural Gas Market License Regulation required import license holder applicants to:

85 Published in the Official Gazette dated 7 September 2002 and numbered 24869.
86 Published in the Official Gazette dated 22 August 2004 and numbered 25561.
87 Published in the Official Gazette dated 26 October 2002 and numbered 24918.
88 Published in the Official Gazette dated 3 November 2002 and numbered 24925.
89 Distribution companies can sell their entire distribution networks prior to expiration of their distribution license by obtaining EMRA Board approval.

(i) conclude lease contracts with storage license holders to ensure storage of 10% of their annual gas import or
(ii) to obtain a commitment from storage license holders confirming that they will have such storage capacity within five years. However, the current total capacity of the three storage facilities in Turkey is below 10% of the nation's annual gas import amount. The NGML was amended in June 2016 and EMRA was granted the authority to determine the percentage of the annual gas import amount based on which a commitment will be obtained. On the grounds of this authority, EMRA recently set the applicable percentage as 1% for natural gas import license holders (including spot LNG import license holders) and natural gas wholesale license holders).

7.12.6 Upstream

Market overview

Thanks to its geopolitical position, Turkey is a critical country for petroleum and natural gas trade between the East and the West. Being the bridge between energy-rich eastern countries and import-dependent western countries, Turkey is a natural transit point for the maritime and pipeline transportation of crude oil and natural gas. TPAO is the most active state-owned company in the upstream market. [90]

Regulatory overview

While the new Turkish Petroleum Law[91] (the "**TPL**") governs upstream crude oil and natural gas activities, [92] the Law on Transit Passage through Petroleum Pipelines[93] (the "**Transit Law**") governs the transit passage of oil and gas. Turkey enacted the TPL in 2013 and abolished the former Petroleum Law [94] (the "PL") after nearly 60 years. In early 2014, the Turkish Petroleum Law Implementation[95] Regulation was introduced. The General Directorate of Petroleum Affairs (the "**GDPA**") and the Transit Petroleum Pipelines Department of the MENR are the competent regulatory bodies responsible for the oil and gas upstream market and transit activities respectively. Unlike in the downstream market, the EMRA does not play a role in this market.

Regulated upstream market activities

The TPL defines a "petroleum right" as any right arising from one of the following permits or licenses:
(i) investigation permit;
(ii) exploration license; or
(iii) production lease.

Regarding the Turkish Petroleum Law, there are no recent material changes that have to be mentioned.

7.12.7 Nuclear

In Turkey, the Law on Construction and Operation of Nuclear Power Plants and the Sale of Energy Generated from those Plants ("**Law No. 5710**") and the Regulation on the Principles and Procedures for Competition and Contracts[96] within the Framework of Law No. 5710 are the main pieces of legislation. In particular, they govern the principles and procedures of construction and operation of nuclear power plants and the sale of energy generated from those plants, together with the Decree-Law on the Organization and Nuclear Regulatory Authority[97]. On 2 July 2018, the Council of Ministers adopted the above Decree-Law, under which the Nuclear Regulatory Authority ("NRA") was established and it was assigned as the regulatory control institution for nuclear activities. In addition, the President adopted a resolution, under which the Turkish Atomic Energy Authority

90 Upon the enactment of the Turkish Petroleum Law, the Minister of Energy and Natural Resources reiterated the government's intention to privatize TPAO through a public offering of its shares.
91 Published in the Official Gazette dated 11 June 2013 and numbered 28647.
92 Under the TPL, the definition of "petroleum" includes both crude oil and natural gas.
93 Published in the Official Gazette dated 29 June 2000 and numbered 24094.
94 Published in the Official Gazette dated 16 March 1954 and numbered 8659.
95 Published in the Official Gazette dated 22 January 2014 and numbered 28890.
96 Published in the Official Gazette dated 19 March 2008 and numbered 26821.
97 Published in the repeated Official Gazette dated 9 July 2018 and numbered 30473.

(the "TAEA") (which was the former regulatory authority on nuclear energy matters) was re-established and it was assigned responsibilities only for the promotion of the development of the nuclear industry and radioactive waste management. This resolution was published in the Official Gazette dated 15 July 2018 and entered into force on the same date. By reference to Law No. 5710, the TAEA (before its re-establishment) set forth the criteria that must be fulfilled by companies wishing to construct and operate nuclear power plants in Turkey. These criteria mainly make reference to the International Atomic Energy Agency Safety Standards for nuclear safety and to the nuclear power plant exporter's nuclear safety legislation for licensing. In March and April 2017, the TAEA had issued three new regulations in the field of nuclear energy: the Regulation on the Construction Inspection of Nuclear Power Plants[98] provides for the procedures on the construction of nuclear power plants in accordance with nuclear security principles. The two other regulations govern the management of nuclear power plants and their personnel. These regulations are still in effect.
Alongside these principal pieces of legislation, IGAs and host-government agreements ("**HGA**") are concluded in order to establish a special legal regime for contemplated nuclear power plant projects. Currently, there are two nuclear power plant projects in Turkey, the Akkuyu Nuclear Power Plant and the Sinop Nuclear Power Plant.

Draft Nuclear Liability Law

Turkey has ratified the Convention on Third Party Liability in the Field of Nuclear Energy of 29 July 1960, as amended by the Protocol of 28 January 1964 and by the Protocol of 16 November 1982 (the "**Convention**"). In line with Article 7(b) of the Convention, the maximum liability of the nuclear installation's operator in respect of damage caused by a nuclear incident is 15 million SDR. Turkey has signed but not ratified the 2004 Additional Protocol to the Convention, which sets forth EUR 700 million as the operator's minimum liability. Turkey does not have any domestic law related to compensation for nuclear damage. However, a MENR official document dated 26 February 2016[99] stated that the Ministry has prepared a draft law on third party liability in the field of nuclear energy (the "Draft Nuclear Liability Law") and this law will be enacted within 2016. However, it was still not enacted. The Draft Nuclear Liability Law text has not been disclosed to the public. However, the same document further provides that the Draft Nuclear Liability Law was prepared in line with the 2004 Additional Protocol to the Convention, and the prescription period for nuclear damage claims will be extended to 30 years for actions regarding loss of life and personal injury, and in addition the operator of the nuclear power plant will be required to have and maintain insurance to cover its liability as in the 2004 Additional Protocol to the Convention.

7.12.8 Impact of the coronavirus pandemic on the energy and infrastructure[100]

A. Covid-19 Response Investment and Support Initiative – General

To mitigate the impacts of the Covid-19 pandemic, President Erdoğan declared the Economic Stability Shield ("ESS") on 18 March 2020. The ESS mainly introduced financial measures, which ultimately aim to allow businesses to postpone their short-term debts, e.g., tax and social security payments, loan repayments, etc. without any penalty or late payment interest and to expand their financing options. The ESS covers all sectors with a specific focus on companies operating in the most affected segments. The Ministry of Treasury and Finance ("Ministry") identified the most affected businesses as retail/shopping malls, iron & steel industry, automotive industry, logistics/transportation, entertainment, accommodation, textiles and event planning. While the measures adopted under the ESS are not sector-specific, there are certain benefits granted exclusively to SMEs

98 Published in the Official Gazette dated 31 March 2017 and numbered 30024.
99 http://www2.tbmm.gov.tr/d26/7/7-1446sgc.pdf
100 The South East Europe Energy Handbook Special Edition "Overview of the Coronavirus Support Initiative & Impact on the Energy and Infrastructure Sectors in Southeast Europe", https://seelegal.org/see-legal-joint-publications/see-special-energy-handbook

and merchants/craftsmen. For example, loan repayments of merchants and craftsmen to Halkbank (a state-owned bank) in April, May and June are postponed for three months without interest. Repayment of loans that are due in April, May and June, by SMEs benefiting from the SMEs Development and Support Administration's (KOSGEB) support system are also postponed for three months. Extended insurance coverage in favour of SMEs is also an aspect of the support system introduced under the ESS.

Under the ESS, financial support is provided to businesses in multiple ways. Loan repayment obligations of companies, cashflows of which have been deteriorated due to the Covid-19 spread, are deferred for at least three months and additional financial support will be provided to these enterprises if need be. The scope of this additional support scheme has not been clarified yet and secondary legislation is likely to be introduced on this matter. Furthermore, companies that fall in default during April, May and June on repayment of their loans due to the financial effects of Covid-19 are assured to have a "force-majeure" remark on their credit records. This remark will procure that these companies' credit scores will not be affected adversely due to their payment defaults. In the meantime, SMEs and companies that (i) need liquidity due to negative impacts of the recent developments and (ii) have security deficit will be prioritised in obtaining loans. Stock financing support will also be available to export companies. An additional credit limit will be allocated by public banks and some private banks for certain payments, e.g., commercial checks, salaries, loans. The criteria to grant such additional credit limit will vary for each bank. Finally, the Credit Guarantee Fund limit is also increased from TRY 25,000,000,000 to TRY 50,000,000,000. The preliminary criteria for companies to benefit from the said support mechanisms is that their businesses must have been affected negatively due to the Covid-19 pandemic. Certain support mechanisms such as the "Business Continuance Credit Support" require fulfilment of specific eligibility benchmarks, such as not terminating any employment contracts during the pandemic period. Finally, as mentioned above, the ESS provides certain sector-specific benefits for the most-affected industries and accordingly companies must be operating in one of these sectors to enjoy these sector-specific benefits. The greater part of these support mechanisms will be enforced by governmental authorities, so they are easy to access. Enterprises will be able to benefit from the support systems by applying to the relevant governmental authorities/banks.

It is worth emphasizing that the **ESS is quite new and as of today the measures/support mechanisms that it has introduced have not been tested.** It is yet difficult if not impossible to predict the ease or speed of access to the benefits provided under this program. While the applicability period of each support mechanism differs, the ESS focuses on short term measures, i.e. April, May and June 2020. Tax is one of the areas covered under the ESS. For example, the deadline for VAT declarations (i.e., 26 March 2020) and the payment periods of the taxes accrued based on these declarations have been extended to 24 April 2020.

The deadline for filing BA (purchases of services and goods)/ BS (sales of services and goods) forms on the 2020/February period, which were due by 31 March 2020, have been extended to 30 April 2020. All applications/submissions to be made to tax offices must be made via the Interactive Tax Office's website or via post until 10 April 2020. In addition, the Ministry has also declared the presence of a force majeure situation for some sectors (e.g., retail/shopping malls, food and beverage sector, health services, mining, car rental, press, logistics) until 30 June 2020. For these sectors, deductions for withholding tax and VAT have been deferred until the end of October 2020. In terms of insurance, the scope of the "State-Backed Commercial Receivable Insurance" which was available to institutions with an annual turnover of TRY 25,000,000 or less has been extended to cover SMEs with an annual turnover of up to TRY 125,000,000. SMEs opting to benefit from this support will be able to have insurance coverage for their commercial receivables up to a limit of TRY 750,000.

This figure can be increased subject to further valuation under risk assessment criteria. Under Turkish law, employers who have suspended activities in their workplaces due to an extraordinary event (i.e., force majeure) may apply to the Turkish Employment Agency for temporary short-term working pay support.

With the recent legislative amendments, the eligibility criteria (e.g., required premium payment terms) for short-term working pay is now more flexible and the application process with the Turkish Employment Agency is expedited. Implementation of flexible and remote working models existing under the Labour Law is increasing gradually both in public and private sectors. President Erdoğan has also declared that payment of social security premiums by employers operating in the heavily-affected sectors for April, May and June have been deferred for six months.
Some useful links include:

- https://tobb.org.tr/Sayfalar/20200323-covid-destegi.php
- https://kpmgvergi.com/Content//FinancialBulletins/%E2%80%9CEconomicStabilityShield%E2%80%9DannouncedtoeliminateanypotentialdamageofCOVID-19breakouttoTurkisheconomy_20032020_0557555365151.pdf
- https://www.pwc.com.tr/en/hizmetlerimiz/vergi/bultenler/2020/covid-19-emergency-tax-measures-for-turkish-companies.html

B. Impact on the Energy and Infrastructure Sectors

The energy sector is among the sectors affected by the Covid-19 pandemic. The Energy Market Regulatory Authority ("EMRA") recognised the pandemic as a force majeure event and has adopted certain measures for providing further flexibility to market players, to ensure continuity of energy investments in the country. For example, time-sensitive obligations of pre-licence or licence holders ending on or after 10 March 2020 have been extended for three months. The application period for a wind power plant pre-licence has been postponed from 6-10 April to 5-9 October 2020. EMRA has also suspended the requirement to add 3% ethanol into gasoline until 13 June 2020, considering the growing need for disinfectants in public. Finally, the Turkish government has prepared a draft bill for amending certain laws (the "Draft Omnibus Bill"). The Draft Omnibus Bill is expected to allow enterprises to terminate their generation or auto-producer pre-licences, licences or licence applications by applying to EMRA. The Draft Omnibus Bill provides that certain power plant installation contracts and electricity sales agreements for establishment of local thermal power plants can be terminated. The Draft Omnibus Bill is expected to come into effect in the coming weeks.

There are no specific measures/benefits introduced for the infrastructure sector due to Covid-19 pandemic and, consequently, companies operating in this sector can benefit from the support mechanisms provided under the ESS as any other business owner. That said, recently a force majeure guideline for public tender contracts has been issued. This guideline enables undertakers to apply to the contracting public authority if it is temporarily or permanently impossible for the undertaker to execute the contracted project due to the pandemic. If, in light of evidentiary documents, the contracting public authority decides that (i) the delay did not occur due to undertaker's fault, (ii) the ongoing incident prevents the undertaker from performing its contractual obligations and (iii) the undertaker is unable to cease the effects of the ongoing incident, an extension can be granted to the undertaker for performing its contractual obligations, or the contract may be terminated at the relevant public authority's discretion. Meanwhile, the demand for pandemic hospitals has increased due to the Covid-19 pandemic. For example, construction of the İkitelli City Hospital is expedited and it is planned to be completed in May 2020. Furthermore, two new pandemic hospitals will be built in Istanbul within the next 45 days.

Finally, periods for initiating legal proceedings and those relating to ongoing legal proceedings as well as the statute of limitations have been suspended until 30 April 2020 (inclusive). This extension also applies to execution and bankruptcy proceedings.

8

Hydrocarbon Exploration and Production in SE Europe

Hydrocarbon Exploration and Production in SE Europe

Introduction

The dynamics of the global energy scene in the foreseeable future are largely based on natural gas and supported by the drive towards alternative energy sources. A significant increase in the production of gas is expected, and this will act as a key driver in the international energy market over the next five to ten years. Oil and gas trade continued to fuel market growth during 2018-2020 and most countries in SE Europe and the East Mediterranean continued their efforts to develop significant potential. It is estimated that global oil demand by 2026 will rise to 104 MMbbl/d and natural gas will continue to expand its share across major markets.

With the Covid-19 pandemic, the oil and gas industries are undergoing rapid transformation across the world. Oil and gas companies will need to expand their production to meet emerging demand in the years ahead. The innovations brought by new technologies allowed unconventional drilling to enhance production and new business models and services have evolved rapidly, reducing operating costs. Exploration of underwater gas deposits are key, and most future energy development scenarios are sea-based. Although the pandemic has hit the economy hard with the downsizing of exploration budgets, the shift to renewable energy sources and the renegotiation of deals will support global demand for hydrocarbons in the coming years. Several large producers including Exxon Mobil, ConocoPhillips, BP, Royal Dutch Shell and Total embraced market-based policies in order to limit emissions (1).

According to the IEA (2), gas will continue to act as a bridge fuel to new energy sources for decades, unless major technological advances take hold and real alternatives emerge. In that sense, exploration and production of gas fields in SEE and the East Mediterranean are expected to provide an opportunity for the companies working in the oil and gas midstream industry as more pipeline and storage infrastructure will be required. Within this complex environment a number of drilling campaigns were undertaken in 2019-20 focusing mostly on proven core basins and on few frontier unproven basins around the world. In 2021/2022 hotspots will include basins in Mexico, Brazil, the US Gulf of Mexico and the Middle East. However, mature provinces in Angola, Gabon, the UK North Sea and Egypt still have very significant potential, and newcomers Namibia and Suriname may offer some surprises (3). The Levant basins host two major gas targets in Zeus, offshore Israel and Block 9-1, offshore Lebanon.

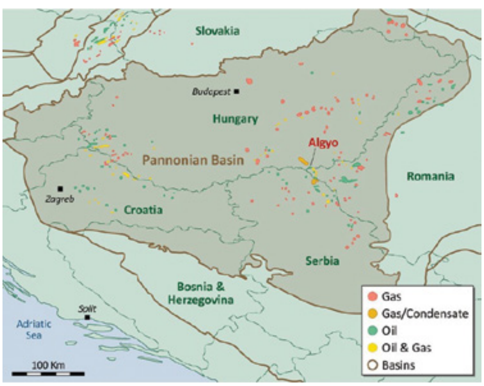
The Adriatic and the Dinarides

Over the last two years (2019/2020), SEE countries on average were more than 60% dependent on oil and gas imports for covering their energy needs. According to the Balkans and Black Sea Association (2019), Romania and Croatia decreased their crude production while Albania, Hungary and Turkey increased theirs. Refinery throughputs were up by 11%, excluding Bosnia-Herzegovina and Serbia. Gas production decreased by 3% in Croatia, Romania, Serbia, Hungary, Turkey and Ukraine. Gas demand decreased overall by 5% but rose in Croatia, Greece, Georgia and Hungary, and fell in Bulgaria, North Macedonia, Romania, Serbia, Turkey and Ukraine.

Five gas pipelines are under construction or in the design phase. Croatia, Hungary and Romania launched new tenders for onshore exploration blocks. Croatia, Boznia-Herzegovina, Montenegro and Albania, in the eastern part of the Adriatic, have over the past years, through licensing rounds, granted onshore concession and offshore areas for hydrocarbon research and exploitation, while deep water exploration activities continued outside the Adriatic and the Dinarides mostly in the EastMed and the Black Sea (4,5).

The technical exploration success rate in the eastern European Pannonian Basin over the last three years (4) (Map 8.1) ranged between 83% and 94%, while the commercial oil and gas success rate was at least 50%. The Pannonian Basin stretches over Bosnia-Herzegovina, Croatia, Slovenia, Austria, Hungary, Slovakia, Ukraine, Romania and Serbia with a multitude of jurisdictions (7). Formal licensing rounds in Bosnia-Herzegovina and Romania offered blocks in the Pannonian Basin in 2020, following Croatia's success in 2019. In addition to former state players such as MOL, INA, NAFTA and NIS, just four oil companies have operated exploration wells in the Pannonian Basin recently. ADX, Aspect, Serinus and Vermilion have all had success, mostly in finding gas deposits. They have built a portfolio of assets across Croatia, Hungary and Slovakia, taking advantage of underinvestment in the Pannonian Basin and the opportunity to apply modern technology at low cost.

Map 8.1 **Discoveries in the eastern European Pannonian Basin**

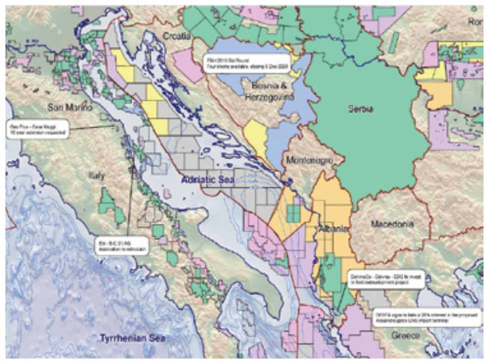


Source: Croatian Hydrocarbon Agency, 2020 (5).

Reported flow rates are in the range of 1.4–17.2 MMcfgpd with the typical individual pool size a modest 20 Bcf. Reservoir depths average 2,200m and drilling costs are relatively low. The key to success seems to be the application of modern techniques, in particular 3D seismic hunting for DHIs, across several reservoir targets in a structured basin where the risk on hydrocarbon source and migration is low. In 2006 the US Geological Survey estimated a mean Yet-To-Find of 1.1 Bboe for the basin, with an upside of 2.2 Bboe.

Croatia, Montenegro and Albania have proven petroleum systems offshore, while Croatia and Albania have production in shallow water depths (under 300m for Croatia and 50-250m for Albania) (7) (Map 8.2). Croatia had also gone ahead in 2014-2015 to award tenders for some of these regions, but the sudden drop in the price of led to withdrawals by the industry.

Map 8.2 **The Adriatic Sea**



Source: Enverus Asset Evaluator, November 2020 (7).

The Eastern Mediterranean

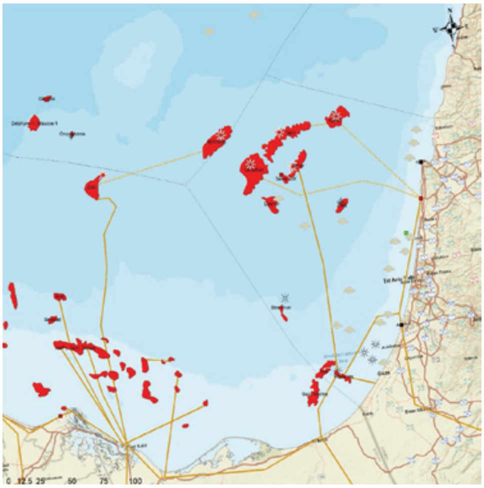
The Eastern Mediterranean has lately become a center for the exploration, production and transport of hydrocarbons. The total gas reserves discovered over the last decade in Egypt, Israel and Cyprus are estimated at 80 TCF (trillion cubic feet) with two dominating large producing fields, Zohr in Egypt (30 TCF) and Leviathan in Israel (22 TCF) (Map 8.3). While investment in exploration and production (upstream) continued, the industry remained cautious of the large investments needed to develop and transport hydrocarbons (midstream) because the total current exploitable volumes of natural gas in the Mediterranean are not yet sufficient to support long-term investments.

More discoveries are needed to support large midstream investments. After certifying the commerciality of these two fields, in the case of Zohr (Egypt), natural gas started flowing to Egypt in just two and a half years after the discovery. Similarly, the Tamar (Israel) sends gas through an undersea pipeline to Israeli land-based facilities. The recent development plans for the production and transmission of gas from the Karis and Tanin, Aphrodite, Kalypso and Glafkos reservoirs could in the coming years be linked to facilities in Egypt or Cyprus, or to major pipelines under consideration such as the East Med (8). Similarly, the exploration of maritime Gaza in coastal Palestine is on standby, while Lebanon proceeded in 2020 with its first offshore exploratory drilling. Average water depths of the explored areas vary from 1,200 to 1,500 meters in the eastern regions of the Mediterranean, are up to 2,000 meters in the western part of the Black Sea and much deeper, up to 3,000 meters in the southern Ionian and south of Crete (Map 8.4). This has significant technical and economic implications for the exploration and production of hydrocarbons in Greece and neighbouring offshore Libya and Turkey.

By the end of 2020, almost all countries in the Eastern Mediterranean and the Adriatic had, or were planning to have, FSRU facilities, while in the case of Egypt we have two fully operational liquefaction plants which produce and export LNG. Needless to say, there will soon be an overconcentration of facilities. In order to re-gasify the liquified gas it needs to arrive by vessel from nearby or remote areas outside the Mediterranean where most liquefaction plants operate. It is estimated that world investment in all types of LNG facilities over the next ten years will be close to $1 trillion.

But the decline in consumption and the recession due to the Covid-19 pandemic affected many ongoing or planned projects. It will be difficult to figure out which way the scale will tilt in two years, i.e., LNG facilities or additional offshore pipelines in the South-East Mediterranean. Furthermore, the development of SSLNG (Small Scale Liquified Natural Gas) technology may add a new parameter.

Map 8.3 **The Eastern Mediterranean exploration, production and transport of hydrocarbons in 2019**



Clouds=oil and gas shows/dry wells, small stars= sub commercial discoveries, large stars= commercial discoveries, red stars= over 2 TCF of gas, red spots= LNG, green spots= FSRU, bold brawn lines= gas pipelines, dashed brawn lines= possible pipelines (8).

A major project in the region, the East Med Pipeline, which will link the East Mediterranean to Europe would cost over EUR 7 billion, while the financing of new liquefaction LNG terminals in the Mediterranean would cost around EUR 3 billion (9). Both methods are costly in terms of global competition. Alternatively, the existing liquefaction facilities in Egypt are competitive and sufficient to realistically absorb much of the available natural gas produced in the region. Most of the new gas to be produced in Egypt over the coming years, will primarily serve the needs of its fast-expanding domestic market, leaving liquefaction capacity spare to absorb the extra gas volumes to be produced in Israel, which are mostly destined for export. In Cyprus, the structures of Glafkos, with an estimated 5-8 TCF of gas in deep rocks below 2,000 meters of water, the 4.5 TCF "Aphrodite" and the 6 TCF "Calypso", do not meet the economic criteria for managers to proceed with production and transport (Middle East Petroleum and Economic Publications, 2019, Upstream Oil and Gas, March 2019). In the case of the Aphrodite field a decision was lately taken to transport its gas directly to one of the two liquefaction plants in Egypt.

8

At this stage, and in view of the great uncertainty in the decision-making process, decisions have to be made based on a 90% success probability, - rather than a 50% probability which until recently was the norm - which greatly reduces the chances of commercial utilization in the immediate future (10).

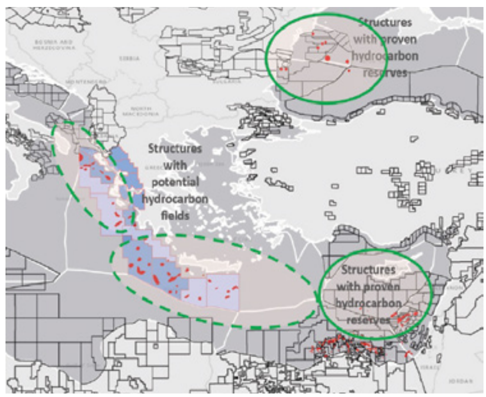
Map 8.4 **Average water depths in the eastern regions of the Mediterranean.** Dephts vary from 1,200 to 1,500 meters, are up to 2,000 meters in the Black Sea and much deeper, up to 3,600 meters in the southern Ionian and south of Crete.

Source: Morpho-bathymetric synthesis of the Mediterranean Sea, CIESM and IFREMER, 2012

Looking at the long term, besides natural gas and possibly oil deep beneath the Southeastern Mediterranean, mud volcanoes and hydrates are also present on the sea bottom, as evidenced by the release of methane or its retention in the ice of the surface layers of the sea bottom. All three types of gas presence, presently exploited with deep drilling, will be of interest to the industry for the next 30-40 years. In Greece, within the next decade renewable energy sources will most likely cover an average 40% share of power generation. Hydrocarbons, especially gas, will play a key role in the energy transition as continued imports of liquefied natural gas show. Over the next decade these imports will increase from 6 to 10 BCM per year to balance the phasing out of lignite, the reduction in oil use and the low efficiency of renewables.

As Greece is likely to be the common gas recipient from future production but still struggles to make important strides in its deep-water exploration acreage (Map 8.5), Turkey, Israel and Egypt will vie for dominance in supplying an ever-richer gas mix to European markets. Egypt is emerging as a regional gas regulator, importing and exporting gas with infrastructure and demand developing constantly. On the other hand, reversing gas through the Ashkelon-El-Arish line from Israel to Egypt could be the first step towards large-volume gas sales through new pipelines in the future. Israel, Greece and Cyprus have agreed (signing an official intergovernmental agreement on January 2, 2020) to work together in developing and ultimately building the East Med gas pipeline to run from Israel to Greece, via Cyprus, eventually landing in the south of Italy (3).

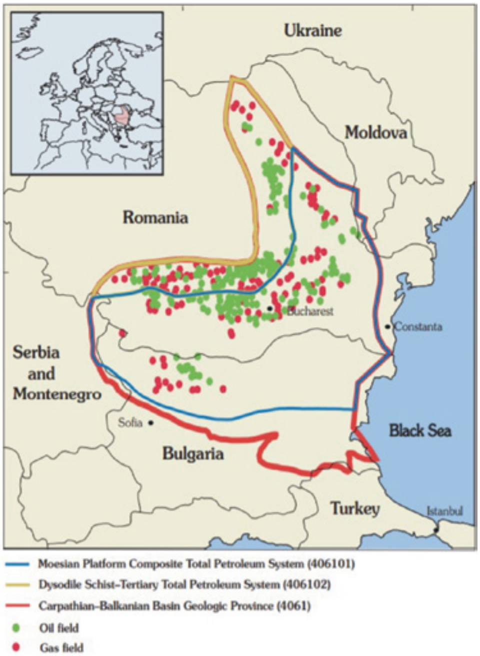
Map 8.5 **The estimated gas resources** from 30 potential leads west, southwest and south of Crete and from the Ionian Sea are between 70 and 90 TCF (12 to 15 Bboe). This may increase the potential of gas reserves in the Southeast Mediterranean and push the edge of the future gas province further west (10)



Eastern Balkans

The Carpathian–Balkanian Basin Province lies in northern Bulgaria and southern and eastern Romania (11) (Map 8.6). The western and northern parts of the province are dominated by a series of extensive nappes that form much of the Carpathian Mountains chain, whereas the eastern and southern parts are characterized by a relatively stable structural platform containing several intraplatform basins. Petroleum is produced mainly in the northern and western parts. On the basis of known petroleum volumes (amount produced to date plus remaining reserves), the Carpathian–Balkanian province has a total of 5.9 billion barrels of oil, 7.3 trillion cubic feet of gas, and 100 million barrels of natural gas liquids, for a total of 7.2 billion barrels or oil equivalent (11).

Map 8.6 **Carpathian–Balkanian Basin Province (4061)** Romania and Bulgaria, showing boundaries of the Moesian Platform Composite Total Petroleum System and the Dysodile Schist–Tertiary Total Petroleum System and locations of oil and gas fields

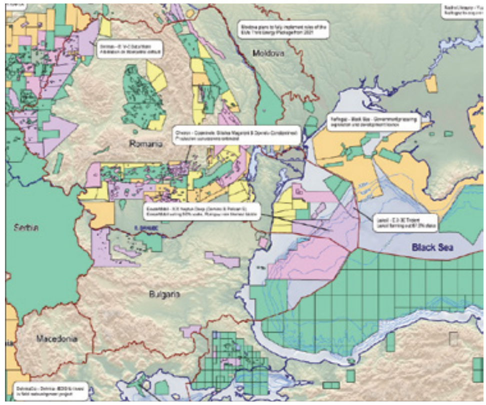


Source: USGS Bulletin 2204–F (11)

Western Black Sea

As exploration and development in the Northwest Europe region continues to recede, oil companies are pushing the search for oil and gas into regions that previously had not been considered promising but today attract offshore oil and gas exploration and development activities. The Black Sea remains one of the largest underexplored rift basins (Map 8.7) in the world and there are still controversies concerning the regional geology. Success will ultimately depend on a better understanding of several geological uncertainties such as the timing of basin formation, uplift of the margins, and of facies distribution. These are key factors for the understanding of the reservoir, the source rock presence, the quality and the timing of migration of hydrocarbons relative to trap formation. The Black Sea basin, has renewed interest, with new fields being developed and major pipelines being installed.

Map 8.7 **Eastern Balkans and Western Black Sea acreage**



Source: Enverus Asset Evaluator, November 2020 (12)

Croatia

Croatia, at the crossroads of Central Europe, the Balkans and the Mediterranean, is split geologically into two main onshore provinces, the Pannonian Basin Province and the Dinarides, and has an elongated offshore territory in the Adriatic. The onshore areas are covered by 19,850 km of 2D legacy seismic data and 1,710 sq km of 3D legacy seismic data, together with 593 wells, mainly from the Pannonian basin (13) (Map 8.8). The Pannonian Basin is well explored with 2D and 3D seismic and drilled wells. Oil production is underway in several parts of the Pannonian Basin in the fields of Beničanci, Stružec, Žutica, Šandrovac, Ivanić, Lipovljani, Jamarice, Đeletovci, Jagnjedovac and Bilogora, and gas production in Molve, Bokšić, Kalinovac, Stari Gradac and Okoli (14,15).

However, the Dinarides area has not been adequately investigated by deep exploratory drilling. Few wells have been drilled in the interior by INA, ECL and Amoco in 1990's. The remaining wells are restricted to the coastal area and the islands. Well control is satisfactory for the Upper Cretaceous, but only ten wells

8

have penetrated the Jurassic and Triassic reservoirs. The main prospects are believed to lie in the Permian to Tertiary section which is developed primarily in carbonate facies while clastics and evaporites are developed locally and they are secondary targets. Non-commercial hydrocarbons were discovered in the Dinarides (gas was discovered on the island of Brač in the Brač-1 well in 1979 and oil was encountered in 1966 in the Ravni kotari-2 well). Between 1959 and 1989, nine wells were drilled in the Dinarides (onshore), with depths ranging from 250 m (Bru-1P) to 5,600 m (Nin-1A).

The Adriatic basin is surrounded by mountain chains; the Apennines, Alps and Dinarides, and the alluvial Po plain in the north. The Croatian Adriatic offshore is covered by 26,000 km of 2D legacy seismic data, 3,800 km of 2D and 4,600 sq km of 3D recently acquired data together with 49 wells. The licensing process in Croatia is carried out by the Croatian Hydrocarbon Agency. The present regulatory framework was adopted in 2013 according to the European Union Directives and best international practices.

Licensing update in Croatia onshore and offshore

In the last two years, three tenders were released by the Croatian Hydrocarbon Agency for oil and gas (16):

- In November 2018 – A 2nd Onshore License Round O&G, with 7 onshore blocks on bid; six blocks were awarded (Map 8.9). The Croatian government had awarded six onshore exploration and production licenses for six blocks of a total of 14,000 sq km for up to 30 years. In April 2020, INA signed three onshore oil and gas exploration and production-sharing agreements, in line with a recent decision of the Croatian government to sign contracts for two onshore blocks with Croatian Crodux Derivati, one block with Vermilion and one block with Aspect.
- In January 2019 Croatia held the 3rd Onshore License Round O&G, putting four blocks up for bids in the Dinarides, covering 12,134 sq km. The company, INA, submitted a bid for block D-14 (Map 8.10).
- In 2019, Croatia released 28 offshore blocks under the "Open Door" process (Map 8.11). In 2014 a large 3D marine seismic acquisition was completed and led to the first License Round which did not attract the interest of the industry at a time when the price of oil had dropped sharply.

In March 2020 the Croatian Hydrocarbons Agency (AZ U) has released two Adriatic Sea areas, SJ-02/SJ-03 and SJ-06/SJ-07/SrJ-09, for bidding in Croatia's Second Offshore Licence Round. SJ-02/SJ-03 (2,266 sq km) lies adjacent to the E of INA's Ivana PSA in the Northern Adriatic.

Several tenders were released for the exploration of geothermal fields for energy purposes:

- July 2018 - exploration of geothermal waters for energy purposes in four fields
- June 2019 - one exploration field
- August 2019 - two exploration fields
- September 2019 - one field for exploration of geothermal waters
- October 2019 - one field for exploration of geothermal waters
- June 2020 - four blocks for exploration of geothermal waters

Oil and gas production and further potential

Currently, there are 54 production fields in Croatia, including oil, condensate and natural gas in the continental area of the country. A total amount of 92 MMt of oil, around 9 MMt of condensate and 60 Bcmg have been recovered since 1941, when the onshore hydrocarbon production in the Republic of Croatia was first recorded. Around 3,233 well have been drilled, of which 918 were exploration wells.

The largest annual recovered oil amount in Croatia was recorded in 1981 at 3,14 Bt. The largest recovered natural gas amount of 2,2 Bcmg was recorded in 1989.

The annual recovery in the continental area of the Republic of Croatia currently amounts to 500 MMt of oil and condensate and 725 MMcmg of gas (Table 1).

Table 8.1 **Crude oil is produced from 38 oil fields and gas condensate from 9 fields**

Oil and condensate	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018(2P)
Reserves (1000 m3)	10823,6	10481,5	11554,0	11531,6	13471,1	12597,8	11932,1	11027,0	10230,30	8629,50
Production (1000 t)	776,2	720,4	664,4	599,9	600,7	593,2	670,2	804	744,5	792,7

Croatian Adriatic

In the Northern part of the Croatian Adriatic, 22 gas discoveries were made with estimated reserves of approximately 1.3 Tcfg. Currently, production is established from 19 gas production platforms, one compression platform and almost 51 wells. Annual production of gas amounts approximately 1,2 Bcmg. Several potential hydrocarbon plays have been identified, based on processed newly acquired 2D seismic data, which could lead to the new discovery of hydrocarbons after further additional seismic acquisition, interpretation and drilling of wells. Examples of selected newly recorded 2D seismic lines are presented below: No commercial discovery of oil has been found although two wells, Vlasta-1 and Jadran-13, had significant oil indication but for commercial and technical reasons exploitation has not been established. Potential gas accumulations are possible in the Plio-Pleistocene, Miocene and Cretaceous carbonate sections.

In November 2020, the discovery of Irena-2 (suspended) by Edison and INA in the block Isabella encountered 8-11 meters of gas pay in Mio-Pliocene sandstones and opens a new chapter for the exploration of the area (17) (Map 8.12).

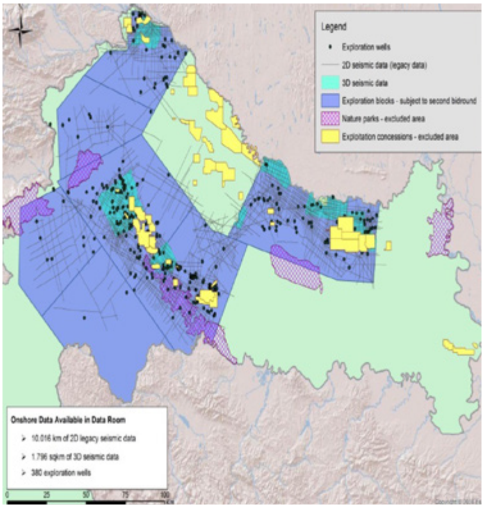
Pannonian Basin

According to HIS, the proven hydrocarbon system of the Pannonian basin contains multiple source reservoir and sealing rocks.

Long-term developments: Geothermal resources and power generation estimates

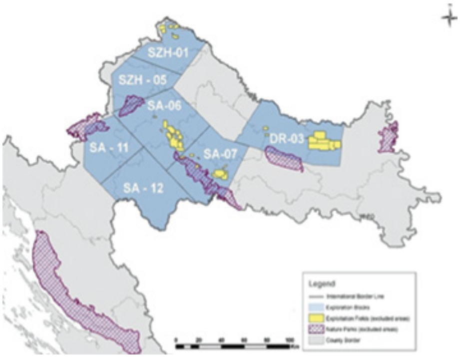
In 2019, the Croatian Hydrocarbon Agency released its annual overview that highlights the geothermal potential of the country (13) (Map 8.13). Five tenders have been conducted so far to allocate blocks for the exploration and exploitation of geothermal waters for energy purposes. Croatia has an above-average geothermal gradient (60% higher than the European average) and has the basic prerequisite for the use of geothermal water for energy purposes. The temperature rises by about 4.9 degrees Celsius with every 100m of depth on average. According to current estimates of existing geothermal sources, the current potential is 500 MW from geothermal energy. Some of these are sources of very high temperatures, usually above 120 or 150 degrees Celsius, which can be used for the production of electricity. Sources with lower temperatures of 60 or 80 degrees Celsius and higher, are suitable as hot water sources for district heating systems or in agriculture. Geothermal potential in Croatia has been proven in 40 wells.

Map 8.8 **Pannonian Basin: Legacy seismic 2D and 3D data and wells**



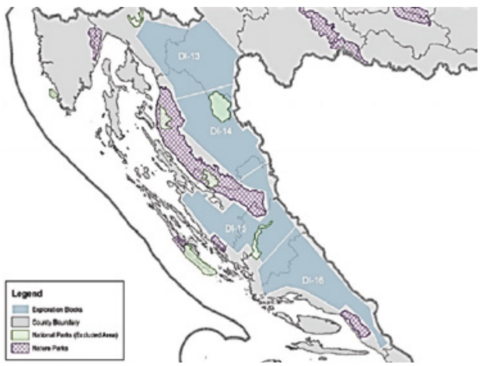
Source: Annual Report 2020, Croatian Hydrocarbon Agency (13)

Map 8.9 **Pannonian Basin: 2nd Onshore License Round O&G 2018** The 7 exploration blocks are located in northwest and central Croatia and in central Slavonia, with a total acreage of 14.272 km²



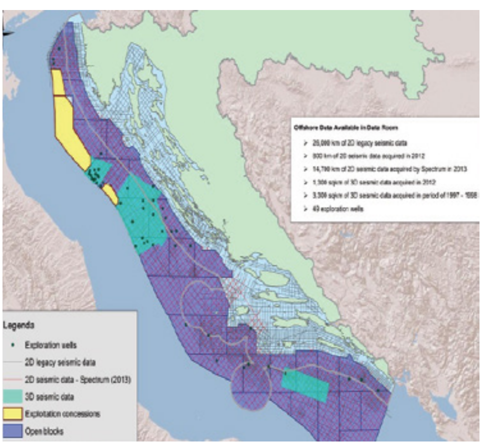
Source: Annual Report of the Croatian Regulatory Authority, 2018 (15)

Map 8.10 **Dinarides: 3rd Onshore License Round O&G 2019**



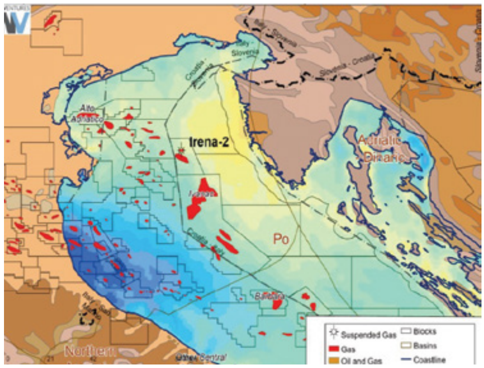
Source: Annual Report of the Croatian Regulatory Authority, 2019 (14)

Map 8.11 **Offshore Open-Door process**



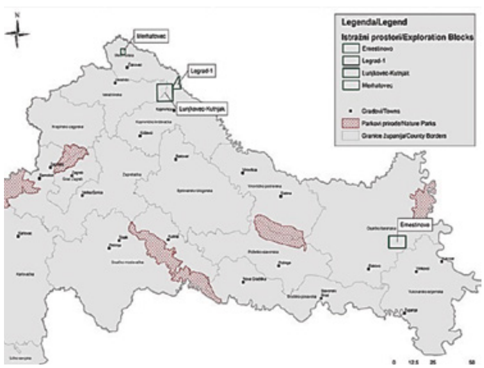
Source: Annual Report of the Croatian Regulatory Authority, 2019 (14)

Map 8.12 **Well location of Irena-2 in the Adriatic foreland**



Source: Courtesy of NVentures, 2020 (17)

Map 8.13 **Geothermal Potential bid round**



Source: Courtesy of NVentures, 2020 (17)

Bosnia-Herzegovina

Geologically the country can be divided into three areas, the External Dinarides, Internal Dinarides and Pannonian Basin. The Federation of Bosnia and Herzegovina extended until 2020 the 2019 bid round on four blocks in the external Dinarides and the Pannonian Basin (18) (Map 8.14). The strong Neogene extension of the Pannonian Basin developed depressions where sediments rich in organic matter were deposited, and these formed the source rock of the area.

Exploration activities ceased during the war in the 1990s but interest in oil and gas prospecting has returned. Modern technology may bring a significant upside with resources estimated at

4 billion barrels of oil buried between 4,000 and 8,000 meters and the large number of surface oil seepages present in both the Dinarides and the Pannonian Basin support this. The country has a long history of hydrocarbon exploration in the Majevica area, Pozarnica and Tuzla since 1889. Between 1973 and 1991 exploratory drilling took place in northern Bosnia by INA, which found oil in Tuzla. Similar plays were intensively exploited in neighbouring Croatia. Shell and Total expressed interest for exploration in the late 2010s while the legal framework was under modernization and that delayed the projects (19).

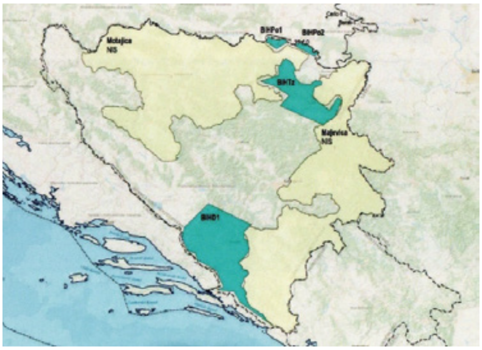
Shell previously held a reconnaissance permit for the Dinarides area from November 2011 and had considered a 25-year concession covering approximately 15,000 sq km in the west of the Mesozoic Dinaric carbonate platform, but withdrew from talks for a potential US$700 million deal in September 2015, shortly after it had agreed to purchase British Gas. Amoco conducted a study of Dinarides during 1989-91 and identified potential resources of 350 MMboe, at depths of 4,000 to 8,000m.

Licensing update in Bosnia and Herzegovina Onshore

The international Tender was launched by the Federal Ministry of Energy, Mining and Industry (FMERI) in January 2020 and led to the release of three blocks in the Pannonian Basin (BiHPo1, BiHPo2, BiHTz) and one block in the Dinarides Fold Belt (BiHD1) (Map 8.14). The total area is 5,115 sq km. The blocks have been available as exploration and production concessions, with a six-year exploration period split into two phases of three years each for the Pannonian blocks, against four years/two years for BiHD1.

The license round was announced after a study was conducted by Shell in February 2019 (20). The Federation hired the London-based IHS Global to provide consultancy services on the oil and gas concession project. It was planned initially to announce the winners of the round in June 2020.

Map 8.14 **Bosnia and Herzegovina 2020 bid round on four blocks in the external Dinarides and the Pannonian Basin**



Source: FMERI 2020

Serbia

As part of the Eurasian Plate, an orogenic system that is composed of the Alpine, Carpathian, and Dinaride orogenic belts, Serbia comprises various geological units from the Precambrian and Palaeozoic metamorphic rocks of its basement to marine Mesozoic sediment formations and Ophiolite melange (21). Oil and gas reserves compared to coal and lignite, are negligible and make less than 1% of the total geological reserves. The Southern Serbia region, covers around 30% of the country and contains oil shales of Upper Devonian to Lower Carboniferous age.

The area was extensively studied during the 1980s, while smaller reservoirs in the other parts of the country were found to be of negligible economic value. Recent studies show that more rational exploration may lead to the discovery of additional reserves of oil and gas in Serbia, particularly in the Pannonian Basin (22) (Map 8.15). As regards the remaining oil potential, the most promising are certain local depressions in the Banat Depression. Oil shales also have a considerable potential, particularly the Aleksinac deposit, but the exploitation of these non-conventional oil sources depends on various technological, economic and ecological factors.

Reserves

Estimated reserves of oil shale in the Republic of Serbia are about 85 Bbboe with up to 64 Bbboe of recoverable reserves, all concentrated within the Aleksinac, Vranje, Senonian Tectonic Trench, Valjevo, Western Morava, Kruševac, Babušnica, Kosanica, Niš and Levač basins, which are all located in the Central - Eastern part of the country (23) (Map 8.16). They may be found in few locations, but a higher degree of exploration has been achieved at the Aleksinac reservoir with a deposit of around 35 Bbboe.

There is some interest in oil shale mining. However, it depends on the prevailing crude oil price. Oil shale can be effectively used to produce this directly synthetic oil (by extraction), which can be used as fuel or upgraded by refining to petroleum product, while the residual part could be used in electricity generation (24). Environmentally, the project is acceptable since there is no need for extracted oil shale disposal. There are in total 21 oil shale deposits of various qualities and oil content. Serbian oil shale is of sapropel type (Aleksinac, Mionica and Petnica) and sapropel-coaly type. The two potentially exploitable large deposits, Aleksinac and Vina- Zubetin, are estimated to contain 35 and 15 Bbboe respectively. The Aleksinac deposit is equal to approximately 210 MMbb (33×106 m3) of shale oil. The Aleksinac deposit is Lower Miocene, about 30 metres thick, and is associated with coal layers.

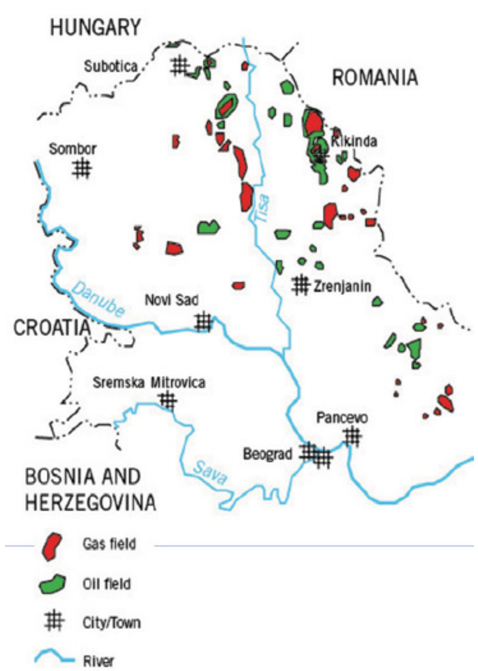
Serbian oil shale has around 20% organic matter, while the ash content ranges from 50% to 64% (25,26). Due to these properties, the Serbian oil shale cannot be burned directly at a fossil fuel power station as the rocks must first undergo a pyrolysis process. The significant depth of the reservoirs, up to 700 meters, excludes the possibility of open-pit mining, adding to the cost of production. For these reasons, fossil fuel extraction in Serbia has been limited to the more easily accessible and cheaply produced conventional coal, petroleum and natural gas.

Production and refining

Since 2009, NIS is the only company in the Republic of Serbia engaged in crude oil and natural gas research, exploration and production. Oil production in the Republic of Serbia is carried out in 63 oil fields with 666 wells using various extraction methods. The majority of NIS oil fields are located in Serbian territory, in the province of Vojvodina. However, NIS also has business operations abroad.

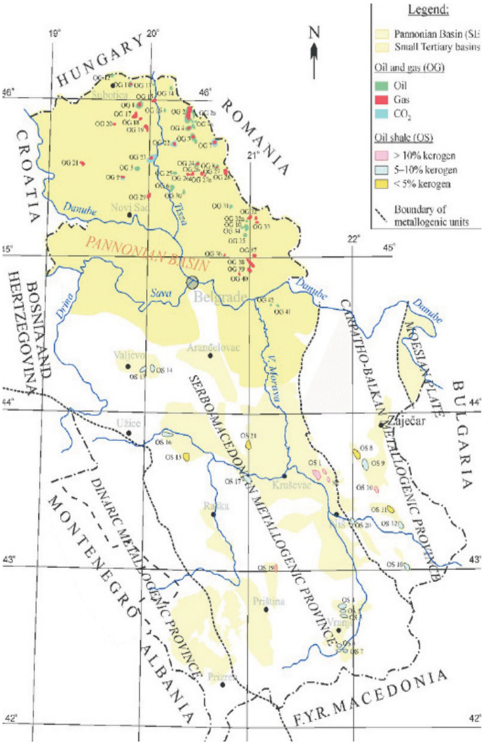
In 2011, it started to expand its business to Bosnia-Herzegovina, Romania and Hungary. NIS has two refineries, in Pančevo and in Novi Sad, as well as an LPG production unit in Elemir. The Company produces around 1.7 MMte of oil and gas a year, operating in Serbia, Angola and Bosnia and Herzegovina. The total volume of processed crude oil is nearly 2.1 MMt per year.

Map 8.15 **Serbian oil and gas fields**



Source: OGJ dec4, 2017 (22)

Map 8.16 **Oil and gas fields (OG) compared to the oil shale fields (OS) occurrences in Serbia (23)**



Oil and gas fields and oil shales in Serbia. OG 1 – Velebit; OG 2 – Mokrin; OG 2a – Mokrin jug; OG 3 – Kikinda; OG 4 – Kikinda-varoš ; OG 4a – Kikinda-varoš sever; OG 5 – Turija sever; OG 6 – Elemir; OG 7 – Srpska Crnja; OG 8 – Itebej; OG 9 – Srbobran; OG 10 – Jermenovci; OG 11 – Palić; OG 12 – Kelebija; OG 13 – Martoneš; OG 14 – Majdan; OG 15 – Novi Kneževac; OG 16 – Čoka; OG 17 – Čantavir; OG 18 – Gornji Breg; OG 19 – Ada; OG 20 – Bačka Topola; OG 21 – Ruski Krstur; OG 22 –Miloševo; OG 23 – Bečej; OG 24 – Karaaorrevo; OG 25 – Rusanda; OG 26 – Banatski Dvor; OG 26a – Banatski Dvor zapad; OG 27 – Begejci; OG 28 – Meea; OG 29 – Gospooinci; OG 30 – Zrenjanin; OG 31 – Boka; OG 32 – Velika greda; OG 32a – Velika Greda Jug; OG 33 – Banatsko Plandište; OG 34 – Janošik; OG 35 – Lokve; OG 36 – Banatsko Novo Selo; OG 37 – Nikolinci; OG 38 – Tilva; OG 39 –Mramorak; OG 40 – Mramorak selo; OG 41 – Sirakovo; OG 42 – Bradarac-Maljurevac. OS 1 – Aleksinac deposit; OS 2 – Bovan-Prugovac ; OS – Goč-Devotin deposit; OS 4 – Vlase-G.Selo; OS 5 – Stance; OS 6 – Buštrenje; OS 7 – Klenike; OS 8 – Vlaško polje-Rujište ; OS 9 – Vina-Zubetinac; OS 10 – Podvis-G. Karaula; OS 11 – Manojlica-Okolište; OS 12 – Mirinovac-Orlja; OS 13 – Šušuoke-Klašnić; OS 14 – Radobićka strana-Svetlak; OS 15 – Pekčanica-Lazac; OS 16 – Parmenac-Lazac; OS 17 – Odžaci; OS 18 –Raljin; OS 19 – Rača; OS 20 – Paljina; OS 21 – Komarane-Kaludra.

Montenegro

Montenegro covers an area of 13,812 km^2 and has 300 km of coastline. The central region hosts industrial activities, while the northern region is a mountainous area with significant coal reserves. The Montenegro hydrocarbon offshore prospects are positioned in both the Dinarides Thrust Belt and in the adjacent Adriatic-Ionian foreland basin with the Apulian Carbonate Platform mainly in Italian waters (Map 8.17). On the Italian side, large oil fields were discovered in thrusted Mesozoic carbonate traps, and gas fields in Tertiary reservoirs. Montenegro's offshore area is relatively underexplored, but has potential oil plays in Triassic, Cretaceous and Palaeogene clastics & carbonates and biogenic gas plays in the Pliocene, although the latter may be located in the deep-water area.

The stratigraphy of Montenegro's offshore area is dominated by similar Mesozoic to Middle Eocene rift to passive margin sequence with up to 3.5 km thick platform carbonates, shales and evaporates. This sequence contains a number of sources, reservoir and seal intervals, proven in wells and from outcrop studies. Beneath the carbonates, the Lower to Middle Triassic, primarily continental sequence, includes some marine clastic intervals with combined reservoir and seal potential. Drilled wells have shown gas-bearing sandstones and conglomerates which are associated with stratigraphic and structural traps. Recent marine seismic data (Map 8.18) show direct hydrocarbon indicators (DHI), positive AVO effects and gas chimneys (16).

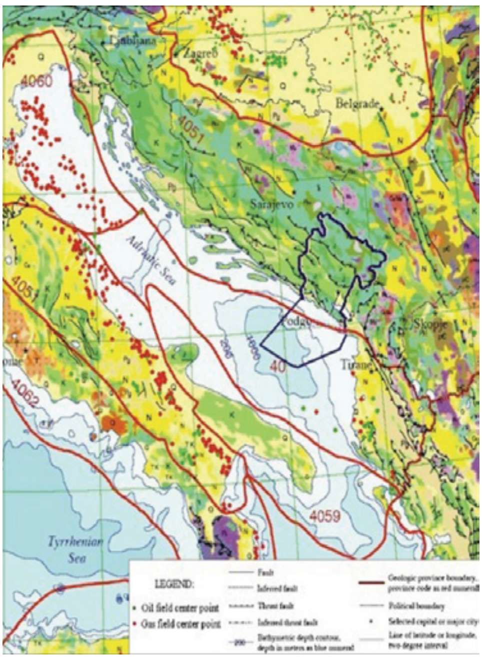
Licensing update on Montenegro

The country's First Offshore Round was launched in November 2013 with bids received from three consortia, Eni (Op) & Novatek, Marathon (Op) & OMV and Energean (Op) & Rockhopper. The 2013 Royalty/tax regime has an initial seven-year exploration period with a two-year extension and 20-year production period with a possible 10-year extension.

In September 2016, a total area of 1,228 sq km was awarded with 4 blocks to Eni (Op) and Novatek (4118-5, 4118-4, 4118-9 and 4218-10). Energean was awarded 2 blocks (4219-26 and 4218-30) in March 2017 (17). The surface of the blocks ranges from 62.44 to 304.84 sq km (Map 8.19). Both consortia aquired 3D seismic data across their acreage between late 2018 and early February 2019.

Map 8.17 **Geology, oil and gas fields and geological provinces of south-east Europe**

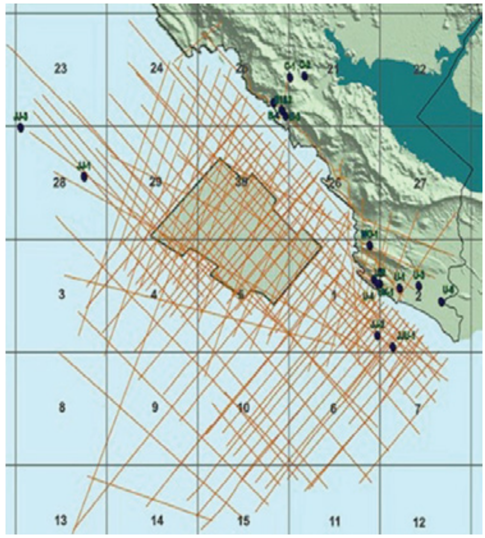
Although commercial deposits of oil and gas have not been found yet off Montenegro, in parts of the Adriatic Basin belonging to neighbouring Italy, Albania and Croatia, oil and gas have been found and commercially exploited for years



Source: U.S. Department of the Interior, Open File Report 97-470 (27)

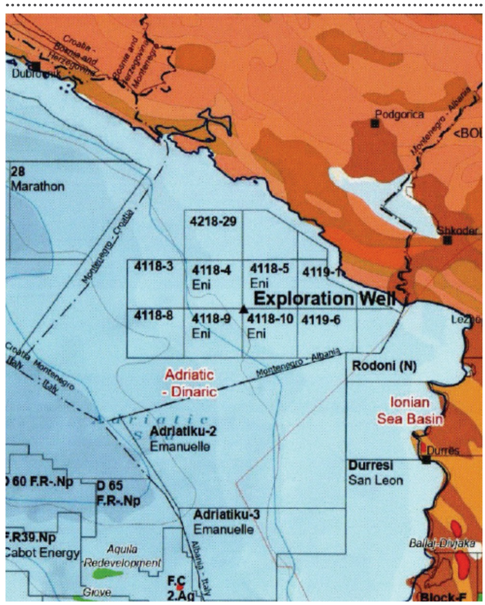
Map 8.18 **Data acquired offshore Montenegro**

Montenegro includes 2D seismic (orange lines), 3D seismic (green block) and exploration wells (blue circles). Block delineation is represented by grey lines. The deepest water is 600m.



Source: Ministry of Economy, Government of Montenegro (28)

Map 8.19 **Montenegro offshore acreage of the First Offshore Round and location of Eni-Novatek well (17)**



Source: Ministry of Economy, Government of Montenegro (28)

Albania

Albania was established as a hydrocarbon-bearing province as early as Roman times, when heavy oil and asphalts of Selenica mine were used in lamps. In 1918 the first oil discovery was made in Oligocene flysch in Drashovica. In 1927, 1928 respectively the Kucova and Patosi oil fields related to Messinian clastic reservoirs were discovered. The Albanides represent the main geological structure in the territory of the country. They belong to the Alpide belt and stretch between the Dinarides in the north and the Hellenides in the south within the Mediterranean belt. In Albania the oil and gas fields occur in both Cretaceous carbonate and Tertiary clastic reservoirs of the Dinarides fold belt. The Adriatic-Ionian Basin comes ashore in Albania where it is known as the Ionian Zone. Near the coast this is overlain by the post-tectonic 'Post Adriatic Depression', formed of Miocene to Recent molasse. The Ionian Zone crops out in southern Albania, where seven oil fields were discovered in the carbonates, demonstrating that basinal carbonates can be effectively charged with commercial volumes of oil. In Albania there is production from carbonate reservoirs in ten oil fields and one gas field, all in the pelagic Ionian Zone. According to the Albanian state-run oil firm AlbPetrol, the country has oil reserves of 220 MMbb, and natural gas reserves of 5.7 Bcfg. The daily oil production is around 23 MMbbl.

In July 2020, the government published the draft law on "Fiscal Regime for the Hydrocarbon Sector" which was submitted to parliament for review in June 2020 (29,30). The draft law aims to upgrade the current fiscal terms for each onshore hydrocarbon contract. These are currently regulated by Law No. 7746 on Petroleum (Exploration and Production) of 28 July 1993. Through this action the government is seeking to make the hydrocarbons law the primary basis for fiscal terms, via the proposed amendments. Terms that are not defined in this law are governed by Law No. 8438 of 28 December 1998 "On income tax" and Law No. 7746 of 28 July 1993 "On hydrocarbons (Exploration and Production)", as amended (Article 4.2).

Licensing update

The National Agency of Natural Resources (AKBN) may launch a tender in 2021 to offer Onshore Blocks 1, 6, 7, 8, A, B, C, D, E, F, in Panaja and Velca, plus Rodoni and Joni 5 offshore blocks; four dormant offshore licences are also likely to be offered - Adriatiku 2, 3 & 4, and Durresi (29,30) (Map 8.20). The size of the blocks to be offered ranges between 748 and 3,488 sq km. The offshore blocks are situated in shallow water close to the coastline. Albania's last licensing round was held in 2015, when six onshore and three offshore blocks were offered. Successful bidders were Shell (Block 4), Zenith Energy (Block C), and Delek Group subsidiary Navitas Petroleum (Dumre), but only Shell's Block 4 was awarded.

Short and mid-term developments

Dumre

In December 2019, ENI re-entered Albania after a 19-year absence, with the Block Dumre Production Sharing Contract (PSC) (587 sq km) situated north of Block 2 (Map 8.21). ENI is targeting deep sub thrust Mesozoic carbonates along a strike from the major Shpirag discovery. Commitments comprise technical studies, reprocessing vintage 2D seismic data, shooting 200km of 2D seismic data, and drilling one well to 6,150m to explore the Eocene and Cretaceous carbonates. The block is located in Elbasan and Lushnje regions, north of Kucova oil field, operated by Bankers Petroleum. Dumre is part of the 2019 bid round as part of AKBN which also included Block C and Panaja.

Shpirag wells

In 2002 Occidental drilled the Shpirag 1 ST2 (PTD 5,442m), and tested 37-40° oil from an Eocene/Cretaceous carbonate interval at a flow rate of approximately 1,200 bo/d. The well represented the first discovery in the internal part of the Albanian thrust belt. Previous discoveries were located closer to the frontal thrust (16).

Since this discovery a number of mostly successful appraisal wells have been drilled in Block 2 as follows:

- Shpirag 2 (2013, Petromanas, 5,553m) approximately 1.5km NNW of the discovery encountered around 800m gross pay, and tested 800-1,300 bbo/d and 2-5 MMcfg/d, with wellhead pressures between 1,700-3,000 psi,
- Shpirag 3 (Shell, 6,100m) approximately 1.4km SSE of the discovery, suspended in 2017 due to technical difficulties, and re-entered in 2019,
- Shpirag 4 (2018, Shell, 5,700m) located on the same well pad as Shpirag 2 confirmed "flow potential of several thousand" bbo/d during initial testing with extended testing also planned (17) (Map 8.22),
- Shell plans to drill the Shpirag 5 appraisal well on block 2 with a PTD of approximately 6,000m, scheduled to take 12 to 18 months to drill.

Shell has acquired the Petromanas assets and operates in Blocks 2-3 through the Upstream Albania BV with 100% equity. A new PSC is effective since February 2020 for Blocks 2-3. The new contract covers 3,100 sq km in the Ionian Basin of central Albania and restores around 900 sq km, which were relinquished in 2014. A new seven-year exploration period is split into three phases (3+2+2 years), with one well commitment to 4,000m per exploration phase, and a 25% compulsory area relinquishment at the end of each phase (16). Block 4, the most recently awarded, was ratified by the government in June 2018 after completing negotiations in early December 2017. License commitments comprise 3 Phases:

- Phase 1 (3 years) - acquisition and processing of 125km of 2D seismic data, reprocessing of 125km of existing 2D seismic data, and a minimum spend of US$8.5 million;
- Phase 2 (2 years) – acquisition of 300km of 2D seismic data and reprocessing of 200km of existing 2D seismic data, with an option to drill one well to 3,000m, and US$20 million minimum expenditure;
- Phase 3 (2 years) – drilling of one well to 3,000m and a minimum expenditure of US$14 million.

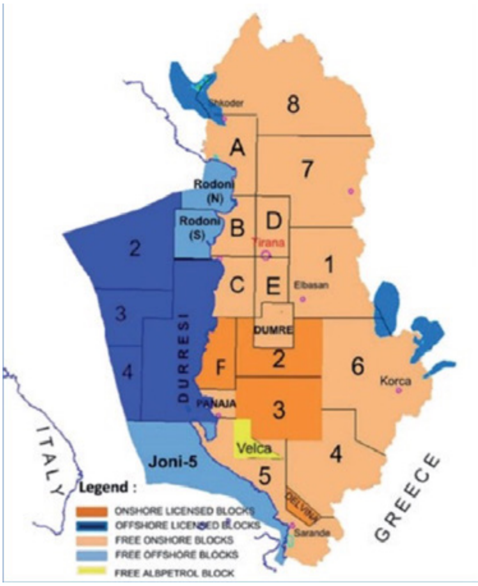
Block C and Panaja were still open for potential interest, according to the National Agency of Natural Resources (AKBN) in early October 2020, and they are expected to be released again alongside other open blocks in 2021. It was previously understood that Energy Development Group had bid for Block C (900 sq km) and Panaja (312 sq km), and was in discussions with AKBN during Q2 2020, but that discussion has apparently not developed (16). The blocks were offered from 19 September to 18 December 2019 in the 2019 Licensing Round which also included Dumre Block (587 sq km), which was awarded to Eni in March 2020.

AKBN has received one bid for onshore Block 5 from Cox Operating LLC as reported on 28 January 2019. The block covers 2,000 sq km in Sarande, Vlore, Gjirokaster and Tepelene counties, in SW Albania (16). The tender was approved by the Ministry of Infrastructure and Energy on 1 October 2018, and was open for applications from 8 October 2018 to 7 January 2019.

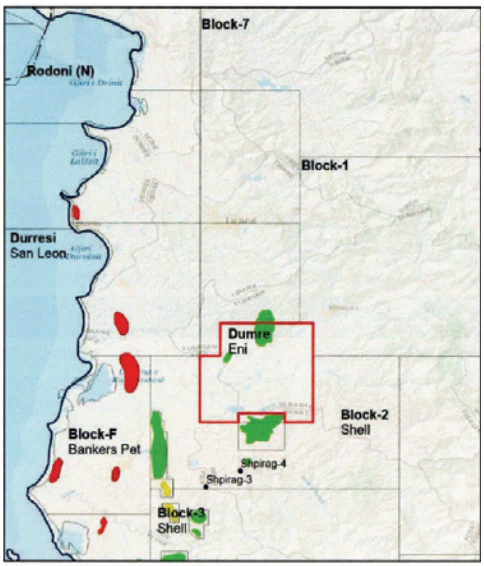
There was no application fee. Bid evaluation will be on the basis of proposed contract terms, namely work and financial commitments, state/contractor take, and training budget. If the Cox application is approved, the company will be offered a Production Sharing Contract (PSC) with a five-year exploration term which can be extended by up to two years. In the event of a commercial discovery, the PSC will advance to a 25-year production period. Block 5 was offered unsuccessfully in the 2015 Licensing Round and again via a public tender the following year.

The acreage contains the abandoned Finiq Krane heavy oil field, which was originally estimated to hold 1 MMbbo recoverable reserves (6.5 MMbbo in place, 10° API) in Cretaceous and Eocene Carbonates.

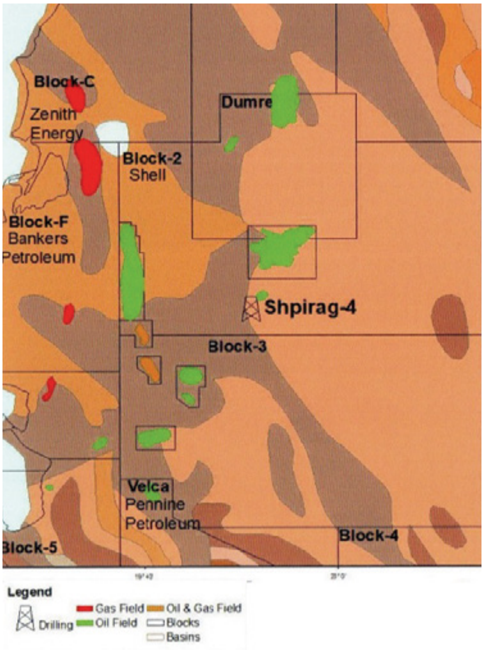
Map 8.20 **Albania's maritime and land concession areas (29)**



Map 8.21 **Land oil and gas fields with Dumre block position (17)**



Map 8.22 **Shpirag-4 location (17)**



Greece

Oil and gas exploration in Greece has recently been revived, especially following the discoveries in the Southeast Mediterranean. The gas field discoveries in Israel, Egypt and Cyprus in conjunction with the completion of the Trans Adriatic Pipeline (TAP) project, an important energy supply project for Europe, constitute turning points in the hydrocarbon sector. Hydrocarbon exploration in western and southern Greece will add to the country's status as a player, and the planned East Med pipeline would make Greece an important geostrategic area.

Many geological formations in the southern Ionian Sea and especially in offshore regions of Southwest and Western Crete resemble the Zohr field in Egypt, the fields of Calypso, Glafkos, Onesiphoros or Aphrodite in Cyprus, and the geological structures of Leviathan in Israel. If it proceeds, deep-sea exploration in Greek waters could see new advances in drilling, safety and production technology, because Greece's deposits are in waters as deep as, or deeper than, those in the southeastern Mediterranean and Black Seas.

Licensing update

Greece launched three International Licensing rounds in 2012, 2014 and 2017 (31,32). Greek parliament ratified eleven concession agreements for exploration and production between 2014 and 2019 (Map 8.23). Four concern the onshore blocks Ioannina, Aitoloakarnania, Arta-Preveza, Northwest Peloponnese. Repsol completed the Ioannina 400 km 2D seismic data acquisition in 2019 and processing in 2020. A decision was pending until April 2021 about whether to enter in the next phase entailing the commitment to drill one well. Aitoloakarnania, Arta-Preveza, Northwest Peloponnese are at an early stage of preparation of 2D seismic data acquisition. The seven other licenses concern the offshore Block 2, Ionian Block, Patraikos, Katakolon, Block 10, West of Crete, South West of Crete. These eleven licenses cover a total maritime area of 51,441 sq.km and a total land area of 16,831 sq.km. The offshore Block 1 (153 sq.km.) at the northern edge of the Ionian Sea, neigbouring Albanian waters, is not yet awarded. Similarly, the Sea of Thrace concession (1,600 sq.km) remains inactive.

Oil near-term development of the Epsilon, Katakolon and Patraikos fields

Prinos, Prinos North and Epsilon are currently the only producing fields in Greece, owned 100% and operated by Energean. Prinos, Prinos North and Epsilon oil fields are located in the Gulf of Kavala, 18 km south of the mainland of Northern Greece, in water depth of 30 to 38 metres. They have 38 mmboe 2P reserves and 62 mmboe 2C contingent resources, audited independently. Since 2015, Energean has successfully drilled ten wells in the fields of the Prinos Concession with its privately owned drilling rig "Energean Force", including two ERDs. Prior to that (2009-2015), Energean mobilised four jack ups which successfully drilled five wells. The Company managed to increase 2P reserves to 38 mmboe from just 2 mmboe in 2007. Prinos also has 62 mmboe 2C resources. In May 2021, Energean made FID on the revised Epsilon shallow-water tie-back development. Epsilon Phase 1 development capex is expected to be approximately $70 million, including construction of the Lamda platform and completion of the three pre-drilled production wells.

Production from the vertical wells of Epsilon is expected to start in 1H 2023. It should be noted that pre-FEED for the Prinos CCS project is underway and progressing well. Energean is the Operator in the Katakolo licence, in Western Greece, where has a 100 per cent working interest. The West Katakolo Exploitation area is part of the Katakolo block and covers 60 km2. NSAI has audited 14 mmboe 2P reserves and 4 mmboe 2C resources in the block. In August 2017, the Greek Government approved the Field Development Plan (FDP) submitted by Energean. Energean has planned to make FID or decide a farm down upon the approval of the necessary environmental studies. Energean will use Extended Reach Drilling (ERD) technology to drill from onshore to offshore reservoirs. In October 2021 Hellenic Petroleum (ELPE) and Energean have notified the Greek State that they intend to decided to withdraw from the West Patraikos licence, offshore western Greece. In January, 2020, the consortium had applied for an 18-month extension to complete second-phase work at the Gulf of Patras license. At the time, the consortium had cited insufficient port facilities for entry of the project's drilling facility and other equipment. The consortium would have had to conduct a first round of drilling in the winter of 2021-2022 or abandon the project. It opted for the latter. The project area covers 1,900 square kilometers. Katakolon is also an oil field under development. It contains approximately 180 metres of sour gas column, an oil rim of 120 meters in a large carbonate structure and may have undrilled deep potential. Energean has been exploring the block since October 2014, after the ratification by the Greek parliament of the License Agreement, signed with the Greek state on May 14th 2014. The company declared commerciality for the field after having finalized the reprocessing and interpretation of the existing 3D seismic data. In November 2016, Energean and the Greek State agreed the conversion of the exploration license for the proven West Katakolon offshore field to a 25-year exploitation license. In 2017, the Hellenic Hydrocarbon Resource Management (HHRM) approved the West Katakolon Field Development Plan (FDP). The development plan is targeting the 11 MMbb of recoverable oil that was discovered in the early 1980s by the then state-owned Public Petroleum Corporation. Energean is expected to drill the first well in 2022, after declaring force majeure in early 2020 because of the coronavirus epidemic. The deep-water drilling of the Patraikos license in western Greece was postponed for 2021. Hellenic Petroleum has not yet proceeded with concession agreements at four nearby ports, Patras, Kyllini, Aigio and Astakos as any port intending to host heavy drilling equipment needs to have included this in its official operating plan.

Gas near-term development in South Kavala

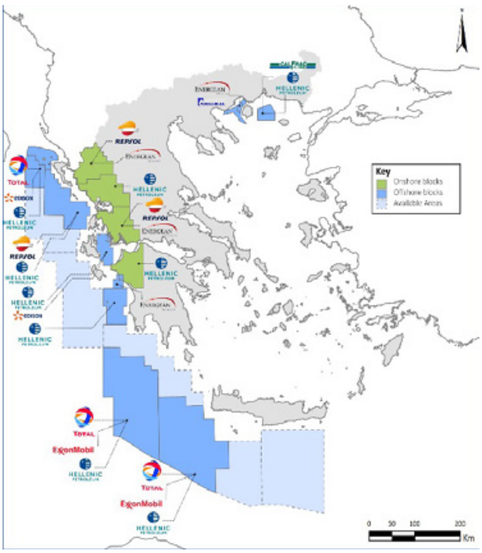
South Kavala gas field in the Thracian Sea is the only Greek gas field to have entered production. It is depleted today. The remaining gas reserves are approximately 3.6 MMcfg or 100 MMcmg), thus unsuitable for commercial production. The South Kavala field was discovered in 1972, and it was developed in parallel to Prinos field as a remote satellite during the period in 1979-1980. It contained approximately 1 Bcm of sweet gas and was produced with two wells at depths of 2,050 meters. It was developed to supply fuel gas to Prinos and to an onshore fertilizer plant (16,31). The depleted field may be suitable for conversion into an Underground Gas Storage (UGS) linked to the TAP pipeline. Conversion would require an initial minimum investment of US$400 million for an annual "working gas volume" of 1 Bcmg, with two cycles of ninety days of delivery per year. The UGS project was adopted by the European Commission as a Project of Common Interest (PCI) under Regulation (EU) No 347/2013 based on Guidelines for Trans-European Energy Infrastructures.

Long-term developments: gas and oil resource estimates and reserves

Western Greece and the northern territories of the Ionian Sea are oil-prone rather than gas-prone, with a few wells drilled during previous decades. This does not exclude the presence of gas in blocks like Block 10 (offshore Kyparissiakos Gulf) which is situated closer to the southern territories. The southern territories, Blocks West of Crete and Southwest of Crete, are characterized by ultradeep waters with average depths of 2,900 metres and maximum depths of 3,600 meters. They have not been drilled yet but the geological structures have significant similarities with gas reservoirs in Egypt and Cyprus and, to some extent, with those of Israel. For these two large blocks, the first exploration phase of 3 years started in October 2019 and consists of general studies and 2D seismic data acquisition. It will be followed by a second phase of 3 years during which selective 3D seismic data will be acquired before drilling begins in the third phase of 2 years' duration.

Open areas south of Crete (33,000 sq km) and in the central Ionian Sea (25,000 sq km) also show geological structures with similar build-ups and reef features (Map 8.24). According to HHRM, the estimated gas resources from 30 potential leads along the entire western Greece offshore domain, comprising the Cretan and Ionian areas, range between 70 and 90 Tcfg (12 to 15 Bboe) while resources from the potential leads only in the west, southwest and south of Crete range between 62 and 84 Tcfg. Although these estimates are based on geophysical-geological studies of the subsurface structures to be drilled after 2025, these volumes could significantly increase the potential of gas reserves of the Southeast Mediterranean pushing the edge of the future gas province further west (32). According to the same studies, the estimated oil resources from the Ionian Sea and the land concessions of western Greece may approach 2 Bbbl. Gas and oil in resevoirs hundreds or thousands of meters below the seabed of the Southeast Mediterranean is not the only expression of gas presence in the area. The presence of mud volcanoes and hydrates is deduced from the release of methane on the seabed surface or from the retention of methane in ice formations on the surface layers of the seabed (33,34,35,36,37). The above three varieties of methane presence are of interest to the international industry since gas could continue to bridge the transition to alternative energy sources for at least two more decades (Map 8.25).

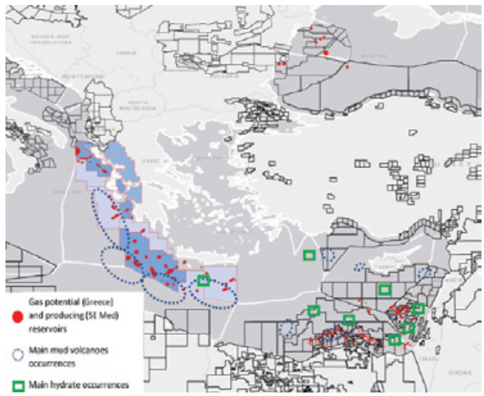
Map 8.23 **Licensing recent history of Greece (HHRM 2019) (30)**



Map 8.24 **Open areas south of Crete and in the central Ionian Sea** also show geological structures with similar build-ups and reef features as those of blocks West Southwest of Crete and Southwest of Crete. According to HHRM, the estimated gas or oil equivalent resources from these potential leads range between 6 and 8 Tcfg (1 to 1.3 Bbbloe)

Source: HHRM 2019 (31)

Map 8.25 **Geographical distribution of the concessions in the Eastern Mediterranean and Black Seas (black polygons)** Exploration concessions onshore and offshore Greece (deep blue). Areas of additional oil and gas offshore potential (light blue). Large geological structures south and west of Crete and in the Central Ionian Sea with possible build-ups and reef features similar to those of the fields bearing gas in the Southeast Mediterranean (in red), (modified after HHRM). The main occurrences of mud volcanoes and hydrates are also projected on the map



Source: EPOCH October 2020 (36)

Libya

In 2019 Libya held an estimated 37 Bboe (or 5.0 Bto) of total proved crude oil reserves (BP, 2020). Most of the country's proven oil reserves are held onshore. There are also some offshore oil fields, near the capital Tripoli. One of the most essential of Libya's crude oil blends is the Amna, with API gravity of 37.0, a high quality and low sulfur 0.17% crude oil. The oil grade is of excellent quality and requires a low level of refining maintenance and equipment. European refineries have for many years benefited from Libyan oil.

Back in 2009/2010 Libya's crude oil production varied between 1.75 MMbbl/d to 1.8 MMbbl/d. In the wake of the Arab Spring in 2011, which eventually led to the downfall of the Ghaddafi regime, oil production fell sharply to 516 MMbbl and has since not recovered to its earlier level. In 2019, average crude oil production reached 1,05 MMbbl/d, but in 2020 it bottomed to near 350 MMbb/d. Natural gas production recovered to approx. 9.4 Bcmg in 2019 but still lags behind the levels achieved in the Ghaddafi era (> 15.0 Bcmg per year).

Oil and gas demand are expected to rise again over the coming years as the Libyan civil war is coming to an end with a provisional Government of National Unity in place and elections scheduled for December 2021. However, the war has seriously impacted hydrocarbon production. Most of the economically viable oil fields are situated onshore and are expected to dominate the market. The Libyan oil and gas upstream market is moderately consolidated (38). The major companies include BP, Eni, the National Oil Corporation of Libya, Gazprom and Polskie Górnictwo Naftowe i Gazownictwo (PGNiG) SA.

Libya has five major onshore hydrocarbon basins, three in the east and two in the west (Map 8.26 and 26a). The Sirte Basin is the most productive, containing 16 giant oil fields and accounting for about two-thirds of Libyan oil production and 80% of the country's proven reserves. It is the youngest of the Libyan oil basins and is attributed to the collapse of a structural high that existed from around 400 Ma to 140 Ma. Early Cretaceous sediments in the basin were clastic, common in North Africa at the time, whilst carbonates predominated from the Late Cretaceous to the Tertiary, along with large quantities of organic-rich sediments, which give rise to two major source rocks, the Rachmat and Sirte Shales. The geological structures are dominated by a series of horsts and grabens, but there is also potential in Nubian sandstone stratigraphic traps in the southern Sirte Basin.

About 25% of oil production comes from the Murzuk Basin in south-west Libya, about 800 km south of Tripoli, which forms a large intracratonic basin between Algeria, Niger and Chad, and has some 3,000m of sediments from Cambrian to Quaternary age. The Silurian-aged Tannezuft shale is the major source rock, and hydrocarbons have been found trapped in large anticlinal features which are not heavily faulted. Due to its remote position, lying predominantly in the Sahara, it is relatively unexplored and the infrastructure is poorly developed, but a number of important discoveries have been made there, including the giant Elephant field, which in 2010 was producing an average of 126 MMboe/d.

The western Ghadames Basin stretches into neighboring Algeria where the sediment thickness reaches about 7,000m and where the majority of the basin's discovered reserves are located in Silurian and Devonian rocks. Areas of particular exploration potential in this basin include late Ordovician glacial deposits. The Cyrenaica Platform in north-east Libya to the east of the city of Benghazi has no commercial discoveries, but has potential in the form of a series of troughs and uplifted blocks.

A number of discoveries have been made offshore, which account for the remaining production, mostly from the Pelagian Shelf Basin near Tripoli. Success rates for offshore discoveries are higher than onshore and the area is considered highly promising, although predominantly for gas. There is also gas potential in the Jurassic and Cretaceous of the offshore Sirte embayment.

Licensing update

On 10 December 2019, the Tripoli-NOC (or NOCL) signed an agreement with Total sanctioning the French giant's acquisition of Marathon Oil's stake in the Waha Oil consortium (16). As part of the accord, the NOCL has stated that Total will invest up to US$650 million in the consortium's assets, which will include the development of the giant North Jalu Field in Concession 59, alongside development projects on the NC98 concession. The programmes are expected to create an additional 180 MMbboe/d of production. An additional US$150 million signature bonus will be allocated to social programmes. The deal was first announced on 2 March 2018, with both Total and Marathon reporting that the transaction had been concluded, and was effective from the 1st of January 2018. The agreement saw Total's subsidiary Elf Aquitaine SAS, acquire Marathon Oil Libya Ltd, which held 16.33% equity in Waha. It also marked

Marathon's country exit, with the company having been involved in Libya and the Waha Oil group since the 1960s.

The confirmed addition to Total's portfolio has seen the company greatly expand its footprint in the country and in particular, gain a stronghold in the Sirte Basin. Waha operates 11 concessions across the Basin, including those containing the giant Jalu and Waha fields. Gross daily output in H2 2019 has been around 350 MMbboe/d, having risen from a low of around 50 MMbbo/d in Q1 2017. Total has doubled net production in Libya to over 63 MMbboe/d, from a 2017 average of 31 MMbboe/d. Aside from Waha the company also holds stakes in the offshore Al Jurf Field (through Mabruk Oil) and the onshore El Sharara Field in the Murzuq Basin (through Akakus Oil). Equity in Waha is split: Total (16.33%), ConocoPhillips (16.33%), Hess (8.16%) and the NOCL (59.18%).

On 21 May 2018, the Joint Oil Exploration, Exploitation and Petroleum Services Company (JOINT OIL) launched an invitation seeking investors for its Libya-Tunisia JEZ acreage of around 3,000 sq km (40). (Map 8.27). The Joint Oil area, is located in the Libya-Tunisia Joint Exploration Zone (JEZ). The company is seeking investors in order to carry out exploration activity, with up to six prospects in proven plays in the Cenomanian to Eocene, identified on the eastern Libyan portion of the acreage. Joint Oil is also seeking interested parties to develop the western Tunisian section, which contains the Zarat Field. A draft unitisation agreement is available, with the field extending into the adjacent Zarat license, held by ETAP (99% +Op) under the Tunisian licensing regime. The Joint Oil block is regulated by an Exploration PSA and PSA, which is separate from the Libyan and Tunisian fiscal regimes. The DPSA will be applied should a party wish to develop Zarat. The Field was discovered by Marathon in 1992, when Zarat 1 encountered oil & gas in the Eocene El Gueria limestones.

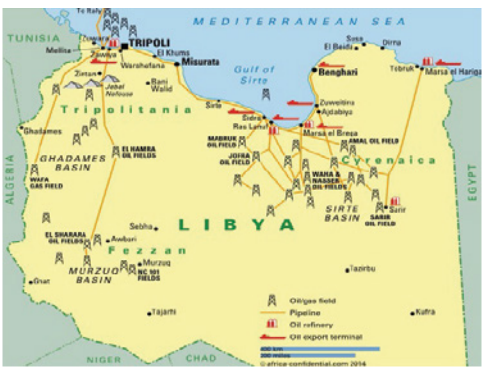
A data room opened on 21 May 2018 and closed on 21 September 2018, updating 2C contingent resources estimates for Zarat to 49 MMbblo and 389 Bcfg. A deadline of 17 October 2018 was set for the submission of bids. The opportunity was then marketed by Beicip-Franlab. The area, which lies in 80-120m WD, was originally created thanks to an agreement of the Libya/Tunisia continental shelf delineation on 8 August 1988. The accord, which also ratified the 1988 delineation, created the JEZ and the JOINT OIL JV. Equity in JOINT OIL is held 50/50 between Libya Oil Holding Ltd (LOHL) and Entreprise Tunisienne d'Activités Pétrolières (ETAP). To date, Six NFWs have been drilled on the acreage.

The last successful well, Zarat Nord 1, was drilled in 2010, after EPSA signed up on November 7 that year, and Canadian Superior Energy (subsequently Sonde Resources) in August 2008. The well proved the extension of the Zarat Field northwards into the block. Zarat Nord 1 tested three intervals of the Eocene El Gueria limestones, flowing gas and condensate at rate of 750 bboe/d and 8 MMcfg/d; net pay was 73m. In 2013, Sonde cancelled a farm-in deal with Viking Energy, after Viking failed to secure the prerequisite US$40 million bank guarantee as part of the deal. Sonde filed for bankruptcy on 2 February 2015 and was delisted from the TSX on 11 February 2016.

In late May 2018, the Tripoli-NOC assigned 13 blocks across the country, to its wholly owned subsidiary Zallaf Libya Oil & Gas. The awards are a result of discussions in September 2017, when provisional approval to assign the blocks was given. In the Ghadames Basin, ALEPCO's former 8,900 sq km NC168 licence was awarded, alongside a 4,300 sq km block to the SW, enclosing the 1958 B1-49 oil discovery. Further south, the former NC210 block (formerly held by Woodside and then GDF Suez) was allocated; it contains the Atchan oilfield. In the Murzuq Basin, the former NC174, 187, 190 and 200 blocks were awarded. They surround and enclose the Sharara and El Feel complexes. In the Sirte Basin, part of the NC 126 (former Sirte-operated), 206 and 208 (former Woodside and then GDF Suez-operated) areas were conferred upon Zallaf.

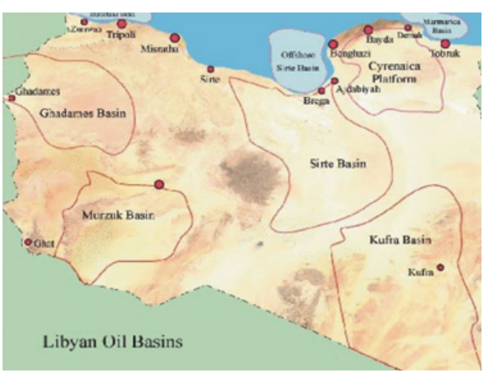
Zallaf was established as an NOC subsidiary in 2013, although its registration was completed by the eastern-based Council of Ministers at the time. It was formally registered as a company by the Tripoli-NOC in Q3 2017 and has its base in Sabha, in the SW of the country. In March 2017, Eni made a gas and condensate discovery with the B1-16/3 NFW Gamma prospect located on the offshore Area D concession, 50 km from the Tunisian border and about 140 km north-west of Tripoli (40) (Map 8.28). The well was spudded on 4 January 2017 and was drilled in 150m of water, reaching a TD of 2,981m. The well lies just 5 km north of the Bahr Essalam field and 15 km south-west of Bouri field. The well targeted Eocene Metlaoui carbonates, which were successfully tested in two intervals. This is the first offshore discovery in Libya since Eni's A1-1/1 well in May 2015, which also encountered gas and condensate in Metlaoui carbonates. The company believes that the Gamma well could produce 7,000 boepd. The drilling of the Gamma prospect targets existing infrastructures. Eni operates the Area 'D' with 50% equity, in partnership with the NOC (50%, carried).

Map 8.26 **Oil and gas producing fields in Libya**



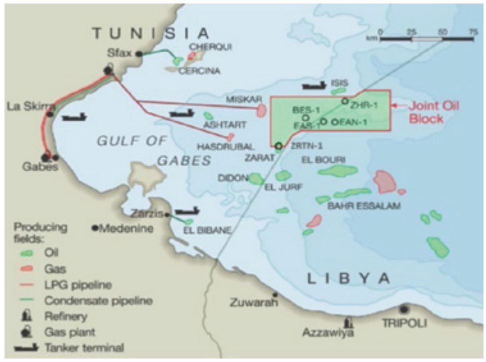
Source: Africa-confidential

Map 8.26.a **Oil and gas basins in Libya**



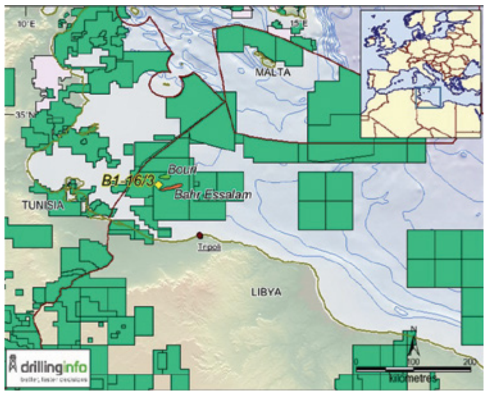
Source: Africa-confidential

Map 8.27 **Libya-Tunisia Joint Exploration Zone (JEZ) acreage of around 3,000 sq km**



Source: JOINTOIL (40)

Map 8.28 **Libya-Tunisia Joint Exploration Zone (JEZ) acreage of around 3,000 sq km**



Source: JOINTOIL (40)

Egypt

The oil and gas midstream industry is expected to grow slightly in the forecast period due to a significant expected increase in the production and consumption of gas and the increase in investment into the pipeline and LNG terminal infrastructure. However, oil consumption in Egypt declined steeply in 2017-2018, which is expected to impede the further growth of the crude market. Under this environment, the country appears to be moving towards more of an open-door policy or concession agreements, particularly with respect to Mediterranean acreage (41) (Map 8.29).

Egypt has an extensive pipeline network across the country, especially near the Nile river, where most of the population of the country lives. New pipelines are in the proposal stage and are expected to be completed over the coming years (42). The volumes to support the development of Egypt will come from the surplus gas production of about 550 MMcfg/d at the giant Zohr field, where production reached 2.7 Bcfg/d at the end of 2019. Supply to the three LNG trains in Egypt – Shell-operated Idku T1 and T2 and Eni-Damietta T1 – will produce 1.42 million tons a year in 2020. In addition to these volumes, West Nile Delta, Nooros, Atoll and Baltim South West will all be major contributors to this ramp up.

Map 8.29 **Egypt's gas fields (41)**

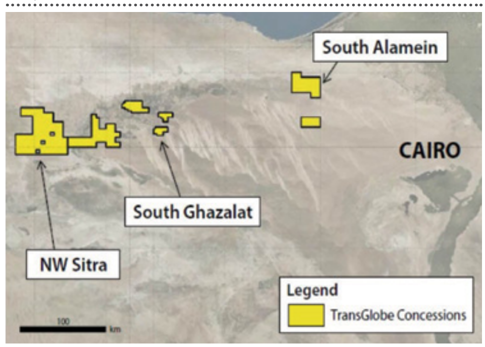
Exploration update in Egypt

In the recent past, Egypt has awarded relatively unexplored blocks to majors. Today, Egypt's hydrocarbon production is set to rise to about 2.2 MMboe/d in 2020, especially due to the supply additions from Baltim South West and Zohr. With this, Egypt will have brought most of the resources discovered to date online. Further ramping up and maintaining production levels will be contingent upon future discoveries.

Western Desert

In November 2018 TransGlobe Energy announced a potential light oil discovery with its SGZ-6X exploration well on the South Ghazalat concession in Egypt's Western Desert, about 300 km west of Cairo (43) (Map 8.30). The company has now confirmed this to be a major discovery, having announced that on test the well yielded a combined 3,840 bblo/d of light (35–38° API) oil from three intervals in the Cenomanian Upper and Lower Bahariya Formations. Based on these positive results, it will begin preparing a development plan for the field. Its acreage position in the Western Desert is approximately 4,625 sq km covering three concessions: South Alamein, North West Sitra and South Ghazalat. The company committed to a work programme of US$8 million at South Ghazalat in the first phase, consisting of 3D seismic data and two wells. It acquired about 400 sq km of 3D seismic data during 2015 and with the completion of SGZ-6X has met the financial commitments for the current exploration phase. The 1,414 sq km South Ghazalat PSC is located in the prolific Abu Gharadig Basin, a deep east–west trending asymmetric graben, about 300 km wide, running 60 km north–to-south.

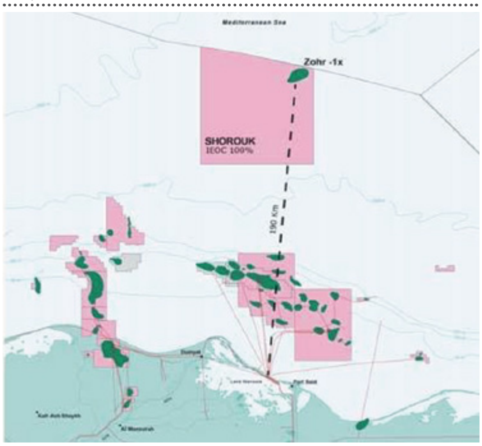
Map 8.30 **Western Desert recent discoveries (43)**



The Zohr Gas Field

The Zohr field is a Lower-Middle Miocene carbonate reservoir located offshore the Nile Delta, hosting a biogenic gas accumulation deriving from a Tertiary source rock, which is sealed by the Messinian Evaporitic complex (also known as the Rosetta Formation) (16,44,45). The field was brought online in 2017 and produces over 2.5 Bcfg/d. Rystad Energy estimates that the field holds a total of 3.55 Bbbloe recoverable. Zohr Gas field is located within the 3,752 sq km Shorouk Block, within the Egyptian Exclusive Economic Zone (EEZ), in the Mediterranean Sea (Map 8.31). The field is situated more than 150km from the coast. Eni owned a 100% stake of the Shorouk license through IEOC Production, and the property is operated by Belayim Petroleum Company (Petrobel), a joint venture between IEOC and Egyptian General Petroleum Corporation (EGPC). Eni was granted approval for the Zohr Development Lease by the Egyptian Natural Gas Holding Company (EGAS) in February 2016. The deep-water gas field started production in 2017 and reached full production capacity in 2019. Zohr 1X NFW well is located at a water depth of approximately 1,450m. The exploration well was drilled to a total depth of 4,131m and encountered 630m of hydrocarbon column. The field was successfully appraised in February 2016 by drilling the Zohr 2X appraisal well, approximately 1.5km east of the exploration well. The appraisal well was drilled at a water depth of 1,463m and to a total depth of 4,171m encountering 455m of continuous hydrocarbon column. It produced approximately 44 MMcfg/d during the production test.

Map 8.31 **Shoruk block**

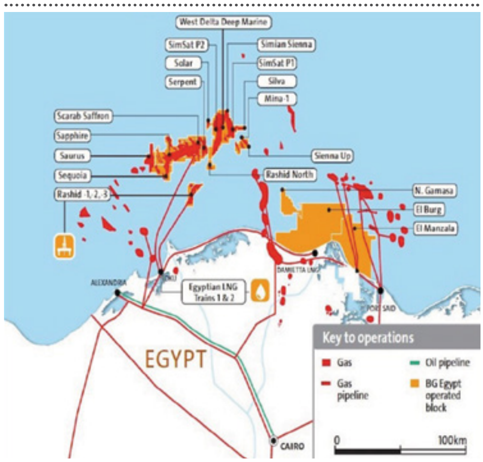


Source: ENI annual report

The Nooros Gas Field

The Nooros gas and condensate field is located in the shallow waters of the Nile Delta, approximately 120km north-east of Alexandria, and is part of the Abu Madi West development license (16,46) (Map 8.32). Through its subsidiary IEOC Production BV, Eni holds a 75% interest in the Abu Madi West development license, while BP holds the remaining 25%. The field is operated by Petrobel, which is jointly owned by IEOC (50%) and the Egyptian General Petroleum Corporation (50%). Eni is further developing the field to reach a maximum production capacity of 160 MMbbloe/d in 2017. Production from the Nooros field plays a key role in reducing dependence on gas imports. To further explore the field, the Nidoco NW3 well was drilled from onshore to reach the field reservoir. Similar to the discovery well, the exploration well encountered a 65m-thick gas-bearing sandstone layer of Messianian age. In February 2016, another deviated well, Nidoco North 1X, was drilled from onshore and encountered a gas-bearing sandstone reservoir of the Messinian age with a thickness of more than 43m.Petrobel discovered the Nooros field by drilling a directional well to a depth of 3,600m. The well struck a 60m-thick gas-bearing sandstone reservoir of Messinian age. The field was brought online in July 2015 and it is currently producing about 1.2 Bcfg/d. Rystad Energy estimates that the field holds over 650 MMbbloe of recoverable gas reserves. The field is estimated to contain 15 Bcmg in place (530 Bcfg), along with associated condensates.

Map 8.32 **The Nooros gas and condensate field** in shallow waters of the Nile Delta, approximately 120km north-east of Alexandria (46)

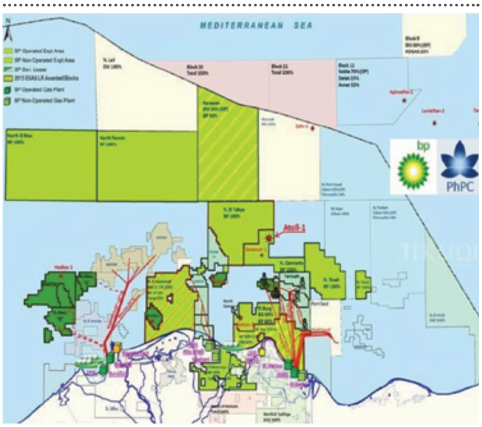


The Atoll Gas Field

The Atoll gas field is a significant discovery lying in the North Damietta Concession offshore the East Nile Delta (41) (Map 8.31). The field was developed by BP, which holds 100% equity in the discovery. It started production in February 2018. Pharaonic Petroleum

Company, a 50/50 joint venture between BP and EGPC, discovered the Atoll gas field in the North Damietta offshore concession in 2015. The exploration well encountered 50m of gas pay in an Oligocene sandstone reservoir and the field was brought online in 2016. Rystad Energy estimates the field to hold about 250 MMbbloe of recoverable gas reserves. The Atoll gas field is a significant discovery lying in the North Damietta Concession. It started production in February 2018. BP expects to increase its gas production in Egypt and achieve 2.5 bcfg/d of production by 2020, which represents approximately 50% of the country's current gas production. The field is estimated to contain approximately 1.5 Tcfg and 31 MMbbl of condensates. An estimated 350 MMcfg/d along with 10 M b/d) of condensate is transported to the Egyptian domestic gas market. The exploration well was drilled to a depth of 6,400m and encountered approximately 50m of gas pay in high-quality sandstones. It is the operator's , Pharaonic Petroleum Company, a joint Venture between Egypt's state-owned Egyptian General Petroleum Corporation (EGPC) and BP Egypt, second most significant Oligocene discovery in the area after the Salamat discovery of 2013. The drilling site is located 15km north of Salamat discovery, 80km north of the city of Damietta, and 45km north-west of the Temsah offshore facilities. Full field development is estimated to cost $3bn, while the first phase was developed with a $1bn investment.

Map 8.33 **The Atoll gas field in the North Damietta Concession in the East Nile Delta (41)**



Long-term developments: gas and oil resource estimates and reserves

The Egypt oil and gas midstream market is moderately consolidated. Some of the major companies include Egyptian Natural Gas Holding Company, Eni S.p.A, Royal Dutch Shell PLC, Egyptian General Petroleum Corporation, and BP PLC. Recovering prices, strong demand from the transportation industry and modern developments in oil and gas exploration and production are some of the factors driving Egypt's oil and gas market growth. As of 2019, the total length of major gas pipeline infrastructure in the country was around 2,700 km (17,41). New projects have been proposed that are expected to increase the growth in the sector further. In 2020, the Cyprus-Egypt gas pipeline was still in the proposal stage, and is expected to be laid from Cyprus offshore gas field to the Damietta Segas LNG Terminal, Egypt. The length of the proposed pipeline is approximately 310 km.

Oil production fell in 2019 by 1.6%, from 34.2 MMto in 2018 to 33.6 MMto. Domestic oil consumption decreased by 1.2%, year-on-year, from 757 MM bbl/d in 2018 to 743 MM bbl/d in 2019. Higher oil production requires transportation and pipeline capacity and is expected to increase slightly in the forecast period due to rise in oil production and rising investment in the sector.

During 2017-2018 Egypt saw a significant increase in the production of natural gas. It is expected that the country may invest further in its midstream sector and increase overall profits. Production of natural gas increased, by 10.9% from 58.6 Bcmg in 2018 to 64.9 Bcmg, in 2019. Domestic consumption of gas fell by 1.1%, from 59.6 Bcmg in 2018 to 58.9 Bcmg in 2019. The increase in natural gas production is intended for export and is expected to provide a boost to the oil and gas midstream sector. The West Nile Delta LNG Terminal was under construction in 2020, with an intended capacity of 1.4 Bcfg.

Late 2019 licensing update in Egypt

East Damanhur Onshore: On December 2019, the Egyptian House of Representatives (HoR) ratified the concession agreement for the East Damanhur Onshore block, located in the Nile Delta Basin (16). The 1,418 sq km area lies immediately west of the Disouq PSC (Wintershall Dea 50% equity) in the Nile Delta Basin. Work commitments include expenditure of US$28 million and the drilling of seven wells. An US$11 million bonus will be paid upon PSC signature. Wintershall Dea, will operate the concession.

El Burg Offshore: On December 2019, the HoR ratified the agreement for the award of the Notus development lease (DL) as a carve-out from the shallow-water El Burg Offshore concession, located in the Nile Delta Basin. Notus contains the HPHT Notus 1 discovery, drilled by BG to 7,200m TD in January 2014. The well is one of the deepest drilled in the country in 30m WD. The well encountered gas in the Oligocene, with BG (now Shell) estimating a GIIP figure of 1.2 Tcfg & 26 MMbbl of condensate. Equity splits in the lease upon award are understood to be Shell (30%), BP (20%) and EGAS (50%, carried).

Red Sea Block 4: On December 2019 three blocks were awarded following competitive bids. Block 1 went to Mubadala Petroleum (30%) and Chevron; Block 3 went to Shell; and Block 4 was pre-awarded to Shell (70% +Op). IS THIS CORRECT? The combined minimum investments across the three blocks will total US$326 million, over an area of approximately 10,000 sq km with a maximum nine-year exploration phase.

Deepwater Nile Delta Basin block: On June 2020, the HoR approved the draft concession agreement for the Star Offshore block, located in the deepwater part of the Nile Delta Basin. The concession is operated by ExxonMobil. The 5,700 sq km area lies in 1,200-2,400m WD, immediately north of ExxonMobil's recently signed North East El Amriya Offshore concession and west of the Zohr Field. PGS has acquired a recent 2D seismic data across the block, as part of its "MC2D-EGY2018" 2D seismic programme.

Nour North Sinai Offshore: This block was awarded to Eni in August 2018, with the company making the Nour 1 ST gas discovery in April 2019. The second PSC, North Marakia Offshore, was signed by ExxonMobil on 27 January 2020. The licence is located in the frontier western Mediterranean sector, offshore Apache's North West Razzak concession.

West Sherbean Onshore Nile Delta: In June 2020, the HoR approved the draft concession agreement for the West Sherbean Onshore block. The block was pre-awarded to Eni on 12 February 2019, following the announcement of the winners of the EGAS 2018 International Bid Round. The 1,538 sq km block lies immediately west of and adjacent to the Abu Madi and Nile Delta concessions, in which Eni holds 50% and 37.5% equity respectively, and adjacent to BP's North El Matariya concession. It also lies immediately east of DISOUCO's Disouq PSC and north of SDX Energy's South Disouq licence. Preliminary work commitments include expenditure of US$18 million and two wells during the initial exploration period. A US$5 million signature bonus will be paid. Eni will operate the concession with 50% equity, in partnership with BP (50%).

Cyprus

Until 2015, discoveries of deltaic river channeled hydrocarbon systems prevailed in the Southeast Mediterranean. These systems were almost exclusively clastic reservoirs, like "Aphrodite" coming either from the sediments of the Nile, or from materials of other rivers channeled into the Levantine basin (such as Leviathan, Tamar, Karish, Tanin) (17,41,44,46). The discovery of the Zohr field in Egypt, changed the overall drilling approach by targeting carbonate structures.

In 2017, Total was the first cpmpany to target Zohr-type fields in the EEZ of Cyprus with Oenesiphoros West-1 well on Block 11 (Map 8.34,8.35). The well was announced as non-commercial having discovered less than 500 Bcfg. However, the well proved the existence of other Zohr-type reservoirs and a working petroleum system in the Cypriot EEZ. The discoveries of Calypso 1 and Glaucus 1, which followed, validated this play. The Zohr carbonate structure (Miocene/Cretaceous) covers an extensive area of around 100 sq km and is perceived to be a satellite structure to the Eratosthenes continental block. This led Cyprus to sign in 2008 a bilateral Maritime Demarcation Agreement with Egypt. It also led to the discovery of Glafkos in 2019, as well as the licensing of Block 7 to Total in 2019 and the planning of an intense drilling program in the area. Further Eni has announced plans to return to the Soupia 1 prospect of Block 3.

Licensing update in Cyprus

Following the discovery of Aphrodite (4.1 Tcfg) in 2011, drilling at the end of 2014 by Eni/Kogas in Block 9 resulted in two dry wells ('Onasagoras' and 'Amathousa'). Total decided to relinquish Block 10 in 2018 due to the lack of drillable prospects. In 2019 Block 7 was awarded to Total/Eni with Total also farming into Blocks 2, 3, 8 and 9. More drilling operations were planned in early 2019 for Blocks 2 and 3, as well as a geophysical survey in Block 11.

Eni discovered the "Calypso" field (2.5 to 8 Tcfg) in Block 6 in 2018, proving the extension of the Zohr-type carbonate play in Cyprus' EEZ. (Total's previous attempt in 2017 to drill the 'Onesiphoros' well in Block 11, had non-commercial results). In 2019 the consortium of Exxon/Quatar Petroleum drilled the 'Delphyne' well in Block 10 with non-commercial results. The second well drilled by Exxon/Quatar in Block 10 led to the discovery of the Glaucus field (5 to 8 Tcfg) (Table 1).

The size of Cyprus's 13 offshore blocks ranges from 1,439 sq km to 5,733 sq km (with an average size of 3,907 sq km). Only Block 1 has a size exceeding 5,000 sq km (an elongated block with proximity to the coast). Blocks 4, 10, 11,12 and 13 define maritime boundaries.

Table 8.2 **Gas discoveries offshore Cyprus**

2011	Block 12	Aphrodite	Noble-Delek-Shell 4.1	Tcfg
2014	Block 09	Onasagoras	Eni-Kogas	
2014	Block 09	Amathousa	Eni-Kogas-	
2017	Block 11	Onesiphoros	Total -	
2018	Block 06	Calypso	Eni	2.5-8 Tcfg estimated
2019	Block 10	Delphyne	Exxon/QP-	
2019	Block 10	Glaucus	Exxon/Q	5-8 Tcfg in place

Gas near-term development of Aphrodite, Glaucus and Calypso

The operator companies licensed by the Republic of Cyprus expected to carry out a two-year exploratory drilling programme starting in late 2019, but operations were delayed until 2021 due to Covid-19 pandemic and the consequent international economic slowdown. Exxon's programme in Block 10 with one well and that of Total and Eni in Blocks 6 and 8 with three wells is to be revived In November 2019, Cyprus' Ministry of Energy issued the country's first exploitation licence for hydrocarbon production in Block 12 to Noble Energy as operator (35%), Shell 35%, Delek Drilling 30%. After Chevron acquired Noble Energy in the last quarter of 2020, a program of drilling in Cyprus and Israel was revived. The development phase of the Aphrodite gas field by Chevron, comprises the drilling of production wells and the installation of an FPSO (Floating, Production, Storage and Offloading) platform to collect the gas, process and treat it. The development of the field will take place in 2023 and gas is to start flowing in 2025. Initial planning was targeting an appraisal/development well, completion of Front End Engineering and design delivery of the gas in accordance with the Field Development Plan, and a mechanism for the distribution of the natural gas proceeds between the consortium and the Republic of Cyprus.

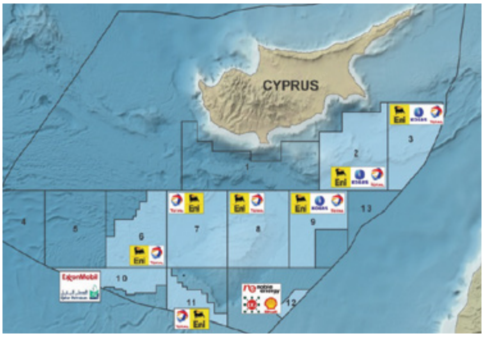
Gas near-term development and LNG import terminal

An import terminal for liquefied natural gas (LNG) will be built on time. The government has licensed China Petroleum Pipeline Engineering, Metron, HudongZhonghua Shipbuilding and Wilhelmsen Ship Management to construct a floating storage and regasification unit (FSRU) and related infrastructure. Imports should start by the end of 2022. The monopoly of DEFA on gas imports needs to be resolved by making it a semi-government organization, before it can be granted any licenses by the Cyprus Energy Regulatory Authority (CERA).

Long-term developments and gas pipelines

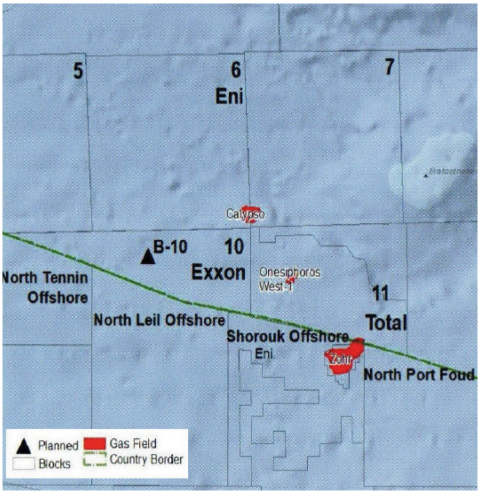
Gas may be delivered to the local and nearby markets and several options are being studied such as a subsea pipeline to Egypt for export through existing LNG production facilities, or a subsea pipeline to Cyprus for the local market, or a subsea pipeline to Jordan for the local market. Gas may also be delivered to remote locations.
An important infrastructure project concerns the gas transportation from offshore Cyprus/Israel to Cyprus, then onto mainland Greece (via Crete) and finally to Italy via mainland Greece and the IGI (Italy- Greece Interconnector) pipeline. This "East Med Pipeline" was approved as a Project of Common Interest (PCI) under the European Energy Infrastructure Package (EIP) and currenly a detailed feasibility study is in progress.

Map 8.34 **Licensing recent history of Cyprus**



Source: CHC, 2020 (48)

Map 8.35 **Location of discoveries in Cyprus offshore**



Source: Nventures, 1018 (17)

Israel

Petroleum has been exploited in Israel since ancient times. Remains of asphalt collected along the Dead Sea shore were identified in Egyptian mummies dated to about 200 B.C. Modern commercial exploitation of hydrocarbons began in the 1950s with the discovery of the Helez oil field in the southern Coastal Plain of Israel (49,50) (Map 8.36). The Helez success promoted drilling activity throughout the country, but until the 1990s only small quantities of oil and gas had been discovered and produced.

In 1999 the focus of exploration was shifted from the onshore systems to the Levantine Basin (49) (Map 8.37). In the following decade, 11 natural gas fields were discovered offshore in water depths ranging from 200–1,600 m. One of them, the MariB field, began production in 2004 and the Tamar field in 2013. Israel's maritime territory lies within the Levantine Basin, which contains up to 10,000m of Mesozoic and Cenozoic rocks above a rifted Triassic-Lower Jurassic terrain. The two most prominent tectonic features are the Levantine Basin and Margin in the west and the Dead Sea rift in the east. Most of the hydrocarbon accumulations found in Israel are associated with these two tectonic provinces. Other important structural elements are the Syrian

Arc fold belt in central and southern Israel, the Sinai-Negev dextral, strike-slip faults, and the normal fault system of the Galilee.

Licensing update on Israel

On 17 February 2019, the Ministry of National Infrastructures, Energy & Water Resources (MIEWR) granted the 413 Aya oil exploration licence to Arbel Oil and Gas Exploration Ltd, a wholly owned subsidiary of Gulliver Energy Ltd, and Shapir Engineering and Industry Ltd. (51). The onshore licence covers an area of 275 sq km and is located around the city of Eilat in southern Israel. It lies in the Aravah region along the border with Jordan and stretches from the Red Sea in the south to the Grofit Kibbutz in the north.

The licence will be valid for an initial three-year term. The JV has committed to the re-processing of existing 2D seismic data (176 km), acquisition of new 3D seismic data (65 sq km) and the drilling of an exploration well. Arbel Oil and Gas Exploration Ltd. operates the licence with a 50% stake, with Shapir Engineering and Industry Ltd holding the remaining 50% interest.

<u>1st Offshore Bidding Round (OBR)</u>

The country's 1st Offshore Bidding Round (OBR), was formally announced by the Ministry of National Infrastructures, Energy & Water Resources (MIEWR) on 15 November 2016. The acreage offered in the bid round had been drawn-up for competitive bidding on the recommendation of the Petroleum Council and comprised 24 blocks, located close to the large gas discoveries (49) (Map 8.36). The Council's recommendation was based on an evaluation of the Levant Basin's petroleum system by Beicip-Franlab. The research had been commissioned by the MIEWR and found that at a best guess there were resources totaling around 6.6 Bbblo and 75 Tcfg as-yet undiscovered in Israeli waters. These are estimated to be found in four different plays extending from the shallow margins in the east to the deep basin in the west. Companies were able to bid for any number of blocks, with a bid bond of US$70,000 payable per block. Bids were evaluated based on the proposed work programme (90%), technical competence (5%) and signature bonus (5%). ONGC Videsh Ltd operates the acreage with a 25% interest and is partnered with Bharat PetroResources Ltd (25%), Indian Oil Corp Ltd (25%) and Oil India Ltd (OIL) (25%).

On 9 April 2017, MIEWR granted ONGC Videsh Ltd an offshore exploration licence. The awarded licence covers Block 32 (356.98 sq km), which is located to the NW of the I/13 Dalit production lease. It will be valid for an initial three-year exploration term and is extendable to a maximum period of seven years,blocks are up to 400 sq km in area and are in water depths of around 600-1,800m.

<u>Second Offshore Bidding Round (OBR2)</u>

OBR2 had been formally announced by MIEWR with a call for bids on 28 November 2018 (17,52) (Map 8.38). The acreage offered for bidding in OBR2 included a total of five zones (A to E), three of which received bids. Zones A, B, C and D include four blocks each, while Zone E includes only three. Each block measures up to 400 sq km. The decision to market the areas in multi-block, multi-licence zones was made in order to allow better correlation between the exploration areas and subsurface geological structures that potentially contain oil and gas reservoirs. The Ministry hoped that larger stakes will allow more efficient subsurface evaluation and would increase the attractiveness of the zones to investors. Companies were able to bid for any number of zones, with a bid bond of US$70,000 payable per bid per Zone. However, in order to attract as many new bidders as possible, the Ministry of Energy decided to limit the number of licenses granted to any one company to eight licenses. Bids for each Zone were evaluated separately, based on the proposed work programme, technical competence and signature bonus.

On 28 October 2019, the Israeli Ministry of Energy awarded a consortium comprised of Cairn Energy (33.34%, operator), Pharos Energy (33.33%) and Ratio Oil (33.33%) eight offshore exploration licences following a recommendation by the Petroleum Council (16). The awarded licences comprise Blocks 39, 40, 47 and 48, collectively offered as Zone A, as well as Blocks 45, 46, 52 and 53 (Zone C). They are located south of the Tamar and Leviathan gas fields and will be valid for an initial three-year exploration term. Extensions for two successive periods of two years are available, subject to the completion of the proposed work programme. The joint venture has committed to reprocessing 2,700 sq km of 3D seismic data for Zone A and not less than 1,486 sq km of 3D seismic data for Zone C.

On 28 October 2019 the Israeli Ministry of Energy awarded a consortium comprising Energean Oil & Gas (80%) and Israel Opportunity-Energy Resources Ltd. Partnership (20%) four offshore exploration licences following a recommendation by the Petroleum Council. The awarded licences comprise Blocks 55, 56, 61 and 62, collectively offered as Zone D. They are located SE of the Tamar and Leviathan gas fields and will be valid for an initial three-year exploration term. Extensions for two successive periods of two years are available, subject to the completion of the proposed work programme. The joint venture has committed to the reprocessing of at least 675 sq km of 3D seismic data.

3rd Offshore Bid Round (OBR3)

Following a three-month bidding period, Israel's 3rd Offshore Bid Round (OBR3) for exploration in Block 72 closed on 23 September 2020. The Ministry of Energy received two bids, one from Energean Oil and Gas and one from a consortium comprising Noble Energy and Delek Drilling. The single exploration block covers an area of 257.4 sq km in the northern part of the Israeli EEZ, along the disputed maritime border with Lebanon (Map 8.39) (17). It is in close proximity to the Karish and Karish North gas fields and previous geological analysis shows the potential for similar gas accumulations in the block area. A bond of US$50,000 was payable per bid. Drilling in the licence area is not permitted, and it is not yet known whether such permission will be granted. The license terms include a commitment to analyse the available geological and geophysical data and identify potential drilling targets within 18 months of granting.

Onshore awarded blocks

On 27 May 2019, MIEWR granted Shapir Engineering and Industry Ltd. the 414 Achinoam exploration licence. The onshore licence covers an area of 337 sq km and is located near the city of Arad in central Israel. It lies about 30km west of the Dead Sea along the southern border of the West Bank.

The licence will be valid for an initial three-year term. In total, three wells have been drilled in the block, with the last one in 2001 (Uza 1). All of them were plugged and abandoned after failing to encounter hydrocarbons. Despite this, a working petroleum system has been proven in the area, with several small oil and gas fields being located to the SE of the licence. Shapir Engineering and Industry Ltd operates the licence with 100% interest. Zion has reported that Megiddo-Jezreel-1 had been plugged and abandoned after several attempts to stimulate and flow test at the Triassic Mohilla dolomites failed. Further funds have now been raised to test shallower zones, possibly in Jurassic carbonates, where live oil reported during drilling and logs (17).

Chevron acquisition

On 5 October 2020, Chevron announced it had completed the acquisition of Noble Energy, following the approval by Noble's shareholders on 2 October 2020. Chevron will acquire all of Noble's outstanding shares in an all-stock transaction valued at approximately US$4.1 billion based on the closing price of Chevron's shares on 2 October 2020 (being the last business day before closing) of approximately US$71.19 per share. This price corresponds to less than US$5/boe per proved reserves. In Israel, Noble operates six offshore production leases in the Levant and Pleshet Basins. These include: I/7 Noa (47.059%), I/10 Ashkelon (47.059%), I/12 Tamar (25%), I/13 Dalit (25%), I/14 Leviathan South (39.66%) and I/15

Leviathan North (39.66%). While plugging and abandonment operations are currently being carried out on the Noa and Ashkelon leases (together comprising the Yam Tethys project), the Tamar and Leviathan leases recorded gas production at around 780 MMcfg/d and 621 MMcfg/d respectively in Q1 2020. The Dalit discovery has so far not been developed. Noble's only other Middle East asset is 35% operator share in the Block 12 exploitation licence offshore Cyprus. The block contains the undeveloped Aphrodite gas field, which is estimated to hold unrisked contingent and prospective resources of 4.5 Tcfg and 9 MMbbl of condensate.

Production update in Israel

Leviathan Field

In August 2020, joint venture partner Delek Group reported that as part of the gradual ramp-up of production capacity in the Leviathan Field (Levant Basin) offshore Israel to 1,200 MMcfg/d, production capacity stands at around 940 MMcfg/d (16). During Q2 2020, operator Noble Energy (now Chevron) commenced commissioning of turbo expanders to bring the Leviathan platform to maximum production capacity and the company expects that the run-in phase of the turbo expander systems will be completed in Q4 2020, subject to receipt of regulatory approvals from the Ministry of Energy. The turbo expander project was suspended in June 2020, to prevent air pollution.

Noble Energy announced on 31 December 2019 the start of natural gas production from the Leviathan Field after receiving the final approval from the Ministry of Environmental Protection on 30 December 2019. The original Leviathan Field Development Plan (FDP), which was approved in June 2016 by the authorities, includes a subsea system that connects eight production wells to a fixed offshore platform, with a tie-in onshore in the northern part of Israel. The initial phase of development consisted of four development wells (including the completion of two existing wells for production - Leviathan 3, 4, 5, and 7) and the construction of the offshore platform with an initial capacity of 1.2 Bcfg/d. In the second phase, four additional wells would be drilled, and the capacity of the platform will increase to 2.1 Bcfg/d. The cost for the initial development was budgeted at US$3.5 billion, with the full development estimated at a total cost of US$5-6 billion.

Delek reported in March 2019 that the joint venture was considering expanding the production capacity in the field from 1.2 Bcfg/d to 1.6 Bcfg/d in the first phase and from 2.1 Bcfg/d to 2.4 Bcfg/d in the second phase. A budget of US$25 million has been allocated for a Front-End-Engineering and Design (FEED) study to examine the various expansion options. A Final Investment Decision (FID) on expanding gas production from the field was expected during 2020. The expansion options will consider the use of an LNG plant in Egypt (Idku terminal) or the building of a floating LNG facility. Further development of the field will require a gross investment of some US$2.5 billion. At present Noble Energy Mediterranean Ltd operates the Leviathan Field with a 39.66% interest and is partnered by Ratio Oil Exploration (1992) Ltd Partnership (15%) and the Delek Group through its subsidiary Delek Drilling Ltd Partnership (45.34%).

Karish field

In December 2020, Energean plc entered into an exclusivity arrangement to acquire Kerogen's 30% shareholding in Energean Israel Ltd. The transaction includes Karish, Karish North & Tanin fields (gross 2P reserves 3.5 Tcf g+ 100 MMbbl of condensate) plus exploration blocks 12, 21, 23 & 31.

In October 2020, Energean provided an update regarding its development of the Karish gas field offshore Israel on the I/17 Karish lease. The company stated that, the pipe rack modules have been successfully lifted on to the "Energean Power" FPSO hull at the Sembcorp Marine Admiralty Yard in Singapore as well as mooring lines offshore Israel. The Karish development project currently remains on track to deliver first gas in H2 2021. The

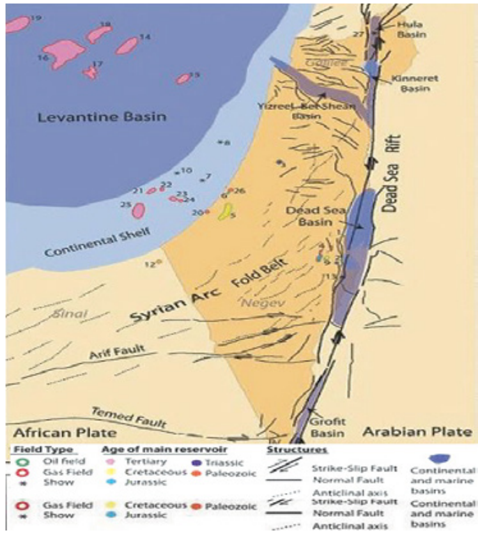
FPSO is being constructed by TechnipFMC under an US$1.36 billion contract signed in March 2018. With its 775 MMcfg/d capacity, "Energean Power" will enable Energean to maximise the recovery of reserves (16). In late March 2020, Energean had completed operations on the Karish Main development wells (KM 1, KM 2 & KM 3), with Stena Drilling's "Stena DrillMAX" drillship. Drilling of the three wells was completed in October 2019 and completion operations started the following month (Map 8.39). All three development wells have successfully flowed during clean-up operations, confirming that each will be capable of delivering up to the design limit of 300 MMcfg/d.

The Zeus-1 well, lying between the Karish and Tanin fields, was drilled at 1,400-1,800 m water depth. The Karish Field and I/17 Karish lease are operated by Energean Israel Ltd, a joint venture consisting of Energean (70%) and Kerogen Capital (30%). Energean Israel is the operator of the Karish and Tanin leases in the prolific Early Miocene submarine fan deposits of the Tamar Sands. Karish North, is located about 80 km north-west of Haifa and a few kilometres south of the maritime border with Lebanon. Initial in-place estimates of gas are between 1 and 1.5 Tcfg, reservoired in high quality sands, with a gross hydrocarbon column of 249m. Karish North was spudded on 15 March 2019 in waters over 1,700m deep. Karish North lies only a few kilometres north of the Karish field, discovered in 2013, which contains more than 280 MMbbloe 2P reserves, and 40 km from the 2.2 Tcfg Tanin field. Plans for the joint development of these two fields using a Floating Production Storage and Offloading unit are underway.

Oil shales

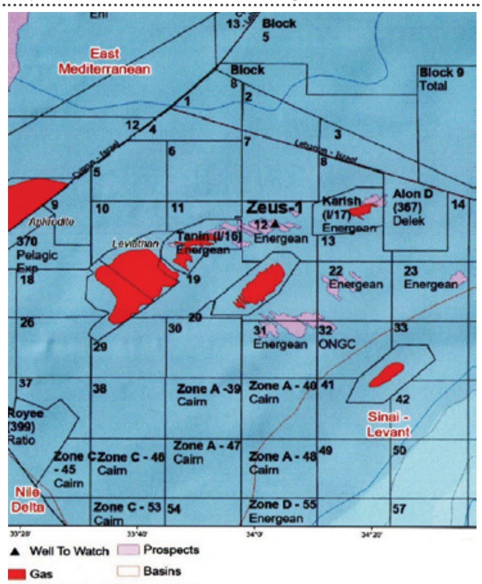
Israel's Ministry of Energy announced on 18 February 2020 that it will not grant new licences for the exploration and production of oil shales in the country.

Map 8.36 **Map showing the main tectonic elements and petroleum occurrences of Israel (50)**

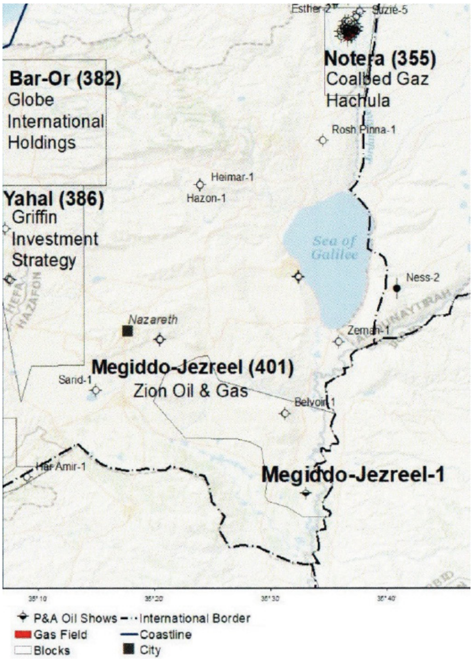


Source: Nventures, 1018 (17)

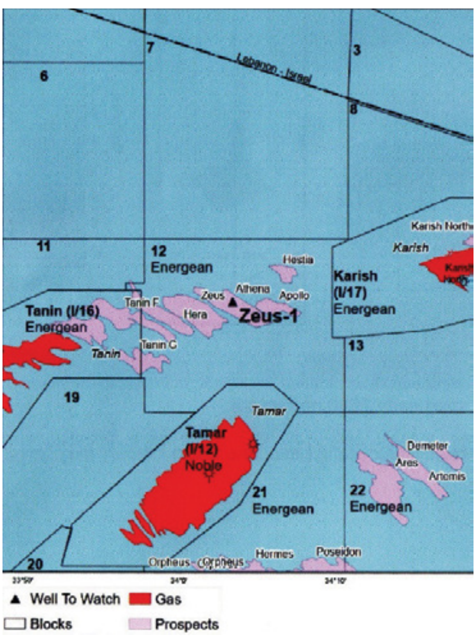
Map 8.37 **Second Offshore Bidding Round (OBR2) (17)**



Map 8.38 **Second Offshore Bidding Round (OBR2) (17)**



Map 8.39 **Karish development and Zeus-1 well (17)**



Lebanon

Lebanon is surrounded by proven hydrocarbon discoveries to the west and south, including especially the neighboring offshore fields of Tamar, Leviathan and Aphrodite. The country extends along the eastern coast of the Mediterranean Sea and lies within the same Mesozoic basin area in which major oil and gas fields have been found in the offshore and onshore Levant Basin, the northern part of the Arabian shield in the Nile Delta Cone and southern Levantine Basin, offshore Cyprus and Israel (53,54,55).

The country is poorly explored onshore due to topographic challenges although some countries in this region have been producing hydrocarbons for a very long time. The offshore blocks in the west display large, simple 3-way dip and 1-way fault closed structures based on modern 3D seismic data similar to the Nile-derived deep-water fan, high quality sandstone. Additionally, oil-prone source rock directly underneath these plays suggests another petroleum system, probably thermogenic.

Licensing update on Lebanon

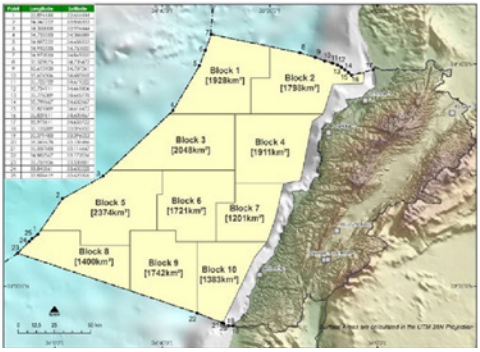
In January 2017, the Lebanese government launched its 1st offshore licensing round and released 10 blocks ranging from 1,201 sq km to 2,374 sq km, and averaging 1,790 sq km (55) (Map 8.40). The round was covering parts of the Levantine basin, the Latakia Ridge and the Mesozoic coastal margin but was delayed by 3 years due to the preparation of related legislation. In February 2018 the international consortium of Total (operator, 40%), Eni (40%) and Novatek (20%) signed two Exploration and Production Agreements (EPAs) for Blocks 4 and 9 (56). The consortium committed to drill one well per block in the first three years of a total duration up to 10 years on the license.

In April 2020 the Lebanese authorities announced the 2nd offshore licensing round for blocks 1, 2, 5, 8 and 10 which are located in three distinct major geological zones. Block 1 falls within the Latakia Ridge zone in the NW of the EEZ , Blocks 5 and 8 are located in the deep Levant Basin in the SW and Blocks 2 and 10 cover parts of the Levant margin in the NE and SE. The blocks have been chosen to offer a number of different play types, as each zone is characterized by different structural and sedimentological features. Companies were requested to form consortia of three or more companies to submit applications before the end of April 2020. The licensing round was accompanied by 3D seismic data.

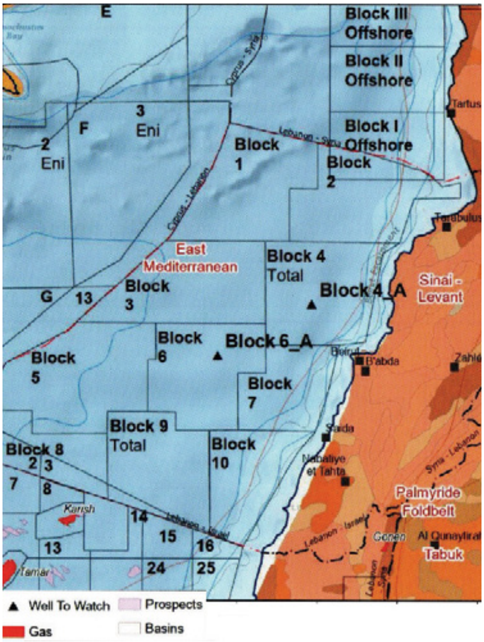
The first well, Byblos-1 (Map 8.41), was drilled in Block 4 in 2020 (February to April) and evaluated the possible presence of hydrocarbons at approximately 1,500 metres of water depth to a total depth of 4,076 meters, 30 km North of the Beirut coast. Gas shows were encountered in the Oligo-Miocene but the main objective Tamar sandstone, the reservoir for the Israeli fields to the south, was absent (57). This sand is believed to have been derived from the proto-Nile delta to the south, and may not have been transported this far north.

The obligation to drill in Block 9 (Map 8.41), was for the period before May 2021. Non satisfaction of the contractual commitments may lead to a penalty of US$40 million. The main prospects of Block 9 are located more than 25km from the disputed area with Israel, which covers less than 8% of the block's surface. The consortium confirms that the exploration well does not interfere with any field or prospect located in the disputed area.

Map 8.40 **Blocks of the 1st Licensing Round of Lebanon (54)**



Map 8.41 **Map showing the location of Byblos-1 well and proposed well on block 9 (57)**



Syria

The onshore part of Syria belongs to the northern Arabian Platform, while the offshore part belongs to the African Plate, comprising the Palmyride area, the Euphrates Fault System and the Sinjar area in northeast Syria (58). The Palmyride is a Late Paleozoic/Mesozoic depocentre trending northeast across central Syria where the present topography is the result of Tertiary compression (58) (Map 8.42). During the last 60 years exploration in Syria mainly developed in the major Late Paleozoic and Mesozoic sedimentary basins. Source and reservoir rocks were deposited during major regional extensional periods in the Late Paleozoic and Mesozoic. Main traps were created in the Senonian, by block faulting and by anticlines associated to Cenozoic inversions of normal faults (Map 8.43). Entire regions are still not explored. New targets in Paleozoic and Mesozoic petroleum systems present themselves. Known traps are the NE-trending Palmyrides and the E-W Sinjar anticlines. The Euphrates Graben tilted fault blocks may be surmised (60). Stratigraphic traps may include the Paleozoic siliciclastic succession, isolated

Cretaceous carbonate build-ups, or Jurassic-Cretaceous carbonate platforms and karsts, and offshore siliciclastic basin-floor fans.

Reserves

Just a few years ago, Syria was producing 400 MMbbl/d oil, and possessed the largest hydrocarbon reserves of any producer in the greater Levant region except Iraq, with 2.5 Bbbl of oil reserves. At the beginning of 2013, its reserves corresponded to 42 years of production at a rate of 164 to 168 MMbbl/d. All of the country's proven oil reserves are held onshore (61,62). Oil was first discovered in 1956 in Karatchok in a massive Cretaceous limestone at 3,155 m with more than 1 Bbbl of oil. It was only in 2010 that the first offshore acreage was offered when InSeis geophysical company acquired 5,000km of 2D data. Syria's proven, recoverable, conventional gas reserves were estimated in 2013, between 10.1 and 8.5 Tcfg, 0.2% of world reserves, and in the same range as those of Bahrein and Yemen at that time.

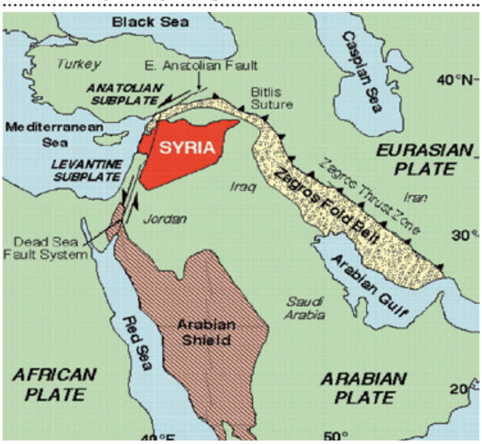
Licensing history in Syria

Oil and gas exploration and production has been concentrated within three geological provinces: The Palmyra Foldbelt northeast of Damascus, the Euphrates Graben along the river Euphrates, and the Sinjar area, including the Sinjar Trough and the Syria Foldbelt, close to both Iraq and Turkey in the northeastern part of the country (Map 8.44). The Euphrates Graben is the main producing area. The coastal basins cover approximately 8,500 sq km but the geology of the sedimentary basins is poorly understood. The first commercial seismic survey was acquired in 2005 and approximately 65,000 sq km were open for licensing onshore in 2011 (61,62). Shell, Total and Canadian company Suncor Energy have all suspended operations due to the situation in Syria, and Emerald Energy, a wholly-owned subsidiary of Chinese state-owned Sinochem which owns the other 50% in the Block 26, has agreed to issue a force majeure. Gulfsands intends to retain its 100 Syrian staff, hoping that when the present troubles will subside, they will be able to resume operations. In the mean-time, GPC continued to produce oil from the block itself.

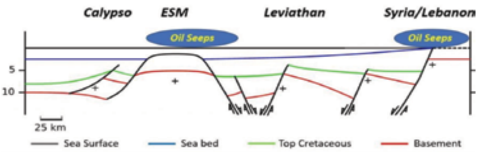
Production

Syrian oil production peaked in 1995 with 635 MMbbl/d. Since then, it has fallen steadily, albeit not dramatically, and in 2004 the average production was 536 MMbbl/d, down approximately 5% from the year before, while in 2011, the last normal year of production before a full-scale civil war broke out, production stood at 353 MMbbl/d as reported by the BP Statistical Review of World Energy (63). Since then crude production has steadily declined. Reported data are for 171 MMbbld in 2012, 59 MMbbl/d in 2013 and 24 MMbbl/d in 2018. The initial decline was probably due to diminishing reserves in the Euphrates fields that began producing in the 1980´s. In the late 2000s, there were two productive oilfields within the PSC area, which lay in the extreme north-east corner of Syria, bordering Iraq to the south. Khurbet East was discovered in June 2007 and commenced commercial production only 13 months later, while the Yousefieh field, a few kilometres to the east, was brought on-stream in April 2010. Gulfsands had an intensive programme of exploration and in the first half of 2011 Block 26 was producing 24 MMbbl/d. However, by October 2011 this had dropped to about 6 MMbbl/d on the instructions of the Syrian Oil Ministry, due to reduced availability of crude storage capacity within the country.

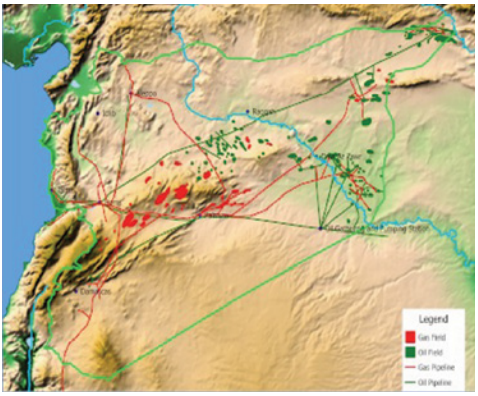
Map 8.42 **Syria's geological framework**



Map 8.43 **N-S geological cross section of the Northeastern Mediterranean area (59)**



Map 8.44 **Syrian oil and gas map**



Romania

Sustained growth in the consumption of natural gas, petroleum, and petrochemical products is one of the major drivers of growth for oil and gas companies in Romania. Companies operating in the industry can benefit from this opportunity through investing and participating in the oil and gas trade, undertaking oil and gas pipelines and contracts and expanding their production capacity. The Romanian oil and gas upstream market is moderately consolidated. Some of the key players in this market include OMV Petrom SA, SGS SA, Exxon Mobil Corporation, Romgaz SA, and Foraj Sonde SA Videle. A number of recent legislative changes including the Offshore Petroleum Agreements Law 256/2018, and amended Emergency Ordinances (OUGs) 114/2018, 19/2019 and 1/2020, are seen as restrictive to the industry - notably a gas sale price cap of RON 68 (US$16)/MWh for domestic household consumers, a flat 2% tax based on company turnover and the Offshore Act's obligation to sell half of Black Sea gas to the local market (16,64).

Romania is a country located at the crossroads of Central, Eastern, and Southeastern Europe. It borders on the Black Sea to the southeast, Bulgaria to the south, Ukraine to the north, Hungary to the west, Serbia to the southwest, and Moldova to the east (4). The geology of Romania is structurally complex, with evidence of past crustal movements and the incorporation of different blocks or platforms to the edge of Europe, and the recent mountain building of the Carpathian Mountains. Romania has oil and gas in Moesian and Scythian platform cover, coal in Carboniferous, Jurassic, Miocene and Pliocene basins and Miocene salt deposits in the Transylvanian Depression and Carpathians (Popescu, 1995). Several petroleum systems have been identified in Romania (65). Most hydrocarbons were expelled or re-migrated into the reservoirs after the Late Styrian orogenic phase, 12-14 Ma years ago. Hydrocarbons mostly accumulated in fields during the Late Sarmatian-Pliocene interval, after the Moldavian orogenic phase. Most gas in the Sarmatian-Pliocene reservoirs of the post-tectonic basins is biogenic. Evaluation of exploration history and fractal distribution laws of discovered hydrocarbons suggest future discoveries in the five major onshore petroleum systems of 15 MMt of crude oil. Undiscovered resources in the entire Carpathian–Balkanian Basin Province are estimated, at the mean, to be 2,076 Bcfg, 1,013 MMbbl of oil, and 116 MMbbl of natural gas liquids (Total Petroleum Systems of the Carpathian–Balkanian Basin Province of Romania and Bulgaria (Pawlewicz M. 2007) (66).

Licensing update on Romania

In July 2019, the National Agency for Mineral Resources (NAMR) launched an auction (Round XI) for 28 exploration blocks, 22 onshore in the Carpathians, Moesian Platform and Transylvanian Basin, and 6 offshore in the Black Sea (17) (Map 8.45). The onshore total size covers 20,370 sq km and the offshore 5,274 sq km with block sizes ranging from 653 to 1,098 sq km for the onshore and from 802 to 915 sq km for the offshore.
The round was deferred until 2021 once the disputed elements of the 2018 Offshore Law have been resolved, most notably the requirement to sell 50% of gas produced offshore to the domestic market.

Near-term development

Lebada Fields

In 2018, OMV Petrom drilled its first multilateral well LV07 on Lebada West in the Black Sea. In September 2020 (100% equity) it completed three shallow water wells on Lebada East Field. The wells were targeting Cretaceous oil and Eocene gas, with maximum drilled total depth of 2,000m. All three wells were put on production by Q1 2020. OMV Petrom produces some 25,000 bbloe/d from the Istria fields - Lebada West, Lebada East, Sinoe, Pescarus, and Delta (67) (Map 8.46).

Caragele Deep

First gas from the deep structure, Caragele Deep, came at the end of January 2020 with the development of two mid-depth reservoir wells. Further, Romgaz commenced gas production in the Rosetti 77 well producing 1,500 bbloe/d (16). Alongside this, two new development wells for the medium reservoir were also brought on stream at 1,000 bbloe/d. Romgaz drilled a further 9 wells on Caragele Deep during 2019/20, five of which are within the known margins of the field, and four in order to assess the extent of the field. Caragele is located on the RG 06 Muntenia Nord Est concession on the Moesian platform in south-eastern Romania. The structural complex extends over 35km in the NE of Muntenia Nord Est and has multiple reservoirs between 1,500 - 5,000m.

In 2004 the Caragele 4 NFW was drilled to a TD of approximately 2,150m, discovering gas. The Damianca 55 exploration well was drilled during 2015 targeting dual objectives in the Badenian (Middle Miocene) and Jurassic with a PTD of 4,770m. A 120m Jurassic carbonate interval below 4,000m was tested in both the Damianca 55 and the Rosetti 77 exploration wells, subsequently estimated to contain 150-170 MMbboe contingent resources, with expected production rates between 1,400 - 2,200 bbloe/d.

Neptun Deep Project

The discussions during 2019 on the amendment of the offshore law in parliament in order to facilitate unlocking the gas projects in the Black Sea pushed ExxonMobil to announce possible withdrawal from their 50% holding in the Neptune offshore block while Romgaz considered the opportunity to take a 15-20% stake. The reason was the ordinance (OUG) 114 that capped the gas price for producers. OMV did not intend to withdraw from Neptune Deep in the Black Sea, but deferred the Final Investment Decision (FID) for the Neptun Deep project to develop the Domino and Pelican South fields in the Black Sea beyond 2020. The Neptun Deep Project has contingent resources of 1.5 to 3.0 Tcfg in the Domino & Pelican South fields (17) (Map 8.47).

Midia Gas Development Project

Black Sea Oil & Gas has developed the Midia Gas Development Project (MGD) and in September 2020, commenced construction on the 126km pipeline from the MGD's Ana and Doina fields to shore at Vadu, with first gas targeted for Q4 2021. MGD's Ana and Doina gas fields are located on the XV Midia Shallow license in the Black Sea, with estimated 2P gas reserves of 255 and 320 Bcfg extending the MGD to include further satellite fields. Sterling discovered Doina in 2005 and Ana in 2008, both located within Dacian-Romanian (Pliocene) sands (17) (Map 8.47).

E X-30 Trident

LUKoil should drill 3 wells in 2020 in the Trident EX-30 block in the Black Sea, where a gas discovery of 30 Bcm was previously reported (Map 8.47). E X-30 Trident covers approximately 1,000 sq km and was awarded on 4 November 2011 as part of the 10th Bid Round. Lukoil shot 2,000 sq km over the acreage in 2012 and has also drilled two unsuccessful Pontian NFWs on the block, Daria 1 (2015, PTD 3,900m) and Trinity 1X (2019, PTD 3,250m) (16). Further plans to drill the A1 and A2 prospects have apparently been shelved, likely as a result of Trinity's failure.

Former partner PanAtlantic withdrew in 2018, with its previous 18% stake reassigned pro-rata to the remaining partners. A three-and-a-half-year extension of the block was approved on 15 May 2018, until 5 November 2021, to allow full evaluation of the Lira 1 discovery on the SW of the block and further exploration.

E X-30 Trident participants are Lukoil Overseas Atash BV (87.8% + Op) and SNGN Romgaz SA (12.2%). The E X-30 Trident partners are preparing a resource development plan for the Lira discovery, expected to be completed by December 2020. Lira 1 (2015, 2,700m TD) was drilled in 780m WD and encountered 46m gross gas pay, assumed to be in the targeted Miocene Pontian sandstone. Lukoil has since announced 1.13 Tcfg estimated contingent resources. Lira lies 55km NE of the Midia Gas Development (MGD), with estimated 2P reserves of 255 Bcfg in the Ana and Doina fields, from which Black Sea Oil & Gas (BSOG) plans to commence gas production in Q4 2021; and 60-75km N of ExxonMobil-OMV Petrom discoveries Pelican South and Domino on XIX Neptune Deep block, which have combined resources in the range of 2.2 to 3.9 Tcfg.

Both developments have been hampered by legislation, specifically OUG 114/2018, which includes price caps and a 2% tax on company turnover, and the 2019 Offshore Act, which requires half of Black Sea gas to be sold to the local market. The government has sought to overturn OUG 114 but this remains in limbo following a vote of no confidence in February 2020, and no change is expected until after the general election scheduled for the end of2020. BSOG is moving ahead with MGD but ExxonMobil is set to exit Neptune Deep and OMV Petrom has delayed a final investment decision into 2021.

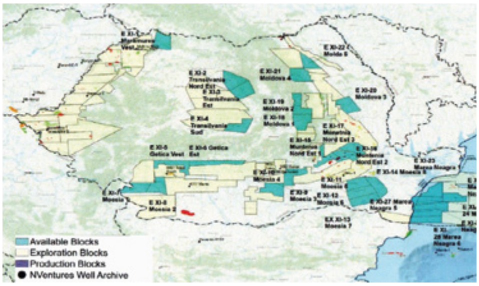
Other blocks

In 2019, OMV Petrom announced a gas discovery in the Oltenia region in the proximity of Totea gas field, which will compensate for the decline in production of the field.

Long-term developments: gas and oil resource estimates and reserves

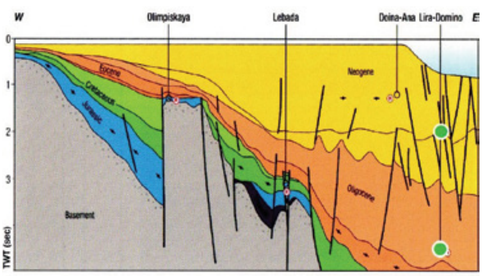
Romania is the largest natural gas producer in Central and Eastern Europe and the increased Natural Gas demand is expected to propel the Romanian market forward drastically. Most of Romania's output today is from the onshore fields. Romania is relatively self-sufficient in natural gas, with imports averaging around 10-15% over the past few years. It produces about 90% of its annual gas demand of around 11 Bcmg per year, with the remainder imported from Russia. According to BP, in 2019, approx. 9.7 Bcmg was produced locally and the remaining quantity of 1.4 Bcmg was imported to cover domestic consumption. Obviously, the Black Sea resources have the potential to turn the country into a net exporter. Romania has a century of experience in natural gas production. New production from the Black Sea would eliminate the need for imports from Russia and could make Romania an exporter of gas to the wider southeast European region. In addition, Romania is developing a new export route, the BRUA corridor, which would take Romanian offshore gas via Hungary to Slovakia and potentially to the Baumgarten gas hub in Austria. Romania's proven crude and condensate reserves are expected to deplete over the next 20 years at a speed depending on the rate of extraction. Having the largest number of active wells in Europe and oil production coming from Black Sea platforms, its 400 reservoirs, most of them small and fragmented, will require the use of modern and specialized technologies, thus providing conditions for new synergies and strong international investment.

Map 8.45 **Licensing recent history of Romania**



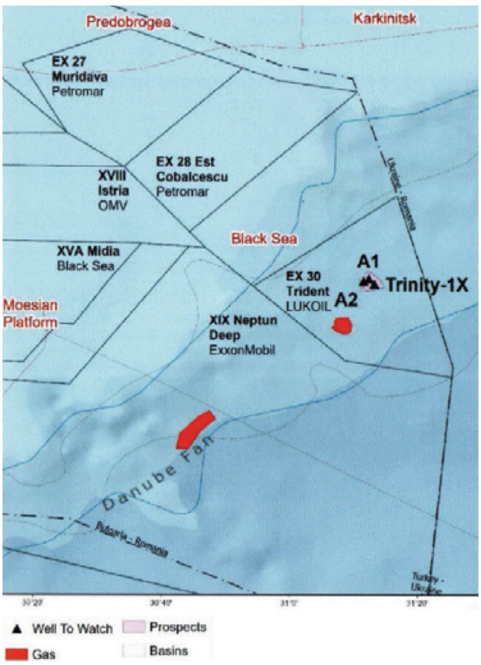
Source: Courtesy NP Ventures (17)

Map 8.46 **Lembada Field**



Source: Courtesy NVentures 2020 (67)

Map 8.47 **EX-30 Trident block location**



Source: Courtesy NVentures 2020 (17)

Bulgaria

The geology of Bulgaria consists of two major structural features. The Rhodope Massif in southern Bulgaria is made up of Archean, Proterozoic and Cambrian rocks and is a sub-province of the Thracian-Anatolian polymetallic province. Faulted basins are filled with Cenozoic sediments and volcanic rocks. The Moesian Platform to the north extends into Romania and has Paleozoic rocks covered by rocks from the Mesozoic and by thick Danube River valley Quaternary sediments. In places, the Moesian Platform has small oil and gas fields.

Undiscovered resources in the Carpathian–Balkanian Basin Province comprising both Bulgaria and Romania onshore are estimated, at the mean, to be 2,1 Tcfg, 1 Tbbl of oil and 116 MMbbl of natural gas liquids (67). Although Bulgaria is not very rich in fossil fuels such as coal, oil and gas, it has a well-developed energy sector which is of crucial importance for the Balkans. Gas is currently a small component of the country's energy mix. Bulgaria's natural gas domestic market is around 3.5 Bcmg per year. However, it is primarily used by the industrial sector. Bulgaria is believed to have extensive natural gas resources exploitable with hydraulic fracturing but this is banned under EU legislation.

Licensing update in Bulgaria

Two important projects marked 2019 and early 2020 (4) (Fig 48). Exploration work commenced in the onshore block **1-25 Vratsa West** by SPM Bulgaria LLC in Q2 2019, with 2D and 3D seismic acquisition planned for the second year of the concession and a well in the fourth or fifth year. The block, at the eastern border of Bulgaria, covers 4,886 sq km over Vidin, Vratsa and Montana Counties on the southern edge of the Moesian Platform, NW Bulgaria. The block was relinquished by Direct Petroleum in 2010. The acreage contains over 70 previous exploration wells drilled before the 90s by the state agency Committee of Geology & Mineral Resources (CGMR). Several of the wells reached the Middle Triassic (drilled depth max 5,100m) and hydrocarbon shows have been observed in several exploration wells drilled into Cretaceous-Permian horizons from the 1960s-1980s. A public tender was launched on 30 March 2020 for the offshore **Block 1-26** Tervel (in 2013 and 2015 offered as **Block 1-22** Theres), with bidding closing on 1st of September 2020 (16). The 4,032 sq km block lies in 1,900-2,100m of water depths in the Black Sea (17) (Fig 49).

The block is surrounded:

- to the west by **1-14 Khan Kubrat** where Shell together with Woodside Energy (30%) and Repsol (20%) recently drilled the Khan Kubrat-1 NFW (New Field Wildcat) P&A dry well with shows,

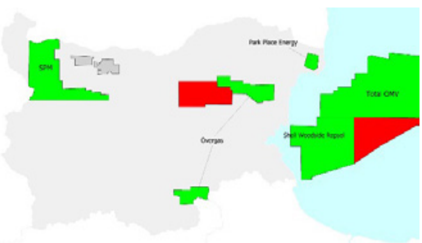
- to the north by **1-21 Han Asparuh** where Total - OMV - Repsol acquired 5,500 sq. km 3D seismic. **1-21 Han Asparuh** contains also the Polshkov 1 Oligocene oil discovery (2016), the Rubin 1 (2017) and the **Melnik 1** (2018) unsuccessful NFWs and,
- to the southwest by the Turkish maritime boundary (17) (Map 8.50).

Melnik-1 is the third deep water well on the 1-21 Han Aspurah block by Total. **Rubin-1** was drilled in 2018 targeting Cenozoic clastic plays overlying a Mesozoic carbonate faulted block. It was a follow up to the oil discovery of Polshkov-1 well to the southwest.

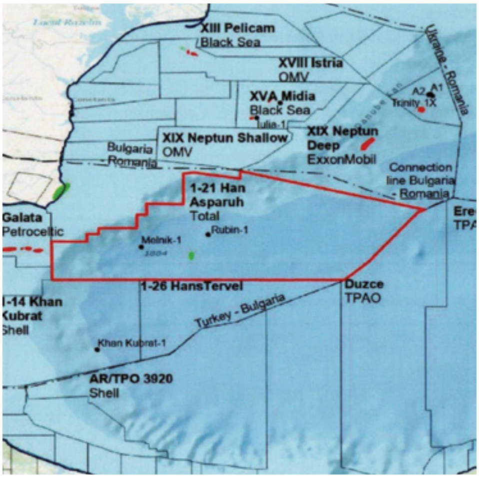
Long-term developments: gas and pipelines

Most of Bulgaria's energy is produced from fossil fuels, almost twice that produced from hydropower or nuclear energy, which represent 36% of total produced power (16). Oil and gas consumption will increase due to a strong economy and population growth, as the country's infrastructure continues to rely heavily on petroleum-based products. The market players undertook several investment plans in response to the increasing demand for oil and gas products, pipeline projects and associated contracts. The country's strategic geographical location makes it a major hub for transit and distribution of oil and gas from Russia to Western Europe and other Balkan states. Bulgaria's gas transmission network has a maximum throughput capacity of 7.5 Bcmg per year. As of January 1, 2020 Bulgaria, has started importing Russian gas through the Turkish Stream pipeline, via Turkey, avoiding expensive transit through Ukraine and Romania.

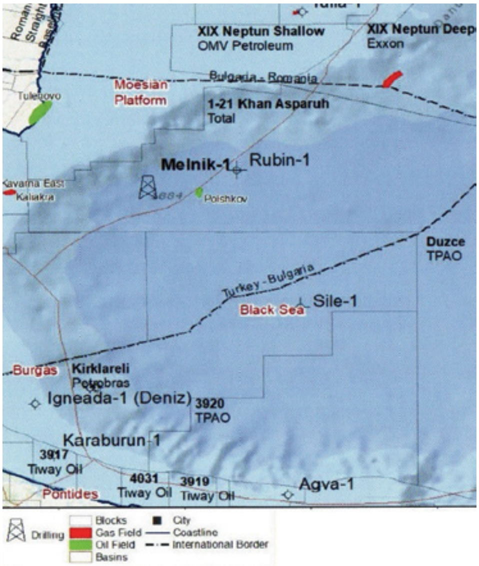
Map 8.48 **Concessions map of Bulgaria (4)**



Map 8.49 **Location** of Block 1-26 Tervel south of Block 1-21 Han Asparuh and west of 1-14 Khan Kubrat (17)



Map 8.50 **Location** of Block 1-21 Khan Asparuh north of the Turkish border (17)



Turkey

Turkey has a strong interest in oil and gas exploration and production having established a state oil company as early as 1954. Known as Türkiye Petrolleri Anonim Ortaklığı (TPAO), it is now active in the entire oil and gas chain as it is engaged in hydrocarbon exploration, drilling, production, refinery and marketing activities on behalf of the Turkish Republic operating under Law 6327 of 1954.

The establishment of industry giants like PETKİM, TÜPRAŞ, and PETROL OFİSİ are amongst the many milestones TPAO has achieved in the Turkish petroleum industry. TPAO continued exploration, production, refining, marketing and transportation activities until 1983 as an integrated oil company. TPAO has been acting as a state-owned exploration and production oil company since the introduction of a legal framework in 1983 and other more recent regulatory changes. TPAO's primary goal is to help reduce Turkey's oil and gas imports by exploiting indigenous hydrocarbon resources. Turkey has a strong drive to boost its proven reserves of oil and gas and increase production, because it is highly dependent on imports. In 2019 Turkey consumed just over a million barrels of oil per day and 43.2 billion cubic meters of gas(Bcmg) (BP Statistical Review, 2020). Of this amount, Turkey imported 31,1 MMtoe and 45,21 Bcmg, which clearly shows its high hydrocarbon import dependence. Exploration gained ground during 2015-2018.

The country's exploration policy changed in 2017, when Ankara commissioned three drilling ships along with two seismic vessels in the Black Sea and the Eastern Mediterranean. Turkey has the longest coastline in the Black Sea and controls the largest offshore portion of the Exclusive Economic Zone there. Since 2004 the TPAO has sponsored over 50,000 km of 2D data and 14,000 sq km of 3D data as either operator or joint venture partner. In 2013 TPAO mobilized the Leiv Eiriksson drillship after OMV and ExxonMobil discovered gas at Domino in the Bulgarian sector. Only now, with the state-owned drillship Fatih, has TPAO been able to venture beyond 2,000m water depth and test deeper Miocene targets.

TPAO has stated that it believes without doubt that the Turkish sector of the Black Sea can hold up to 53 Tcf, leaving Ukraine, Georgia, Romania and Bulgaria behind. Turkey is located in an area where the Eurasian and African plates collide. Due to this collision, not only European and African plates amalgamated, but also small continental fragments (68) (Map 8.51). Of these basins, the SE Anatolian basin, Thrace Basin, Adana Basin, and the Black Sea Basin have hydrocarbon (HC) production. The Thrace and Black Sea Basins present significant geological interest. The Thrace Basin is a SE-NW trending trough controlled by fault systems, and the sediment fill reaches about 9000 m (68). Deltaic sediments of Late Eocene-Oligocene have mainly oil, some Middle to Late Eocene sediments have both oil and gas, and some Early to Middle Eocene sediments have gas potential. It is difficult to determine if the basin has oil and/or gas generating potential, because the immature part has high organic matter but the mature part has very poor organic content. In terms of gas, the source of the thermogenic gas is Early to Middle Eocene, since this formation has overmature organic matter and organic matter capable of generating gas (69). The source of southern gas is probably Late Eocene-Oligocene. Hydrocarbon shows have been known in northern Turkey onshore and offshore for more than 100 years. A total of about 40 wells have been drilled to date; six wells have gas shows. Shell chief executive Peter Voser has indicated that his company, now conducting a shale gas exploration programme in the south-east of the country, is assessing oil exploration and production opportunities in the Black Sea with TPAO; media sources indicate that the award of ultra-deep-water acreage to Shell is imminent.

Licensing update Turkey

<u>Sea of Marmara and Thrace</u>

On October 2020 Valeura sold its Thrace Basin shallow conventional gas production business to TBNG Ltd for US$15.5m plus royalty payments of up to US$2.5m (17) (Map 8.52). Valeura retains its deep tight gas play interest in 20 Tcfg unrisked, meaning that prospective resource deep, tight gas play in the Thrace Basin will be unaffected by this transaction. In early June 2019, the General Directorate of Petroleum Affairs (GDPA) awarded Turkish Petroleum Corp (TPAO) and BOTAS Petroleum Pipeline Corp a joint exploration license for the offshore area F20-d3 (84.42 sq km) in the Sea of Marmara. The acreage contains the shut-in Marmara North gas field, which has been used for gas storage in the past. TPAO operates the acreage with a 50% interest, with BOTAS holding the remaining 50%. On June 2019, the General Directorate of Petroleum Affairs (GDPA) awarded Turkish Petroleum Corp (TPAO) seven new exclusive offshore exploration licenses in the northern and central part of the Sea of Marmara (F19-c3, c4, F19-d3, F20-c3, c4, F20-d4, F21-d4, G20-c and G20-d). The offshore licenses cover a total of 1,300 sq km and will be valid for eight years. Seven of the blocks have been previously licensed but they remain largely unexplored with only a few wells drilled. Some of the licences fall within a zone for which TPAO acquired a 3D seismic survey in 2016, with its "Barbaros Hayreddin Pasa" vessel (formerly the "Polarcus Samur"). The company is currently acquiring another survey in the Sea of Marmara with the "MTA Oruc Reis" vessel.

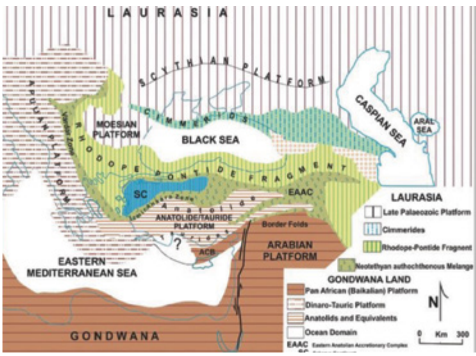
In mid-February 2019, the General Directorate of Petroleum Affairs (GDPA) rejected Turkish Petroleum Corp's (TPAO) exploration licence application for onshore area F19-b1, b4. TPAO had submitted the application on 19 December 2017. The GDPA also rejected three rival applications, which had been submitted by Tekirdag Enerji, Arti Iletisim Telekomunikasyon ve Dis Ticaret Ltd and Traoil Dogal Enerji Kaynaklari Arastirma ve Uretim San Tic AS. Block F19-b1, b4 (240.11 sq km) is located in the NW Turkish province of Tekirdag (District I), just North of TPAO's existing F19-c1, c2, c4 exploration licence. It has been part of various licences in the past and contains the Velimese West gas discovery (2006). The block lies within the Thrace Basin, which has received a lot of attention recently, following Valeura and Statoil's successful Yamalik 1 NFW. Over four production tests within the Eocene Kesan formation, the well tested an aggregate 24-hour rate of around 2.9 MMcfg/d, thereby validating the joint venture's basin-centred gas play concept. Area F19-b1, b4 lies along the northern edge of this play fairway. In February 2020, Yakamoz-1 S/T well in the Ortakoy block (71) (Map 8.53) was drilled in a thrusted 4-way dip closure and encountered significant gas shows associated with fractures in the Eocene and basal Miocene. Condor Petroleum have reprocessed 2D seismic data and mapped updip potential at multiple levels in the Miocene to Eocene, which will be targeted by this planned sidetrack which will also deepen into the subthrust. Any commercial gas discovery would be tied in the 2 km to the existing infrastructure for a cost of US$1 million.

Black Sea

Turkey controls the largest Black Sea acreage and TPAO believes that the sector holds reserves of 10 Bb of oil and 53 Tcf of gas. Earlier, the company had announced that it would invest US$4 billion in the Black Sea over the period 2011–13 while the Ministry had announced it was aiming for commercial production in either 2015 or 2016 (72). Although there is plenty of available acreage, so far this investment has yielded little in the way of commercial reserves, and concerns that the Black Sea's prospectivity may be overrated have for many years affected investment levels. At present TPAO has all the deep and ultra-deepwater licences, and following the exit of Petrobras and ExxonMobil, no international players are involved. (16). In August 2020, Turkey announced its biggest discovery of natural gas in the Black Sea's Tuna-1 (TD. 4,775 m) 60 km from the Domino gas discovery in the Romanian sector of the Black Sea. According to TPAO, the well Tuna-1, which was drilled at 2,115 meters of water depth reaching a final total depth of 4,525 metres, encountered more than 100 m of natural gas-bearing reservoir in Pliocene and Miocene sands. The well was drilled on the Sakarya licence (Blocks C26, C27, D26 and D27) (73) (Map 8.54). The block is 7,000 sq km. Tuna-1 has been deepened and discovered a second major reservoir at Sakarya, an additional 30m of gas in Mio-Pliocene sands. Reported volumes of lean gas have increased by 85 Bcmg (3 Tcfg) to a total of 405 Bcmg (14.3 Tcfg) in place. Earlier reports of the shallower reservoir claimed >130m gas column also in Mio-Pliocene sandstones, probably trapped stratigraphically in a major fan system, 60km from the Domino gas discovery in the Romanian sector of the Black Sea. Sakarya is the largest gas discovery in the Black Sea and potentially makes Turkey self-sufficient in gas for decades.

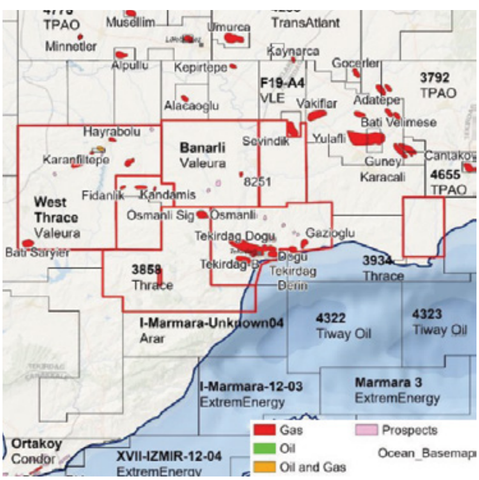
TPAO will appraise via blockwide 3D seismic data, two back-to-back appraisal wells, and flow testing ahead of first gas production planned for 2023. Turkey has been carrying out the drilling with the Fatih drillship which joined the Turkish Petroleum Corporation (TPAO) inventory in 2017. The newly discovered natural gas was found during the ninth round of deep drilling.

Map 8.51 **Tectonic map showing the continental fragments involved in the evolution of Turkey** as proposed by Şengör and Yilmaz (1981). In this scheme various belts have been recognized and described which correspond to either a continental block or a suture zone that is amalgamated as a result of the Neo-Tethyan collision and which is marked by an ophiolitic suite of rocks (redrawn from Şengör and Yilmaz, 1981)



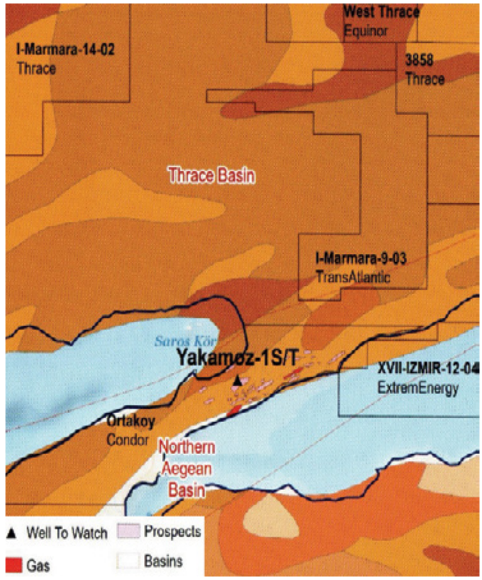
Source: Derman, Ahmet Sami, 2014, Petroleum systems of Turkish Basins, in L. Marlow, C. Kendall, and L. Yose, eds., Petroleum systems of the Tethyan region: AAPG Memoir 106, p. 469-504 (68)

Map 8.52 **Map of blocks in the Thrace Basin**



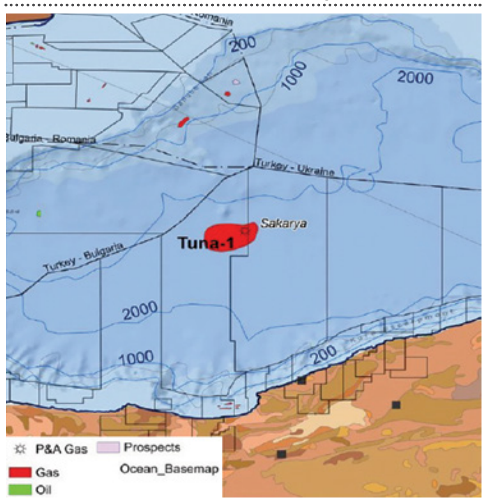
Source: NVentures, 2020 (17)

Map 8.53 **Yakamoz-1S/T well in the Ortakoy block, southern border of the Thrace Basin (71)**



Source: NVentures, 2020 (17)

Map 8.54 **Location of the Tuna-1 gas well in the western Black Sea, offshore Turkey (73)**



Georgia

In terms of geological structure, almost the entire intermountain depressed line of the country and its offshore extension within the Black Sea have oil and gas-bearing potential. The territory of Georgia may be divided into 3 large tectonic units which extend sub-latitudinally (74) (Map 8.55).

Mountainous structures of the Greater and the Lesser Caucasus of overthrust-folding and folded-block type are located to the north and to the south. A rather large depressed line is located among them. It expands westwards and enters the Black Sea basin where the Rioni molasse troughs extend. In the South Caucasus oil and gas deposits are mainly located within intermontane lowlands surrounded by the Caucassus mountains ranges from the north and the Lesser Caucasus mountains ranges from the South. Georgia's estimated reserves of oil as of 2018 are 4,81 Bto, and possible reserves are 21,52 Bto. Estimated gas reserves are 4,59 Bcm and possible 5,87 Bcm. Georgia is a net importer of oil and natural gas (17).
The main suppliers of Georgia are Azerbaijan and other littoral countries of the Caspian Sea. Georgia has 2.16 MMt of proven oil reserves (category 1P) as of January 1, 2016, but only a marginal amount has been exploited. Domestic natural gas reserves are estimated at 1.9 Bcmg (category 1P) as of January 1, 2016; however, little natural gas is being produced primarily due to retracted production activities. Most of the country's demand for oil and gas products is met through imports.

Licensing update on Georgia

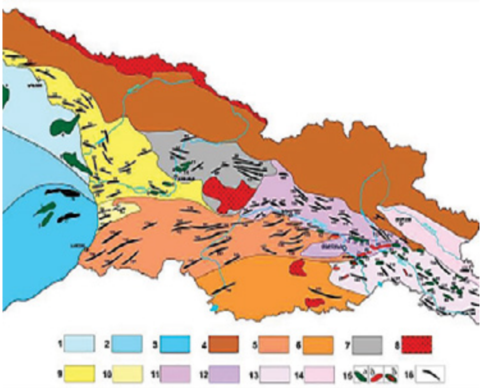
In 2019, Georgian authorities offered 7 onshore blocks in the Kura and Rioni basins. In January 2020, 2 offshore blocks were available for biding in the Black Sea with deadline for submission the 20th of April 2020 (16) (Map 8.56). Block Energy had an oil discovery in the near horizontal section in deviated sidetracked appraisal well WR-38Z in the Eocene reservoir of the West Rustavi oilfield in the Kura basin.

According to the operations update, the production test has shown high gas content with high constant water cut. A similar sidetrack of the producing well WR-51Z incorporated results of the recent 3D seismic survey.

Short and mid-term developments

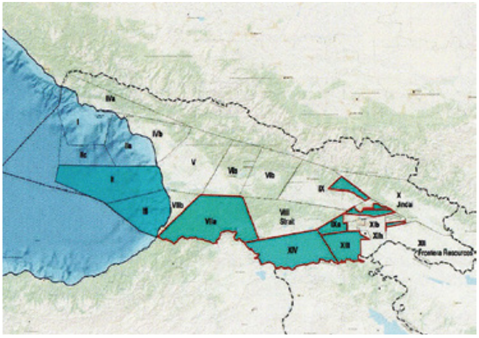
Georgia's Black Sea oil terminals will be expanded in order to ensure additional throughput and large tonnage tanker services. The Oil and gas exploration would increase under this scheme.

Map 8.55 **Blac k Sea oil terminals**



Shatsky Rise 2-East Black Sea recess; 3-Marine part of Guria depression; 4-Caucasus Mountains; 5-Adjara-Trialeti folded zone; 6 -Artvin-Bolnisi uplift; 7-Dzirula-Imereti uplift; 8 – Shows on the surface of the foundation; 9-Rioni trough; 10-Onshore part of Guria depression; 11-Zemo Mtkvari-Kartli trough; 12-Tbilisi-Sagarejo uplift; 13-Outer Kakheti trough; 14-Alazani trough; 15 -Structures on which prospective resources are estimated (Map 8.## 1-49, A- Oil, B-Gas, C-Gas-Oil); 16 – Structures without estimation (## 50-160) (74).

Map 8.56 **Georgia's maritime and land concessions areas in the western Black Sea (17)**



References

(1) DLouly J., 2021, API considers backing a government-imposed carbon pricing program. World Oil, 3, February 2021.

(2) IEA, Gas 2018, Analysis and forecasts to 2024, published 2019.

(3) Elliot P., 2021, Oil & Gas Exploration: The Tide Turns, GeoExpro, Vol. 18, No. 1 – 2021.

(4) Balkans and Black Sea Annual Report, 2019.

(5) Croatian Hydrocarbon Agency, Annual Report 2020.

(6) Oil and Gas Exploration Success in the Eastern European Pannonian Basin, 2020, Geoexpro, Vol. 17, No. 2, 2020.

(7) Enverus Asset Evaluator, Adriatic Sea, November 2020.

(8) Middle East Petroleum and Economic Publications, 2019, Upstream Oil and Gas, Petroleum Economist, March 2019.

(9) Bassias Y., 2019, The search for hydrocarbons- A roadmap for development, in «Greece-Cyprus in the New Energy Era», IENE Publications (in Greek), Athens, 2019, p. 118-125.

(10) Bassias Y., 2020, Beyond the Quest for Hydrocarbons in Greece, in: Financing the Energy Transition: Status and Future Challenges, Hellenic Energy Regulation Institute, Eurasia Publications, 2020, p. 87-104.

(11) Mark Pawlewicz 2007. Total Petroleum Systems of the Carpathian–Balkanian Basin Province of Romania and Bulgaria, Bulletin 2204–F, U.S. Geological Survey, Reston, Virginia: 2007.

(12) Eastern Balkans and Western Black Sea, Enverus Asset Evaluator, November 2020.

(13) Annual Report 2020, Croatian Hydrocarbon Agency

(14) Annual Report 2019, Croatian Regulatory Authority.

(15) Annual Report 2018, Croatian Regulatory Authority.

(16) Enverus International Scout Articles, October 2020.

(17) NVentures Mediterranean and Europe Activity Updates, February 2020.

(18) 18 Federal Ministry of Energy, Mining & Industry (FMERI, 2020) https://fmeri.gov.ba and http://www.fbihvlada.gov.ba

(19) Enverus International Scout Articles, October 2020.

(20) NVentures Mediterranean and Europe Activity Updates, February 2020.

(21) Čokorilo, Voijin; Lilić, Nikola; Purga, Jaanus; Milisavljević, Vladimir (2009). "Oil shale potential in Serbia" (PDF). Oil Shale. A Scientific-Technical Journal. Estonian Academy Publishers. 26 (4): 451–462. doi:10.3176/oil.2009.4.02. ISSN 0208-189X. Retrieved 2010-09-12.

(22) Oil and Gas Journal, January 4, 2017.

(23) JELENKOVIĆ R.*, KOSTIĆ A, DRAGANA ŽIVOTIĆ D. & ERCEGOVAC M., 2008, Mineral resources of Serbia, GEOLOGICA CARPATHICA, AUGUST 2008, 59, 4, 345—361

(24) Knutson, Carroll F.; Dana, George F.; Solti, Gabor; Hutton, Adrian C.; Russell, Paul L.; Macauley, George; Piper, Edwin M. (1987). "Developments in Oil Shale in 1986". AAPG Bulletin. American Association of Petroleum Geologists. 71 (10B): 374–383. doi:10.1306/703c81aa-1707-11d7-8645000102c1865d.

(25) "Oil shale reserve-holders look to international investment". Platts. Alexander's Gas & Oil Connections. 2009-06-09. Retrieved 2010-09-26.

(26) "FM: Estonia supports Serbia's EU integration". B92. 2010-03-10. Retrieved 2010-09-26.

(27) U.S. Department of the Interior, Open File Report 97-470

(28) http://www.mha.gov.me

(29) http://www.akbn.gov.al/category/hidrokarburet/

(30) http://www.energjia.gov.al/

(31) Hydrocarbon Exploration in Greece - The role of HHRM - An interdisciplinary approach to the new hydrocarbon exploration in Greece and the Southeast Mediterranean Sea and their contribution to economic recovery, 2020,

https://www.greekhydrocarbons.gr/news_files/ hhrm_book_2020_eng.pdf

(32) Bassias Y. (2020). The role of hydrocarbons for the Greek economy. Foreign Affairs (Greek edition April 2020), 63, p.109-130.

(33) Hydrocarbons in the SE Mediterranean - Assembling the Tiles. EPOCH 2020 of Sustainability Conference, October, 5-6, 2020.

(34) Hydrocarbon in Greece – New research orientations,

https://www.greekhydrocarbons.gr/news_files/ydrogonanthrakes_Ellada_nees_prosegiseis_stin_erevna.pdf

(35) Mascle, J., Mary, F., Praeg, D., Brosolo, L., Camera, L., Ceramicola, S., & Dupré, S. (2014). Distribution and geological control of mud volcanoes and other fluid/free gas seepage features in the Mediterranean Sea and nearby Gulf of Cadiz. Geo-Marine Letters, 34(2-3), 89-110.

(36) Perissoratis, C., Ioakim, C., Alexandri, S., Woodside, J., Nomikou, P., Dählmann, A. & Lykousis, V. (2011). Thessaloniki mud volcano, the shallowest gas hydrate-bearing mud volcano in the Anaximander Mountains, Eastern Mediterranean. Journal of Geological Research, 2011.

(37) Tayber Z., Meilijson A., Ben-Avraham Z., Makovsky Y. (2020). Methane Hydrate Stability and Potential Resource in the Levant Basin, Southeastern Mediterranean Sea. Geosciences 2019, 9(7), 306.

(38) Libya - The Next Chapter, Geoexpro, Vol. 8, No. 6 – 2012.

(39) Exploration Update – Libya, Geoexpro and Drillinginfo, First Offshore NFW of 2017, Vol. 14, No. 3 – 2017.

(40) http://jointoilblock-zarat.com/index.php/dataroom/

(41) https://www.offshore-technology.com/

(42) http://ganope.com/index.php/multiclient/offshore/bidround-2019-final/

(43) Simon Baer, Øystein Lie, Matthew Pyett, Chris Davies, Rune Sakariassen; PGS & Aymen El Morshedy; EGAS (Egyptian Natural Gas Holding Company) GeoExpro, Vol. 13, No. 1 – 2016

(44) Hot Spot: Ten gas discoveries across Egypt, Israel & Cyrprus define the East Mediterranean Hydrocarbon hotspot, GeoExpro, Vol. 15, No. 3 – 2018

(45) Major oil discovery announced in the prolific Abu Gharadig Basin of Egypt's Western Desert, GeoExPro, Vol. 16, No. 1 – 2019.

(46) Several promising play types can be identified on new pre-stack depth migrated seismic, GeoExpro, Vol. 14, No. 5 – 2017

(47) Hot Spot: Ten gas discoveries across Egypt, Israel & Cyrprus define the East Mediterranean Hydrocarbon hotspot, GeoExpro, Vol. 15, No. 3 – 2018

(48) www.chc.

(49) Natural Resources Administration of the Ministry (dinal@energy.gov.il) and www.energy-sea.gov.il.

(50) Israel petroleum systems - AAPG Wiki

(51) *Exploration Update: Significant Gas Discovery Offshore Israel, Geoexpro, June, 2019*

(52) *GeoExpro March 2019, Lebanon's Second Offshore Licensing Round is set to open.*

(53) *Soledad Velasco, "Lebanon. The New Levantine Exploration Opportunity", GeoExpro, Vol. 12, No. 6 -2016*

(54) *Block Delineation Decree - Rev 5 - 29-09-2015, PR 03 - Annex 1', available on the Lebanese Petroleum Authority's website.*

(55) *GeoExpro March 2019, Lebanon's Second Offshore Licensing Round is set to open.*

(56) *Total strengthens its position in the Mediterranean region by entering two exploration blocks offshore Lebanon', 9 February 2018, at https://www.total.com/en/media/news/press-releases/*

(57) *Total E&P Liban Announces Results of Byblos Exploration Well 16/1 Drilled on Block 4, 27 April 2020, at https://www.total.com/en/media/news/press-releases/*

(58) *Eric Barrier, Louai Machhour, Marc Blaizot, 2014,AAPG Special Volumes, Memoir 106: Petroleum Systems of the Tethyan Region, Chapter 11: Petroleum Systems of Syria, 2014, Pages 335-378.*

(59) *Chamot-Rooke N., Rangin, C. Le Pichon, X. & Dotmed Working Group, 2005. DOTMED: Deep Offshore Tectonics of the Mediterranean: a synthesis of deep marine data in Eastern Mediterranean. Mémoire Société géologique de France and American Association of Petroleum Geologists 177. Paris: Société géologique de France.*

(60) *Skiple, C., Anderson, E., Fürstenau, J. 2012. Seismic interpretation and attribute analysis of the Herodotus and the Levantine Basin, offshore Cyprus and Lebanon. Petroleum Geoscience, 18. 433-442. DOI: 10.1144/petgeo2011-072.*

(61) *Geo Expro, Vol. 9, No. 1 – 2012.*

(62) *Geo Expro, Vol. 11, No. 1 .*

(63) *(BP Statistical Review of World Energy (2003) : Oil and Gas Journal , Dec. 2, 2013).*

(64) *NAMR Annual Report, 2020*

(65) *Popescu B. 1995. Romania's petroleum systems and their remaining potential, November 1995, Petroleum Geoscience vol 1(4):337-350*

(66) *Mark Pawlewicz 2007. Total Petroleum Systems of the Carpathian–Balkanian Basin Province of Romania and Bulgaria, Bulletin 2204–F, U.S. Geological Survey, Reston, Virginia: 2007.*

(67) *Bulgarian Ministry of Energy (https://me.government.bg/)*

(68) *Şengör, A. M. C., Görür, N., and Saroglu, F., 1985, Strike-slip faulting and related basin formation in zones of tectonic escape: Turkey as a case study, in K.T. Biddle and N. Christie-Blick, eds., Strike-slip faulting and basin formation: Society of Economical Paleontologists and Mineralogists Special Publication, v. 37, p. 227–264.*

(69) *Siyako, M. and O. Huvaz, 2007, Eocene stratigraphic evolution of the Thrace Basin, Turkey: Sedimentary Geology, v. 198, no. 2007, p. 75–91.*

(70) *GDPA reports.*

(71) *NVentures Mediterranean and Europe Activity Updates, December 2019.*

(72) *Exploration: The Black Sea Hots Up, GEO ExPro Vol. 10, No. 1, 2013.*

(73) *Major Gas Discovery Offshore Turkey, 2020, GEO ExPro, Vol. 17, No. 5 – 2020.*

(74) *Teimuraz Gochitashvili, Oil and Gas Sector of GEORGIA in the Transition Period, TBILISI 2020, Meridian" Publishing House, 2020, ISBN 978-9941-25-866-4.*

Units, abbreviation and conversions

bbl	*barrel oil*
MMbbl	*Million barrels of oil*
MMbblo (e)	*Million barrels oil, (equivalent)*
Bcmg	*Billion cubic meter gas*
Tcmg	*Trillion cubic meter gas*
Bcfg	*Billion cubic feet gas*
Tcfg	*Trillion cubic feet gas*
t	*Metric ton*
MMt	*Million metric tons*

1 US barrel (oil)	*0.16 cubic meter (0,1589873)*
1 meter	*6,2898 barrels (oil)*
1 US barrel (oil)	*0.1364 metric ton*
1 metric ton	*7.33 barrels (oil)*
1 meter	*3.280839 feet*
1 cubic meter	*35.3146667 cubic feet*
1 cubic foot	*0.03 cubic meter*

Contingent resources

Quantities of petroleum which are estimated, on a given date, to be recoverable from known accumulations

Reserves

Those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.

Recoverable reserves

Commercial accumulations

GIIP

Gas initially in place, volume of gas in a reservoir before production

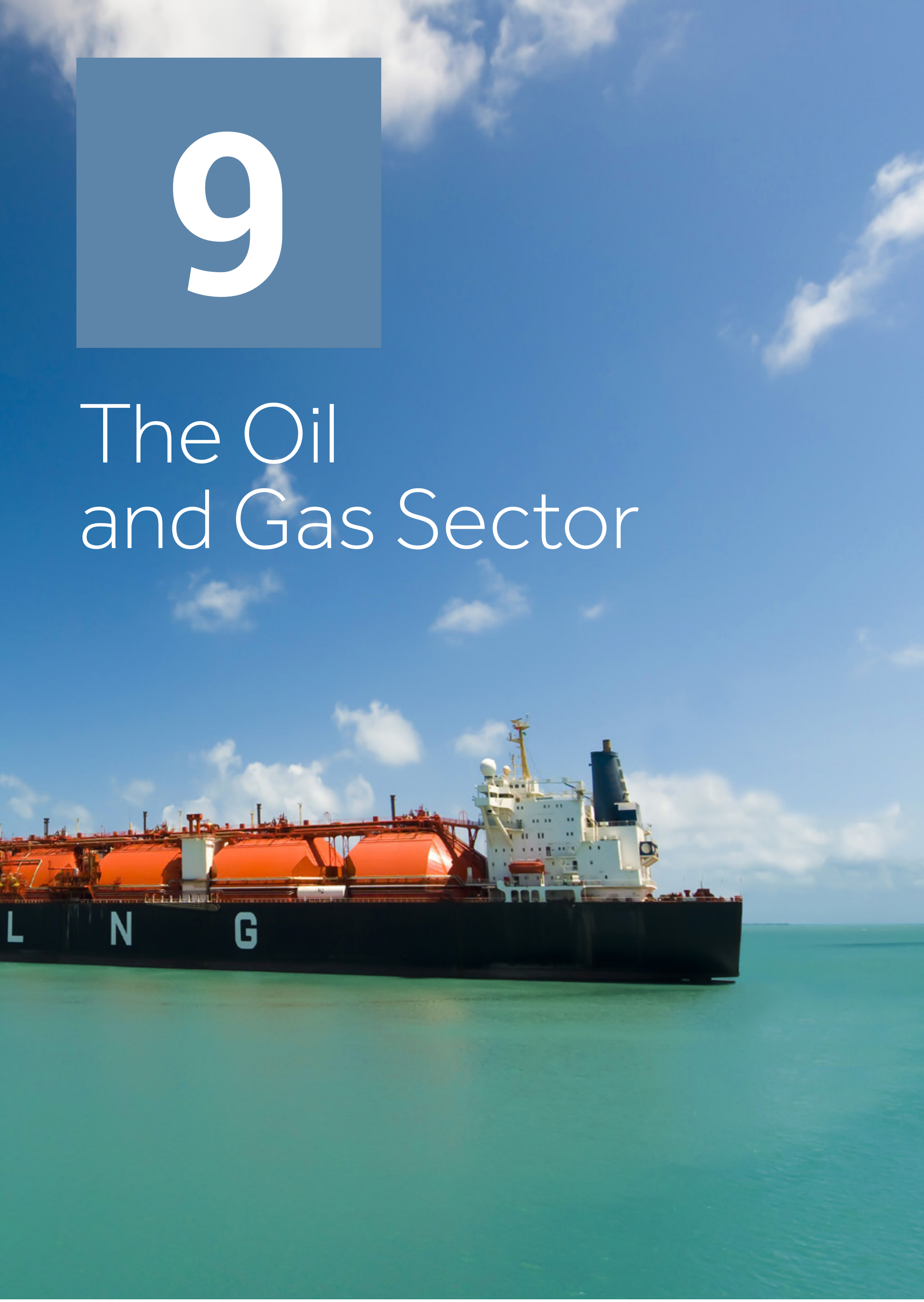
The Range of Uncertainty, reflects a reasonable range of estimated potentially recoverable volumes for an accumulation.

The range of uncertainty can be reflected in estimates for Proved Reserves (1P), Proved plus Probable Reserves (2P) and Proved plus Probable plus Possible Reserves (3P) scenarios.

* *Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.*

9

The Oil and Gas Sector



The Oil and Gas Sector

9.1 Oil Midstream and Downstream

9.1.1 A broad view of the Oil Sector

Although several countries in SEE are engaged in hydrocarbon exploration, despite very limited domestic oil reserves, as we saw in Chapter 8, and some of them are producers of oil and gas in their own right, the region is by far a net oil and gas importer. With almost 260,000 tonnes of oil and petroleum products consumed everyday (2019 data) by all 14 countries in the region[1], 87% of which is imported, SE Europe and the East Mediterranean are considered to be an important destination for oil exporters. A situation which has not changed much since publication of IENE's 2017 SEE Energy Outlook. On the contrary, oil import dependency has increased by 2%. Oil imports for most countries continue to play an important role in their finances, and depending on the prevailing international oil prices, oil imports represent a sizeable chunk of their GDP's and an even bigger one of their annual balance of payments account. Hence, the oil import bill exerts an important influence in the management of most countries' economies.

This section of the "Outlook" examines all aspects of the oil sector in the region including oil demand and consumption, oil related infrastructure, refining, oil prices and the oil retail market in the various countries.

As oil imports, like gas, have over the years emerged as key energy security factor many countries in the region have embarked upon ambitious hydrocarbon exploration programmes aiming to increase, or commence, oil and gas production (as we saw in Chapter 8) and thus lessen their dependence on hydrocarbon imports. Indigenous oil and gas production makes sense on both energy security and economic grounds as local production helps bolster state coffers, enhances energy security but also provides much needed independence in managing a country's energy resources.

Many countries in the region possess extensive oil related facilities in the form of oil loading terminals, oil pipelines, storage facilities such as tank farms, refineries and oil retail outlets. An attempt is made in this Outlook Report to record and analyse the oil activity in the region and to identify potential synergies and business opportunities while the investment potential is discussed in a separate Chapter (see Chapter 15). In short, the region is characterized by a very vibrant business activity in the oil sector with thousands of companies involved and billions worth of euros invested every year in order to maintain but also expand existing facilities. It is worth noting that biofuels will play an important role over the next years, acting as an emerging new market and they can be characterised as a key pillar of regional oil market transformation.

9.1.2 Oil Demand and Supply

A shy recovery of oil demand in sight

According to the IEA[1], the staggering inventory surplus that built up in 2020 is being worked off and global oil stocks, excluding strategic reserves, will return to pre-pandemic levels in 2021. And yet, there may be no return to ''normal'' for the oil market in the post-Covid era. The pandemic has forced rapid changes in behavior: from new working-from-home models to cuts in business and leisure air travel. At the same time, a number of governments, especially the USA and in the EU, are focusing on the potential for a sustainable recovery as a way to accelerate momentum towards a low-carbon future. Although not all OECD governments share this view, the outlook for oil demand has shifted lower as a result of these trends.

«These forces are creating a dilemma for oil-producing countries and companies that are reluctant to leave resources in the ground or build new capacity that could sit idle. But if this

[1] The following countries are included: Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Greece, Hungary, Kosovo, North Macedonia, Montenegro, Romania, Serbia, Slovenia and Turkey.

leads to a shortfall in investment, it could also have geopolitical implications and heighten the risk of supply shortages later on», noted the IEA in its mid-term Oil 2021 report [1].

Looking at the broader picture, demand recovery remains uneven. Global oil demand, still reeling from the effects of the pandemic, is unlikely to catch up fast with its pre-Covid trajectory. In 2020, global oil demand was nearly 9 mb/d below the level seen in 2019, and it is not expected to return to that level before 2023 according to estimates by both OPEC and the IEA. In the absence of more rapid policy intervention and behavioural changes, longer-term drivers of growth will continue to push up oil demand. As a result, by 2026, notes the IEA, global oil consumption is projected to reach 104.1 mb/d. This would represent an increase of 4.4 mb/d from 2019 levels (Table 9.1)[1].

Table 9.1 **World oil balance**

World oil demand and supply (mb/d)

	2019	1Q20	2Q20	3Q20	4Q20	2020	1Q21	2Q21	3Q21	4Q21	2021	2022	2023	2024	2025	2026
DEMAND																
Total OECD	47.7	45.4	37.6	42.3	43.1	42.1	43.3	43.8	45.4	46.5	44.7	45.8	46.2	46.2	46.0	45.8
Total Non-OECD	52.0	48.3	45.3	50.4	51.7	48.9	50.7	51.1	52.3	52.7	51.7	53.7	55.0	56.1	57.2	58.3
Total Demand[1]	99.7	93.8	82.9	92.7	94.7	91.0	93.9	94.9	97.7	99.2	96.5	99.4	101.2	102.3	103.2	104.1
SUPPLY																
Total OECD	28.5	29.9	26.9	27.1	27.8	27.9	27.8	28.1	28.3	28.7	28.2	29.0	29.6	29.9	29.9	29.7
Total Non-OECD	32.0	32.3	30.0	29.7	29.9	30.5	30.3	30.8	30.8	30.7	30.6	31.5	32.0	32.0	32.1	32.1
Processing Gains[2]	2.4	2.3	2.0	2.1	2.1	2.1	2.1	2.2	2.3	2.3	2.2	2.4	2.4	2.4	2.5	2.5
Global Biofuels	2.8	2.2	2.5	3.1	2.6	2.6	2.3	2.9	3.2	2.9	2.8	3.0	3.1	3.2	3.3	3.3
Total Non-OPEC[3]	65.6	66.7	61.3	61.9	62.4	63.1	62.5	63.9	64.5	64.6	63.9	66.0	67.1	67.5	67.7	67.6
OPEC																
Crude	29.5	28.2	25.6	24.1	24.9	25.7										
OPEC NGLs	5.4	5.4	5.2	5.1	5.2	5.2	5.2	5.3	5.3	5.3	5.3	5.5	5.5	5.6	5.6	5.7
Total OPEC[3]	34.9	33.6	30.8	29.2	30.0	30.9										
Total Supply	100.5	100.2	92.1	91.1	92.4	93.9										
Memo items:																
Call on OPEC crude + Stock ch.[4]	28.7	21.7	16.4	25.7	27.2	22.8	26.2	25.7	27.9	29.3	27.3	28.0	28.6	29.2	29.9	30.8

1. Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
2. Net volumetric gains and losses in the refining process and marine transportation losses.
3. Total Non-OPEC excludes all countries that are currently members of OPEC. Total OPEC comprises all countries which are current OPEC members.
4. Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

Source: IEA

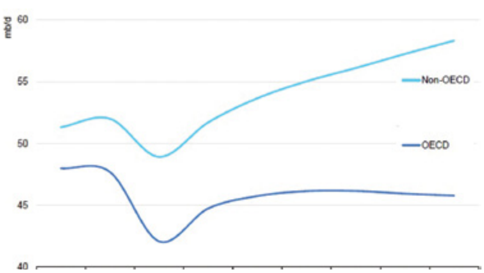
All of this demand growth relative to 2019 is expected to come from emerging and developing economies, underpinned by rising populations and incomes. Asian oil demand will continue to rise strongly, albeit at a slower pace than in the recent past. OECD demand, by contrast, is not forecast to return to pre-crisis levels, says the IEA. The speed and depth of the recovery is likely to be uneven both geographically and in terms of sectors and products. Gasoline demand is unlikely to return to 2019 levels, as efficiency gains and the shift to electric vehicles eclipse robust mobility growth in the developing world. Aviation fuels, the hardest hit by the crisis, are expected to slowly return to 2019 levels by 2024, but the spread of online meetings could permanently alter business travel trends. The petrochemical industry remains a pillar of growth over the forecast period. Ethane, LPG and naphtha together account for 70% of the projected increase in oil product demand to 2026 [1].

European demand to contract after the Covid recovery

As projected by the IEA, the North American and European regions will witness the largest demand growth within OECD in percentage terms in 2021 (6-7%), as they catch up with the volume lost in 2020 to the pandemic. The IEA estimates that oil demand will grow by 1.6 mb/d in North America and by 740 kb/d in Europe, or around half the decrease seen in 2020. After growing by 2% in 2022, growth in the OECD is expected to grind to a halt as higher energy efficiency in the transport sector, penetration of EVs and substitution by other energies curbs fuel use. Other factors, such as teleworking and less business travel, will also contribute, albeit marginally.

In Europe, including SEE countries, the IEA notes that, consumption will increase by 740 kb/d in 2021, 110 kb/d in 2022 and 160 kb/d in 2023. Growth then is likely to fall to 20 kb/d in 2024 and will turn negative in 2025. By 2026, it will still be below its 2019 level. Gasoline and diesel grow in the early part of the forecast period, but decline after 2023. Jet fuel and kerosene demand grows by 160 kb/d in 2021. As the international aviation sector reopens, demand rises more strongly in 2022 (330 kb/d) and 2023 (280 kb/d), when it returns to its 2019 consumption level. Petrochemical feedstocks LPG, ethane and naphtha see little demand growth [1].

Figure 9.1 **World oil demand - OECD oil demand will never recover above 2019 levels**



Source: IEA

Supply growth curtailed by spending cuts

The Covid-induced demand shock and a shifting momentum towards investment in clean energy are set to slow the expansion of the world's oil production capacity over the next five years, says the IEA. At the same time, the historic collapse in demand in 2020 resulted in a record 9 mb/d spare production capacity cushion that would keep global markets comfortable in the short term. Consequently, investments and expansion plans have been scaled back. In 2020, operators spent one-third less than planned at the start of the year (and 30% less than in 2019). In 2021, total upstream investment is expected to rise only marginally. This has also affected SE Europe and the EastMed region as new exploration activity is not expected to return to normal levels before 4Q 2021 and 1H 2022.

«Those sharp spending cuts and project delays are already constraining supply growth across the globe, with world oil production capacity now set to increase by 5 mb/d by 2026. In the absence of stronger policy action (meant to curtail rising demand in line with climate change mitigation policies), global oil production would need to rise 10.2 mb/d by 2026 to meet the expected rebound in demand», observed the IEA according to OPEC sources. Producers from the Middle East are expected to provide half of the increase, largely from existing shut-in capacity. If Iran remains under sanctions, which is most likely in the foreseeable future, keeping the world oil market in balance may require Saudi Arabia, Iraq, the UAE and Kuwait – with their surplus capacity – to pump at or near record highs [1].

SEE countries have on the whole very limited domestic oil reserves and are largely net importers of crude oil. Indeed, only 11 percent of the oil refined in SEE refineries originates from oil fields within the region. This dependence on imports is primarily the result of depletion of existing oil reserves with few opportunities for new exploration.

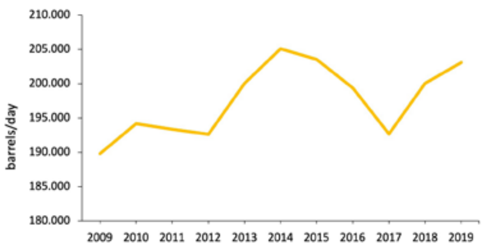
Some SEE countries have significant reserves of shale rock suitable for oil production, but so far they have not acquired the technology or developed a business case to exploit these resources. A detailed discussion on this and related matters is made in Chapter 8.

Figure 9.31 illustrates that six countries (Bosnia & Herzegovina, Bulgaria, Cyprus, North Macedonia, Greece, Montenegro and Kosovo) are fully dependent on oil imports, while Croatia, Serbia and Turkey depend for more than 50% of their oil imports, with Albania and Romania covering a substantial part of their needs from indigenous resources. The number of oil barrels produced per day (bbl/ day) in SEE was nearly 203,096 in 2019 which was 1,5 % higher than in 2013. One third of this quantity was produced in Romania. The increase in crude oil production in the region by about 13,300 bbl/day over the last 10 years was the result of an increase in oil production by 74% in Albania and 31% in Turkey [2]. Albania is the only country in the region that continues to export crude oil (mainly to Italy). The oil produced in Romania and four other Balkan states –Turkey, Croatia, Serbia and Albania – corresponded to 89% of the total oil output in SEE.

In 2019, the final consumption of oil and petroleum products in SEE stood at approximately to 95,000,000 tonnes or close to nine times as much as the domestic production. The shortage was made up by imports of crude oil and petroleum products. In 2019, the increase in SE Europe's oil consumption continued, due to cold weather in the early part of the year and lower oil prices. This trend, which was interrupted during the Covid-19 period, is most likely to continue in the years beyond 2022 due to a stronger macroeconomic and growth outlook mainly driven by the West Balkans performance. Bosnia & Herzegovina, Montenegro, Kosovo and Albania are considered as emerging markets with regard to oil product consumption. This trend will become ever more intense if oil prices remain at their current level and will not move near the $100 per barrel mark. Although, oil demand from non-transport sectors is expected to experience an incremental fall.

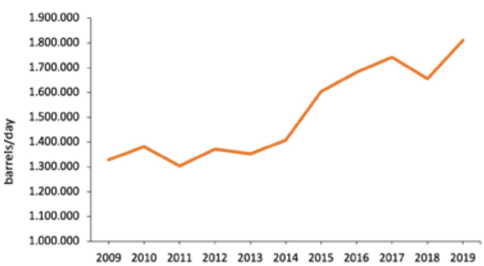
Crude oil production in SE Europe, peaked at 205,089 barrels/day in 2014, while it reached its lowest point at 192,696 barrels/day in 2017 (Figure 9.2). Over the past two years, 2018 and 2019, production of crude oil stabilized, after the fluctuations observed in the previous years. Gross inland consumption of crude oil shows an upward trend over the period 2009-2019, with the consumption in 2019 showing an increase of 36.2% compared to 2009 (Figure 9.3) [2].

Figure 9.2 **Evolution of primary production of crude oil in SE Europe**



Source: Eurostat

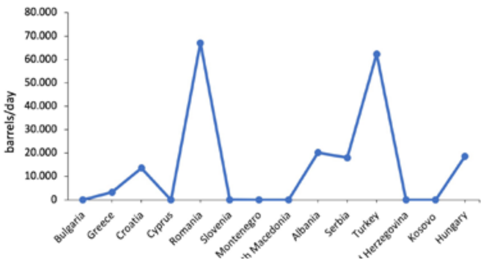
Figure 9.3 **Evolution of gross inland consumption of crude oil in SE Europe**



Source: Eurostat

The total production of crude oil in SE Europe in 2019 amounted to 203,096 barrels/day. The top oil producer in 2019 was Romania (67,000 barrels/day), followed by Turkey (63,000 barrels/day) and Albania (20,182 barrels/day) (Figure 9.4).

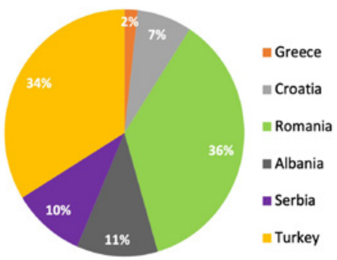
Figure 9.4 **Primary production of crude oil in SE Europe (2019) by country**



Source: Eurostat

The crude oil produced in 2019 in SE Europe, was 1,5% higher than in 2018 and 5,4% higher compared to 2017. Romania and Turkey amounted for more than half of the total oil production in 2019. The production of crude oil in Greece in 2019 was insignificant as compared to domestic final consumption of oil products. Although Romania accounted for 33% of total oil production in SE Europe in 2019, it experienced a percentage decrease of 22% in the period 2009-2019.

Figure 9.5 **Share of crude oil production in SE Europe by country (2019)**



Source: Eurostat

Table 9.2 summarizes the production and consumption of crude oil in countries of SE Europe in 2019 [2].

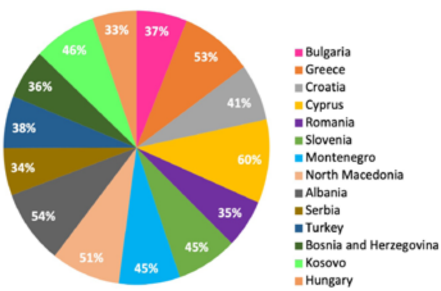
Table 9.2 **Primary Crude Oil Production and Refining in SE Europe (2019)**

Country	**Crude Oil Production (barrels/day)**	**Gross Inland Crude Oil Refined (barrels/day)**
Bulgaria	0	138,934
Greece	3,302	458,630
Croatia	13,600	53,136
Cyprus	0	0
Hungary	18,644	136,425
Romania	67,040	238,447
Slovenia	5	0
Montenegro	0	0
North Macedonia	0	0
Albania	20,183	6,732
Serbia	18,026	66,528
Turkey	62,297	709,676
Bosnia and Herzegovina	0	1,563
Kosovo	0	0
Total	**203,096**	**1,810,071**

Source: Eurostat

Oil and petroleum products represent 43% on average of the final energy consumption in the selected SE Europe countries (Figure 9.6). Cyprus possesses the largest portion of oil and petroleum products in its final energy consumption at 60%, followed by Albania (54%) and Greece (53%). By contrast, Hungary reports the smallest percentage of 33%.

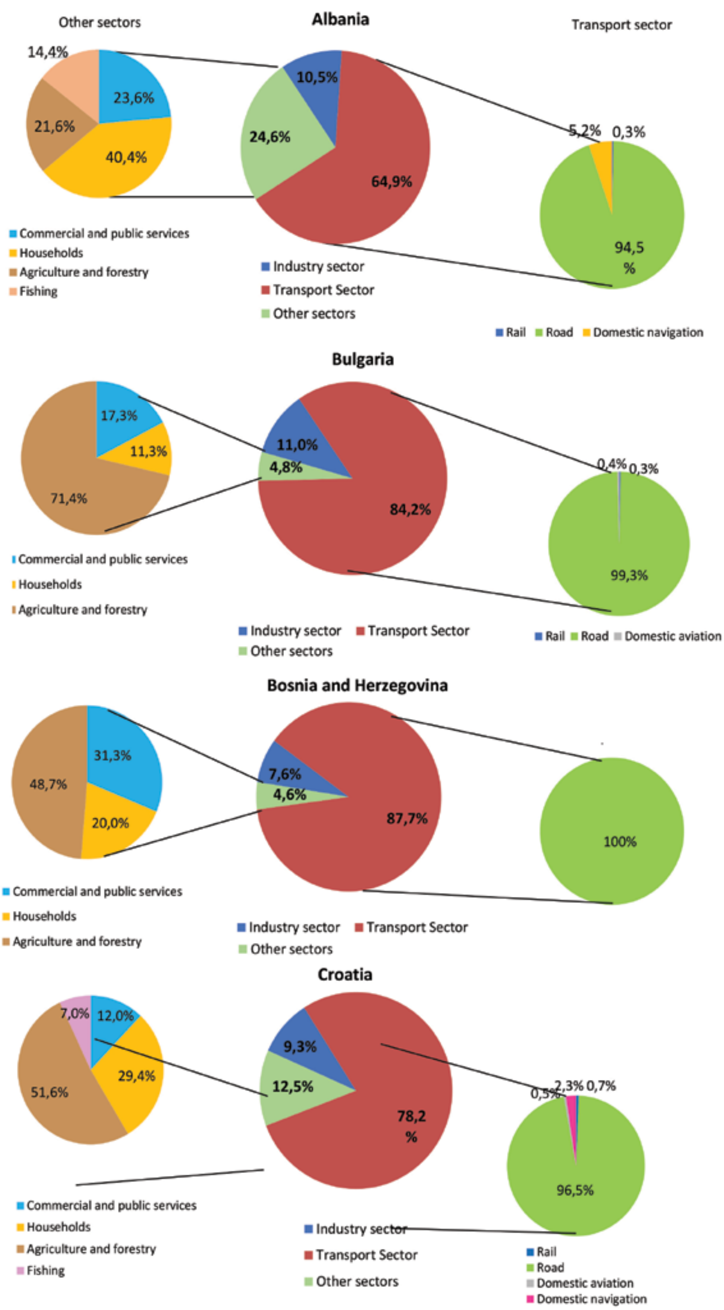
Figure 9.6 **Share of oil and petroleum products in final energy consumption in SE Europe (2019)**



Source: Eurostat

Transport remains by far the largest oil consumption contributor in SEE. Hence, a more detailed analysis is pertinent. The series of pie charts in Figure 9.7 illustrate that the transport sector accounted for the biggest share of oil and petroleum products consumption in the selected countries of SE Europe in 2019. Transport share in total oil consumption varied from 61.3% in Kosovo to 87.7% in Bosnia Herzegovina. Road transport was by far the leading transport mode for oil and petroleum products consumption, with all the countries, except Greece (84.9%), reporting a percentage above 90%. In case of Greece a sizeable amount of transport oil corresponds to marine use.

Figure 9.7 **Final energy consumption of oil and petroleum products by sector, 2019**

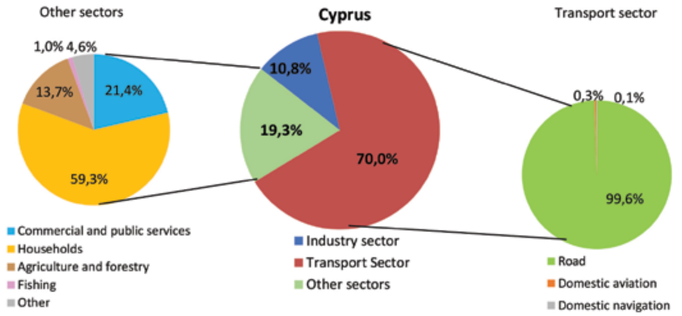


Final energy consumption of oil and petroleum products: 1,101.2 ktoe

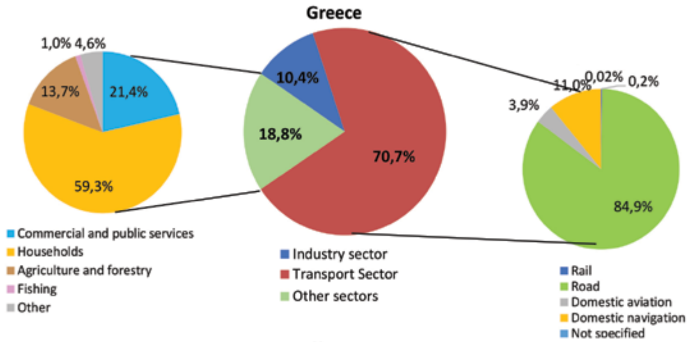
Final energy consumption of oil and petroleum products: 3,631.4 ktoe

Final energy consumption of oil and petroleum products: 1498.5 ktoe

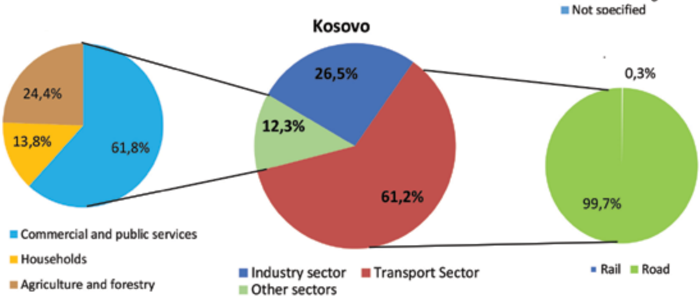
Final energy consumption of oil and petroleum products: 2,741.8 ktoe



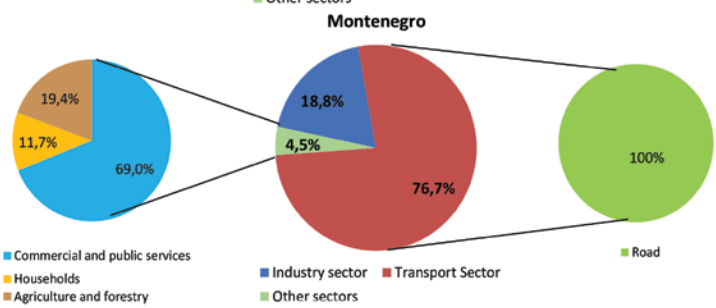
Final energy consumption of oil and petroleum products: 974.9 ktoe



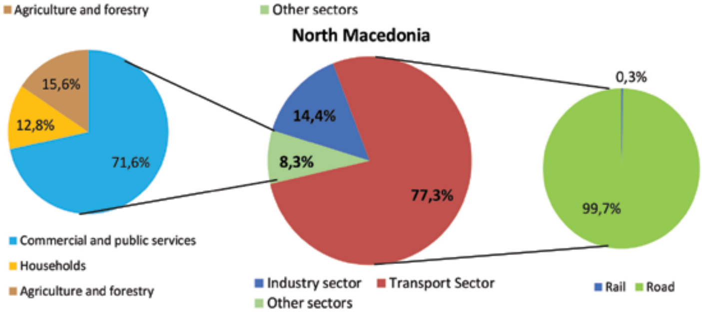
Final energy consumption of oil and petroleum products: 8,237.3 ktoe



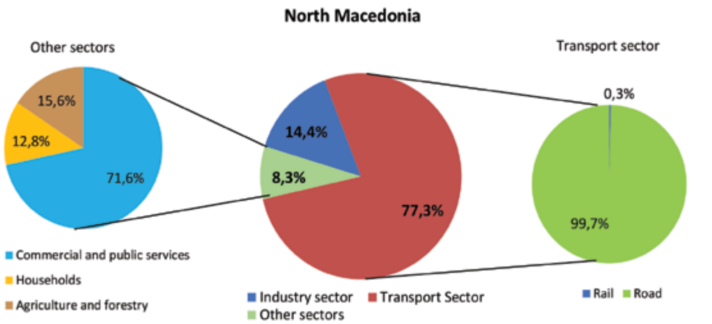
Final energy consumption of oil and petroleum products: 699.3 ktoe



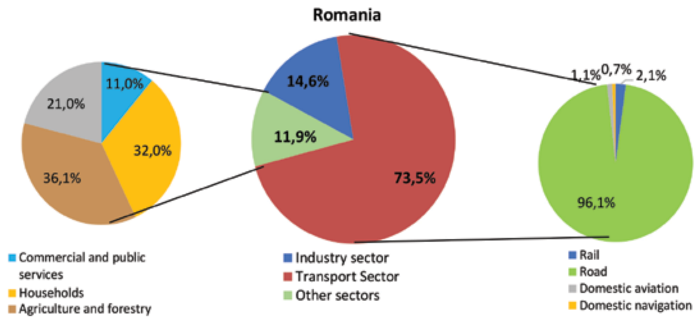
Final energy consumption of oil and petroleum products: 343.9 ktoe



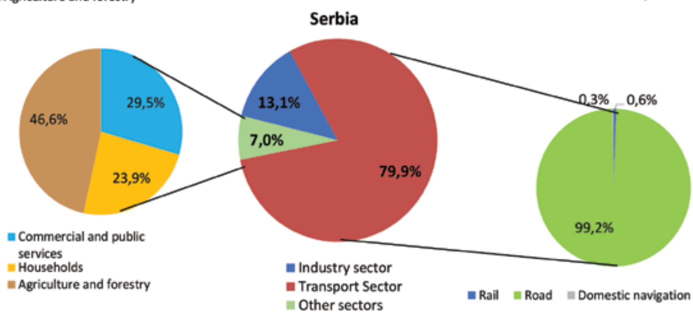
Final energy consumption of oil and petroleum products: 979.1 ktoe



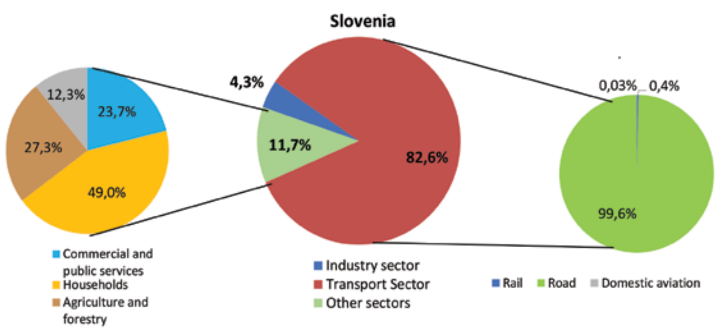
Final energy consumption of oil and petroleum products: 979.1 ktoe



Final energy consumption of oil and petroleum products: 8,258.0 ktoe

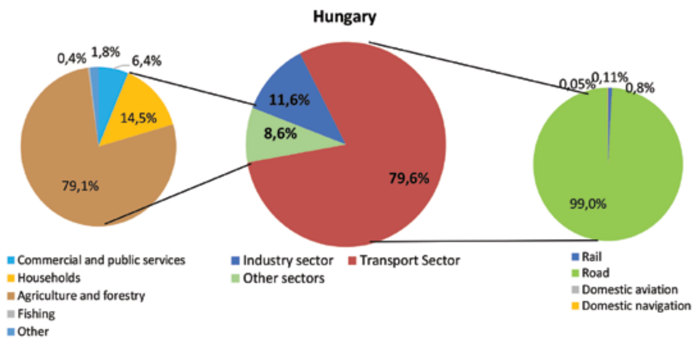


Final energy consumption of oil and petroleum products: 2,832.3 ktoe

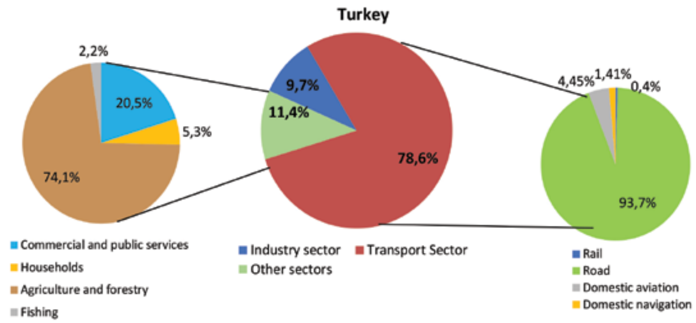


Final energy consumption of oil and petroleum products: 2,188.4 ktoe

Figure 9.7 (continued)



Final energy consumption of oil and petroleum products: 5,878.5 ktoe



Final energy consumption of oil and petroleum products: 35,289.4 ktoe

Source: Eurostat Energy Balances

As far as petroleum products are concerned, gas oil and diesel oil was the most widely consumed petroleum product in the SEE countries for the period 2009-2019. The total values consumed per country and the breakdown per products for each country, are shown in Figure 9.8. In the period shortly after the economic crisis (2010-2016) most countries followed a decreased consumption pattern of petroleum products, while the next three years saw a resurge with some fluctuations.

Figure 9.8 **Final consumption of petroleum products in thousand tonnes (2009 – 2019)**

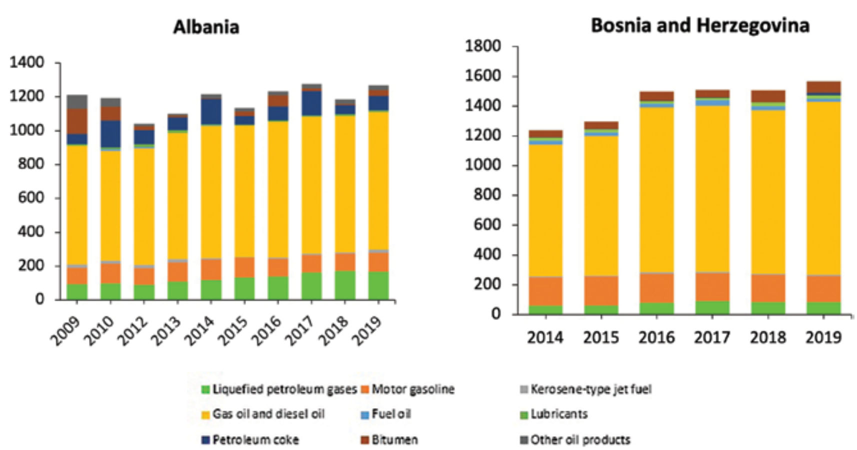
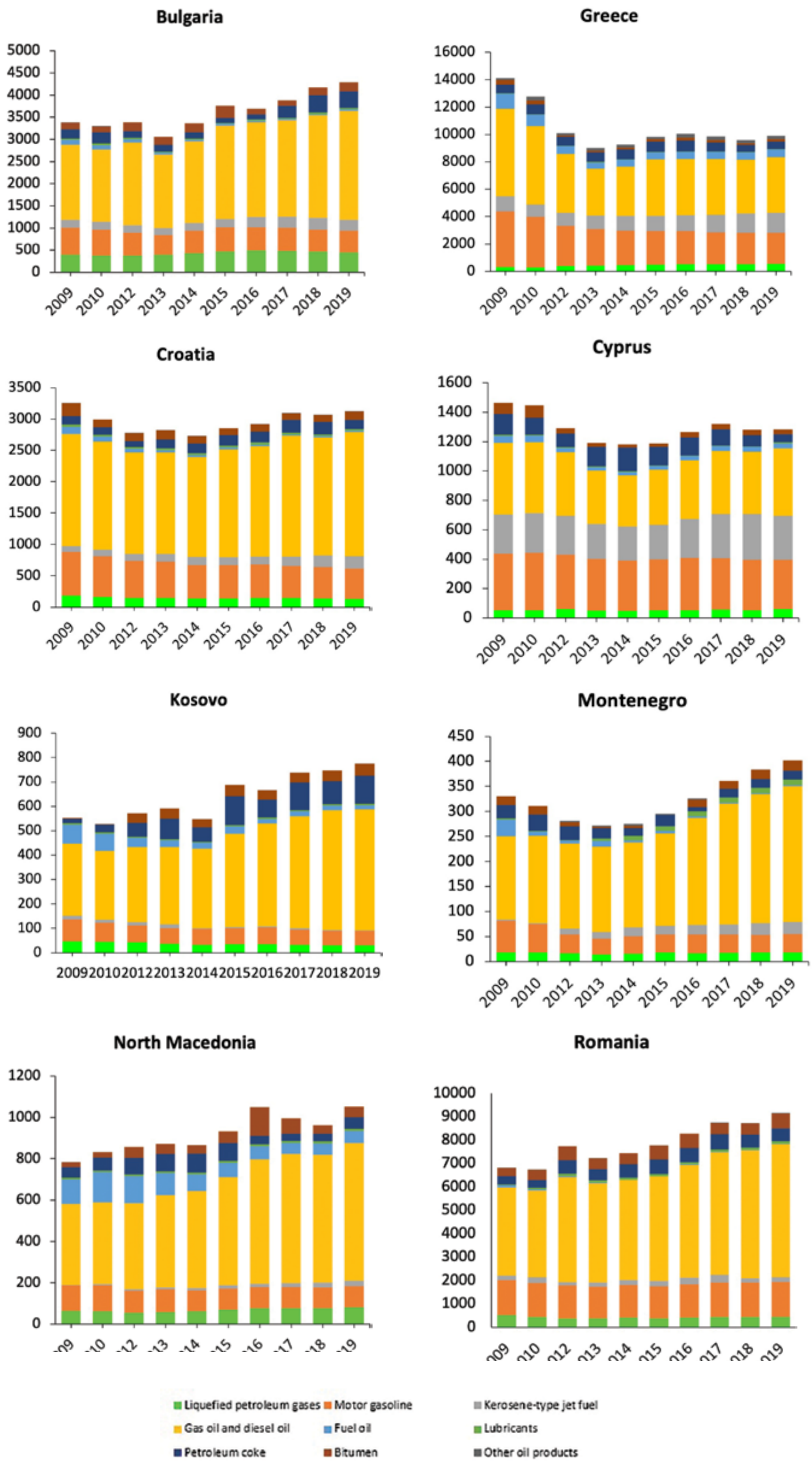
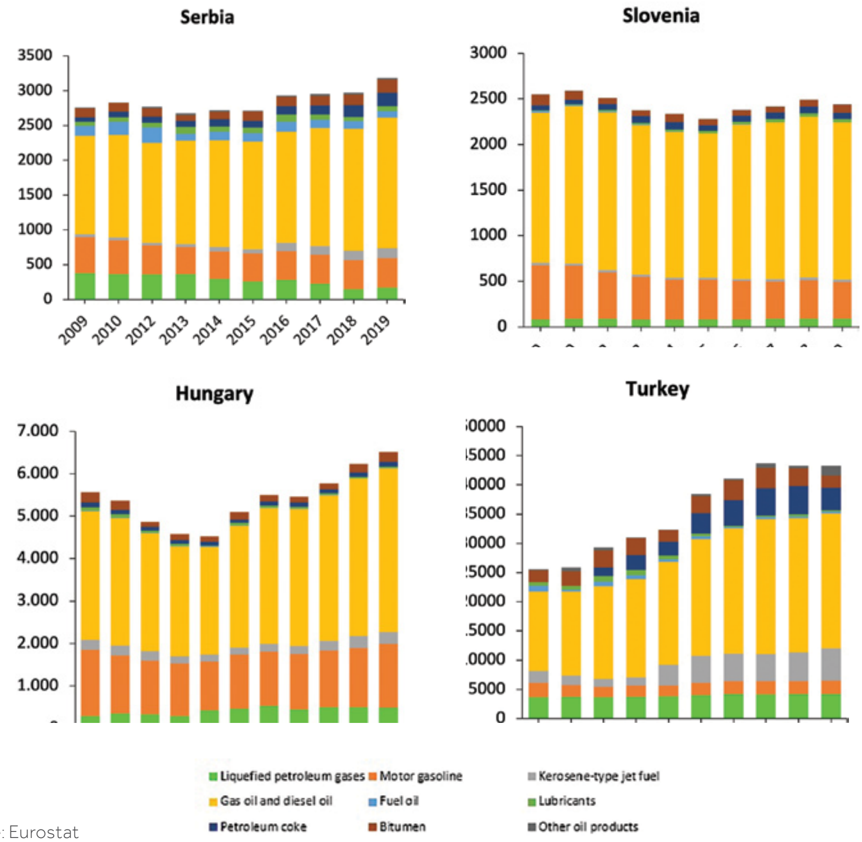


Figure 9.8 (continued)





Source: Eurostat

In the pages which follow, some notes for each country's oil demand and supply situation are given.

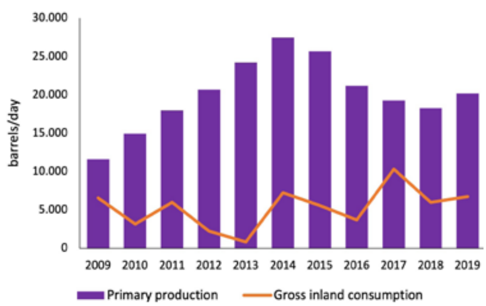
Albania

Albania's energy mix is dominated by fossil fuels – mainly crude oil – which account for more than half of total primary energy supply (TPES). However, domestic production is not able to meet demand; Albania is therefore, on average, a net energy importer. Domestic supply consists mainly of oil, electricity and firewood. Oil and electricity are the main indigenous primary energy sources in Albania which covered 45.6% and 36.8% respectively, of total primary energy supply contributing together 82.4% of the primary energy.

Oil production followed an upward trend during 2009-2014, where it peaked at 27,470 barrels/day, and then followed a decrease of 26.5% in 2019, compared to 2014.

During 2016-2019 crude oil production stabilized at an equilibrium of around 20,000 barrels/day. Gross in land production in 2019 stood at 6,732 barrels/day (Figure 9.9).

Figure 9.9 **Evolution of crude oil production and gross inland consumption in Albania**



Source: Eurostat

Bosnia and Herzegovina

Bosnia and Herzegovina does not have a domestic production of crude oil and imports all necessary quantities. Generally, Bosnia and Herzegovina imports crude oil and refines a variety of petroleum products. Production of petroleum products in Bosnia and Herzegovina for 2018 reached 701.321 tons, while the amount of petroleum products available for supply stood at 1.639.585 tons.

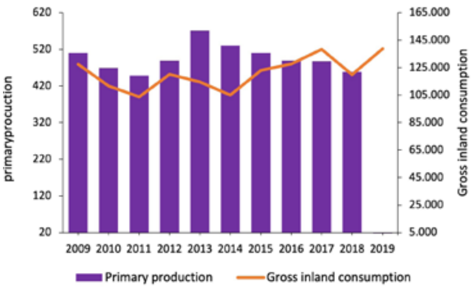
The final consumption in 2018 was 1.504.929 tons. The final energy consumption share in the total final consumption of petroleum products was 93% and the final non-energy consumption share was 7%. In the total final energy consumption of 1.401.257 tons of petroleum products in 2018, the largest share belongs to the transport sector (85.7%), households participate with 1.8%, industry with 6.6%, while the other, construction and agriculture sectors, participate with 5.9%. Gross inland consumption in Bosnia-Herzegovina is expected to increase up to around 7 Mtoe over the analysed periods.

The mix is not expected to significantly change, coal is seen to remain the key energy form of the system (always above 3.7 Mtoe in the medium-long term, similar values as in the base year), with limited/slow increase of renewable energy use (from around 1 Mtoe in 2020 to 1.45 Mtoe in 2040).

Bulgaria

Crude oil participated with an almost negligible share in primary energy production. However, oil is among the main sources of energy used in Bulgaria, with stable presence in gross inland consumption, -at around 23.5% for the period 2014-2018, as it represents the main energy source for transportation.

Figure 9.10 **Primary production and gross inland consumption of crude oil in Bulgaria (barrels/day)**



Source: Eurostat

Petroleum products participated in final energy consumption with the highest share of 32-36% over the period 2014-2018. Traditionally, the main consumer of petroleum products is the transport sector, particularly road transport, with a share of about 83-87% in final energy consumption.

The country is entirely dependent on imports for the supply of crude oil. The major trading partners are Russia and Ukraine, which combined amount to more than 90% of the country's total imports and hence, the geographical diversification of oil supplies is rather limited. The rest of the oil supplies are imported from: Malta, Turkey, Kazakhstan, Egypt. The degree of petroleum products energy dependence is among the highest in the EU. The indicator has remained broadly stable during 2014-2018 with negligible fluctuations, but in 2019 it exceeded 100%, indicating a stock build.

Table 9.3 **Energy dependence of total petroleum products (%), 2014-2019**

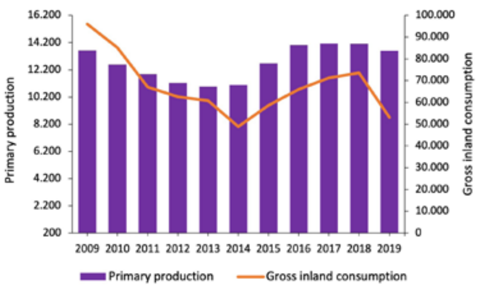
	2014	2015	2016	2017	2018	2019
Energy dependence of total petroleum products	99%	100.5%	99%	101.1%	99.5%	102.6%

Source: Eurostat

Croatia

Crude oil production in Croatia reached its lowest point in 2013 (10,977 barrels/day) and its peak in 2017 (14,114 barrels/day). Gross inland consumption reached the second lowest point in 2019 (53,136 barrels/day), after 2014 (Figure 9.11).

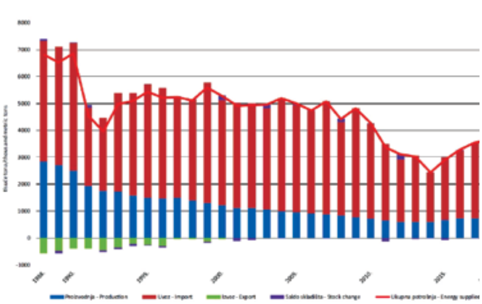
Figure 9.11 **Evolution of primary production and gross inland consumption of crude oil in Croatia (barrels/day)**



Source: Eurostat

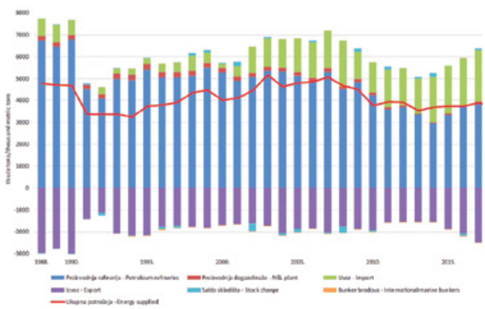
Total consumption of liquid fuels in 2018 amounted 134.52 PJ which is the highest share of all primary products in Croatia (share of 32.9%). In terms of final energy consumption, the share of liquid fuels is even larger and amounted to 40,7% in 2018. Croatia produced 732.1 thousand tons of liquid fuels which is about 20% of the country's liquid fuels needs. Total reserves of oil and condensate amounted from 6,998.1 thousand m3 for P1 to 10,009.8 thousand m3 for 3P.

Figure 9.12 **Crude oil supply in Croatia**



Source: EIHP

Figure 9.13 **Petroleum products supply in Croatia**



Source: EIHP

Cyprus

In 2018, 60.1% of energy demand was covered by the use of oil and petroleum products. Similarly, the energy supply in the period 2016-2018 was mostly based on oil products. The oil and petroleum products share decreased from 91.9% in 2016 to 88.1% in 2018.

The total final consumption of oil products in 2018 amounted to 1.78 mtoe (including imports of oil for electricity generation). The oil products were mainly used in the transportation sector, with a consumption of 1.01 mtoe, i.e. approximately 56.7% of the total final consumption of oil products in 2018. Services (including commerce & hotels) consumed 0,21 mtoe, representing 12% of the total oil consumption, agriculture consumed 0.039 mtoe, representing 2% of the total oil consumption, households consumed 0.324 mtoe, representing 18% of the total oil consumption, while the industry consumed 0.189 mtoe, 11% of the total oil consumption in 2018.

Cyprus exhibits a high degree of dependence on imported oil products (Table 9.4), while the main fuels currently used in power generation are fuel oil and diesel oil. The various oil products imported are used in the transport, households, services, agriculture and industry sectors.

Table 9.4 **Oil and petroleum products imports dependency**

	2014	2015	2016	2017	2018	2019
Energy dependence of oil and petroleum products	97.9%	102.8%	100.7%	100.9%	99.2%	99.7%

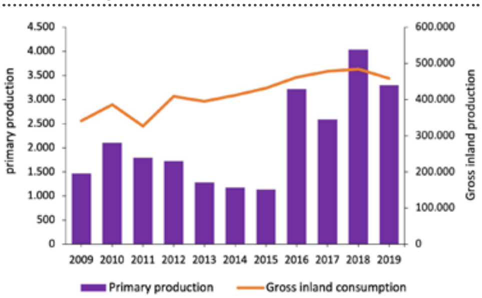
Source: Eurostat

Imported oil products include LPG, unleaded gasoline, jet fuel (ATF - Aviation Turbine Fuel), kerosene, diesel, gasoil, LFO, HFO (mainly used for power generation purposes by EAC), bitumen (used in road asphalt) and pet coke (used for cement production by the Vasilikos Cement Company). Apart from these, also biofuel blends, marine bunker fuels and lubricants are imported, which have other own applications. Imports of oil and petroleum products, except HFO (i.e. LPG, gasoline, kerosene, diesel, heating oil, marine gasoil, LFO) constituted 61.5% (1.6 mtoe) of the total oil products imports in 2018, while 13.7% (0.36 mtoe) concerned imports of HFO, which was used almost exclusively for power generation. The import of pet-coke reached 0.05 mtoe (1.9% of total oil-products supply) and the rest amounted to the import of bitumen (0.021 mtoe) for road construction purposes (non-energy use).

Greece

Crude oil production in Greece reached 3,302 barrels per day in 2019, recording a 18.3% decrease from 2018. Gross inland consumption showed a Compound Annual Growth Rate (CARG) of 3% for the period 2009-2019 (Figure 9.14).

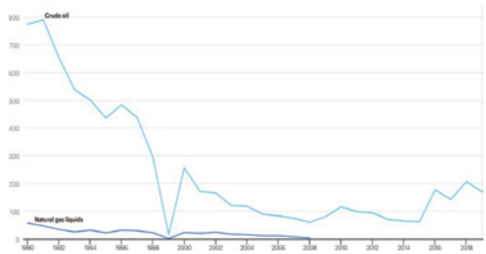
Figure 9.14 **Evolution of primary production and gross inland consumption of crude oil in Greece (barrels/day)**



Source: Eurostat

According to data from IEA [2], the production of crude oil in Greece in 2018 was insignificant (0.21 million tons, Mt) as compared to domestic final consumption of oil products at approximately 8.8 Mt in the same year (Figure 9.15).

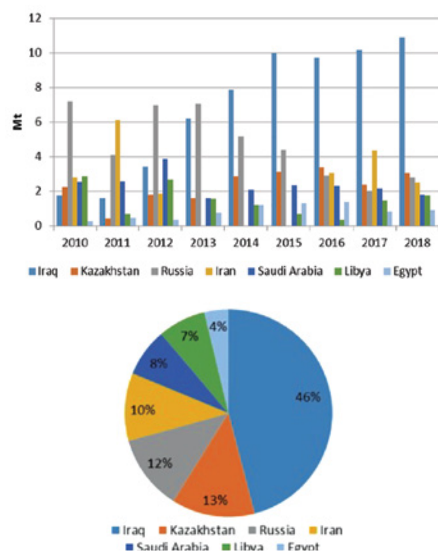
Figure 9.15 **Evolution of oil production in Greece**



Source: IEA

Greece depends on imports of large quantities of crude oil in order to cover its needs. Iraq was the biggest crude oil supplier to Greece in 2018 with 10.9 Mt, followed by Kazakhstan and Russia with 3.1 Mt and 2.8 Mt respectively. Imports from Iraq only accounted for 46% of total crude oil imports in Greece in 2018, which amounted to approx. 23.7 Mt (Figure 9.16).

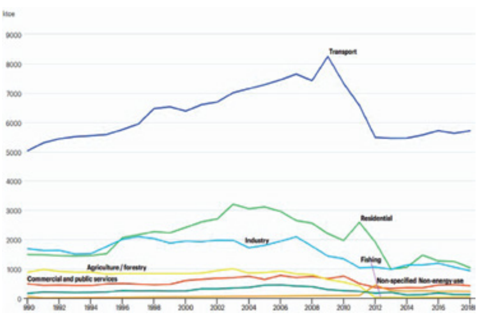
Figure 9.16 **Greece's Crude Oil Imports by Country**



Source: Ministry of Energy and Environment

Imported crude oil is refined into oil products at four domestic refineries. Greece has increased considerably its refining capability in recent years, with exports of oil products at 20 million tons in 2018, according to IEA data. Greece also imports oil products, with imports at 3.8 million tons in 2018. Over the period 2005-2015, oil consumption in Greece recorded a sudden drop by one third due to the economic crisis of 2008 and the Greek financial crisis that ensued, especially after 2009. In recent years, however, oil consumption recovered, rising by 9% between 2013 and 2015, mainly in transport and to an extent in the residential sector (Figure 9.17).

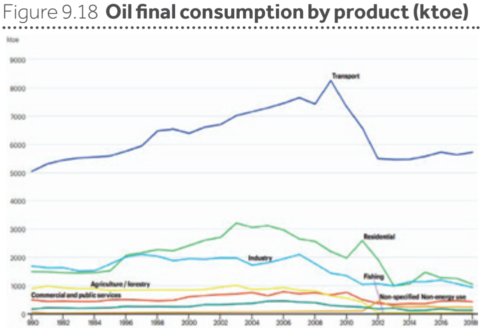
Figure 9.17 **Oil consumption by sector (ktoe)**



Source: IEA

The transport sector consumed 5.6 Mtoe of oil in 2017 or 50% of total oil consumption. Road transport accounts for 87% of total oil consumption in transport, followed by domestic shipping at 10% and smaller shares for domestic air and railway transport. The transport sector mainly consumes diesel and gasoline, which together account for 62% of total oil consumption in Greece (Figure 9.18).

Figure 9.18 **Oil final consumption by product (ktoe)**



Source: IEA

Approximately one third of the diesel is consumed in the residential sector for space heating. Heating oil represents one third of total residential energy consumption, the fourth highest share among IEA member-states. Residential oil consumption was considerably higher before the financial crisis (2009-2018). More specifically, it declined by 62% between 2011 and 2014, mainly due to a conjunction of high heating oil prices, reduced household income, and increased penetration of natural gas use because of a change in government policy (change of fuel in favour of biomass and natural gas). Consumption rose again in 2015.

Furthermore, Greece, in comparison to other countries, consumes a higher percentage of oil in power generation. Oil production units located on the islands accounted for 11% of total electricity generation in 2015, which was the highest among all IEA member-states. This is because many of the Greek islands are not yet connected to the mainland power grid but are supplied by autonomous production stations operating with oil-fired units (diesel and fuel oil).

Kosovo

Kosovo has neither domestic reserves of crude oil nor capacities for refining it and therefore does not import crude oil. Kosovo is net importer of petroleum products, and produces only heavy fuel oil for heating from imported raw material amounting approximately 30% of the consumption of heavy fuel oil for heating.

There are four licensed production plants, which currently produce heavy fuel oil with less than 1% of sulphur content; heavy fuel oil with less than 1% sulphur content is produced by mixing heavy fuel oil containing over 1% sulphur with light oils such as gasoline and kerosene [4]. Kosovo is net importer of oil products. Since there are negligible amounts of domestic production and exports, almost all consumption within the country is covered by imports (Table 9.5). In recent years the total imports of oil products did not have significant upward trend, but only slight variations.

Table 9.5 **Imports – Exports of petroleum products**

Petroleum Products - 2018 [in tons]			
Type	Imports	Exports	Consumption
Benzine	58,881.9	0	58,881.9
Biodizel	0.0	0	0.0
Bitumen	46,408.9	214.3	46,194.6
Dizel	494,247.6	0	494,247.6
Bottled natural gas	687.1	2	685.1
Gazoilet	5,506.4	0	5,506.4
LPG	30,537.1	0	30,537.1
Jet fuel	2,988.2	0	2,988.2
Koks nafte	103,954.9	0	103,954.9
Mazut	18,701.6	0	18,701.6
Lubricants	5,780.1	177.3	5,602.8
Total	767,693.8	393.6	767,300.2

Source: Kosovo Statistics Agency

Kosovo is almost 100% dependent on imports of oil products with the majority of them originating from regional countries (Table 9.6).

Table 9.6 **Origin of oil product imports in Kosovo, 2019**

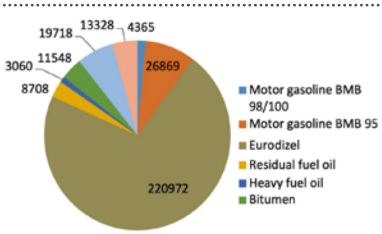
ORIGIN OF OIL PRODUCTS IMPORTS [%]		
Country	Petroleum	Diesel
Albania	0.00%	17.90%
Bosnia & Hercegovina	0.00%	0.00%
Montenegro	0.00%	0.00%
Greece	56.28%	45.65%
Serbia	39.60%	20.62%
Macedonia	3.82%	15.70%
Croatia	0.30%	0.13%
Total	100%	100%

Source: Statement of Security of Supply for Kosovo 2019

Montenegro

Montenegro does not have its own oil production or refining industry, and all oil products are imported. Total consumption of oil products in 2019 amounted 308,568 tons, out of which diesel corresponds to 220,972 tons, which is the most widely used oil product in Montenegro with a share of 72% in total consumption (Figure 9.19).

Figure 9.19 **Oil and petroleum products balance in tons for 2019**



Source: Ministry of Economy of Montenegro 2019

Consumption of oil derivatives in 2019 amounted to 13,053 TJ while 15,373 TJ use is anticipated for 2020. Oil derivate consumption amounted around 38% of total energy consumption in the country.

The Ministry of Economy of Montenegro anticipated an increase of oil product consumption by 17% in 2020. As significant increase is anticipated for diesel which is mainly used in the transport sector, as well as more than doubling of the consumption of bitumen as it is used for the construction of the Bar-Boljare highway.

Overall, the consumption of oil products decreased by 19% over the last decade. The trend of reduced consumption is mainly due to a sharp decrease in the consumption of fuel oil (mazut). The latter is associated with the decline in industrial production of aluminium oxide. The consumption of diesel and kerosene has increased by 43% and 69%, respectively, and is related to the growing energy demand of vehicle and airplane fleets. As of 2016, 96% of diesel was used by transport, and the remaining 4% was used as a heating fuel.

The transport sector dominates the consumption of oil products. The sector's share has been increasing over time, reflecting not only the increasing demand of the transport sector, but also the decline in industrial production since 2009.

Republic of North Macedonia

In 2019, OKTA Oil Refinery AD Skopje didn't import crude oil in the Republic of North Macedonia, and due to that there wasn't processing of crude oil and production of oil derivatives on the domestic market.

The overall imported quantities of oil derivatives in the Republic of North Macedonia, in 2019, amounted to 1,143,276 tons, which is by 15.76 % higher in relation to the imported quantities of oil derivatives in 2018 (987,662 tons). The largest importer was again OKTA Oil Refinery AD Skopje with a share of 68.85%, followed by Lukoil Makedonija DOOEL – Skopje with 10.06%, Supertrejd Skopje with 7.19%, OM Petrol Skopje with 3.04%, and other traders with approximately 10% share in the overall import of oil derivatives for 2019 [5].

In 2019, the largest import was on diesel fuel, 63.82 % of the overall import, followed by the import of unleaded petrol types with 12.31%, the mazut (fuel oil) with 8.21 %, the propane – butane (TNG) with 6.67%, the extra light fuel (EL-1) with 3.95%, the jet fuel with 5.04%, and a rather small percentage of biofuel import (Figure 9.20).

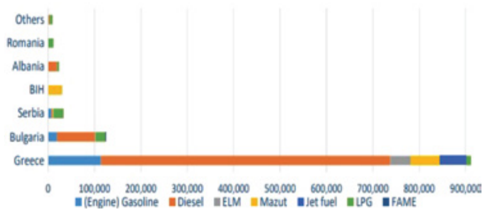
Figure 9.20 **Oil derivatives import in North Macedonia for 2017, 2018, and 2019 (tons/annually)**

Source: Energy and Water Services Regulatory Commission of The Republic of North Macedonia

Figure 9.20 indicates that the import of oil derivatives in 2019 records significant increase in relation with the previous two years. The increase of the petrol imported quantities was by 24.5% higher in relation to 2018, while the diesel fuels import in 2019 increased by 11.9% compared with the previous 2018. Significant growth, in 2019, by even 41.8% was recorded in the import of mazut fuel oil, while the TNG increased by 4.5%.

During 2019, in the Republic of North Macedonia, the import of oil derivatives by wholesale traders with crude oil, oil derivatives, biofuels and transportation fuels was made from 13 countries, whereby, largest quantities of oil derivatives were imported from the neighboring countries, such as Greece with 79.75%, Bulgaria with 10.82%, Serbia with 2.91 %, Bosnia and Herzegovina with 2.60 %, Albania with 2.06 %, Romania with 1.02 %, and a rather small percentage of import from other countries (Figure 9.21).

Figure 9.21 **Certain oil derivatives Import, according to countries, in 2019 (tons)**

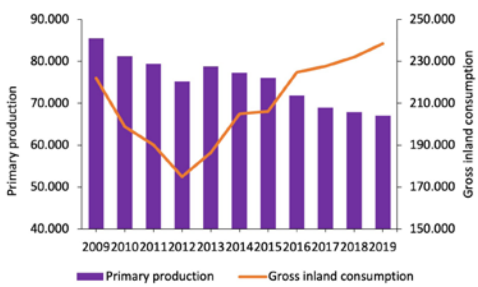


Source: Energy and Water Services Regulatory Commission of The Republic of North Macedonia

Romania

Primary crude oil production decreased by 25.6% over the period 2009-2019, whereas gross inland production increased by 7.4% over the same period (Figure 9.22). In 2019, crude oil production amounted to 67,040 barrels/day and gross inland consumption to 238,447 barrels/day.

Figure 9.22 **Evolution of crude oil production and gross inland consumption in Romania (barrels/day)**



Source: Eurostat

Between 2005 and 2017, oil and petroleum products accounted for 30% (on average) of final energy consumption – the largest share of all energy sources. While overall energy imports went down by 26% from 2005 until 2017, the share of crude and petroleum products in energy imports doubled during this period (from 35%

in 2005 to 76% in 2017). The downward trend in energy imports is likely to continue as a result of energy efficiency measures. At the same time, as Romania exhausts its domestic oil reserves without improving its reserve replacement, the import of crude and petroleum products is likely to go up. Refining products available for final consumption (energy and non-energy consumption) in Romania in 2019, presented a 5.3% increase compared to 2018 (Table 9.7).

Table 9.7 **Refining products consumption in Romania**

Refining products	Quantities (ktoe)	
	2019	**2018**
Refining gas	432.4	254.5
Liquified petroleum gases	487.7	516.2
Motor gasoline (excluding biofuel portion)	1,435.1	1,430.8
Aviation gasoline	1.6	1.0
Kerosene type jet fuel (excluding biofuel portion)	63.4	55.1
Other kerosene	1.3	1.9
Naphtha	1.6	1.6
Gas oil and diesel oil (excluding biofuel portion)	5,758.6	5,661.3
Fuel oil	5.2	-2.5
White spirit and special boiling point industrial spirits	12.7	11.4
Lubricants	101.2	93.7
Bitumen	552.2	393.7
Petroleum coke	455	455.4
Parafin waxes	8.2	6.1
Other oil products	21.5	-14.2

Source: Eurostat Energy Balances

Serbia

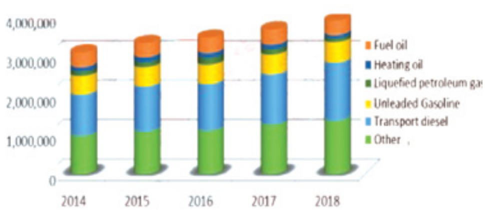
The necessary amount of processed crude oil is provided from import (over 70%) and a smaller part from domestic production from 63 oil fields and about 666 oil production wells. Domestic production of crude oil is decreasing in 2017, while simultaneously deficient quantities are provided by an increase in imports, which in 2017 amounted to 2,449,113 tonnes. In 2018, the production retains a slight downward trend, but the import volume increases to a value of 2,693,926. The energy balance for 2019 predicts a slight increase (1.5%) or 890,000 tons of production. [6].

Figure 9.23 **Review of production and import of crude oil (in tonnes) in Serbia**

Source: Republic of Serbia

Figure 9.23 demonstrates that domestic production of crude oil was decreasing in 2017, while simultaneously deficient quantities are provided by an increase in imports, which in 2017 amounted to 2,449,113 tonnes. In 2018, the production retains a slight downward trend, but the import volume increases to a value of 2,693,926. The energy balance for 2019 predicts a slight increase (1.5%) or 890,000 tons of production. The supply of petroleum products is carried out from import and from domestic processing of crude oil, obtained from the Pančevo Oil Refinery. The quantities of produced derivatives in 2018 amounted to 3,885,334 tonnes, which represents an increase of 6.14% with respect to 2017. Pančevo Oil Refinery in 2017 decreased the production of liquefied petroleum gas by 23.3% compared to 2016, while in 2018 there was a decrease of 35.1% (Figure 9.24).

Figure 9.24 **Production of petroleum products – comparative review of 2014 to 2018**

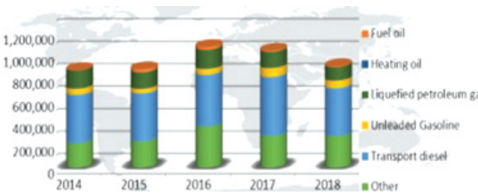


Production of petroleum products (in tonnes)	2014	2015	2016	2017	2018
Transport Diesel	1,047,495	1,142,290	1,182,882	1,273,116	1,469,062
Unleaded Gasoline	464,115	484,090	482,068	498,624	515,702
Liquide petroleum gas	108,986	121,117	165,768	127,210	82,555
Heating oil	124,999	136,723	138,514	128,275	102,948
Fuel oil	365,944	355,142	388,871	379,519	360,515
Other products	967,266	1,078,359	1,101,009	1,253,845	1,345,552

Source: Republic of Serbia

In 2017, the trend of import is stagnant (Figure 9.25), and the imported amount of derivatives was 1,039,632 tonnes, while in 2018 it is at a lower level and amounts to 932,450 tonnes. Motor fuels in 2017 registered an increase in imports of about 10%, while in 2018, there was an decrease of about 13.7%. Analyzing the structure of imported derivatives, it results that the highest amount of imported products is the amount of euro diesel imported mostly from Hungary, Bulgaria and Romania. The gasoline has been imported from Hungary, Austria and Romania [6].

Figure 9.25 **The import of petroleum products (in tonnes) – comparative review of 2014 to 2018**

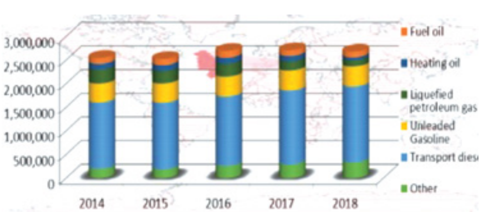


Import of petroleum products (in tonnes)	2014	2015	2016	2017	2018
Transport Diesel	432,832	429,627	460,612	526,685	458,085
Unleaded Gasoline	53,084	39,168	50,924	78,457	68,462
Liquide petroleum gas	160,635	146,665	170,261	143,933	119,947
Heating oil	1,260	36	0	122	591
Fuel oil	3,156	28,191	24,810	9,071	6,610
Other products	216,261	232,037	366,352	281,364	278,755
Total	867,228	875,724	1,072,959	1,039,632	932,450

Source: Republic of Serbia

Final consumption for energy purposes for 2017 (Figure 9.26) was at the level of 2,703,729 tonnes (an increase of 0.5% compared to 2016), while in 2018, it increased by 1.6% and amounted to 2,733,905 tonnes. In the structure of final consumption of derivatives for 2018, the industry participates with 13%, traffic from 77%, and other sectors with 10%.

Figure 9.26 **Consumption of petroleum products (in tonnes) - Comparative review for the period 2014 – 2018**



Consumption of petroleum products (in tonnes)	2014	2015	2016	2017	2018
Transport Diesel	1,408,752	1,416,856	1,474,142	1,571,130	1,643,371
Unleaded Gasoline	395,298	401,172	415,720	419,822	421,808
Liquide petroleum gas	295,413	259,989	269,114	187,168	124,080
Heating oil	123,634	130,287	135,238	122,571	102,514
Fuel oil	122,784	126,962	141,238	116,868	112,804
Other products	196,154	183,014	256,278	286,170	329,328
Total	2,542,035	2,518,280	2,691,730	2,703,729	2,733,905

Source: Republic of Serbia

Slovenia

Slovenia maintained a small production of crude oil. In 2018 it amounted to 0.379 ktoe, while there was no production of petroleum products. In 2018 primary supply with imported petroleum products amounted to 2.352 Mtoe, recording an increase of 0.4% compared to 2017. The highest level of consumption was achieved in 2008 with 2.879 Mtoe. The first data for 2019 is indicating a slow decrease in consumption. The most important petroleum product in Slovenia is diesel oil with a 62% share, mainly used in transport, followed by motor gasoline with 17% share, also mainly used in the transport sector (Figure 9.27). Transport is by far the highest user of petroleum products in Slovenia.

Figure 9.27 **Structure of oil demand in Slovenia for year 2018**

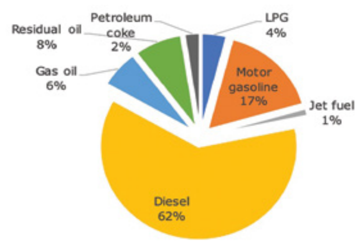


Table 9.8 **Key oil data for Slovenia**

(Mtoe)	2000	2008	2010	2015	2018
Production	0.098	0.000	0.000	0.000	0.001
Demand	2.392	2.879	2.458	2.209	2.352
Motor gasoline	0.809	0.679	0.593	0.443	0.431
Gas/diesel oil	1.172	1.967	1.695	1.591	1.719
Residual oil	0.120	0.016	0.009	0.003	0.000
Others	0.291	0.217	0.162	0.172	0.202
% Net import	2.332	2.995	2.491	2.261	2.548
Import dependency	97%	104%	101%	102%	108%
Share in TPES	37%	38%	34%	34%	34%

Turkey

Crude oil production in Turkey reached 62,297 barrels/day in 2019, representing a 31% increase compared to 2009. Gross inland consumption peaked in 2019 to almost 710,000 barrels/day, indicating a 115% increase compared to 2009 (Figure 9.28).

Figure 9.28 **Evolution of Crude oil production and gross inland consumption in Turkey (barrels/day)**

Source: Eurostat

Key characteristics of the Turkish oil market are presented below [7].

Refinery Production in 2019 compared to 2018:

- Total refinery petroleum products production increased by 38.84% to 34712676.927 tonnes.
- Diesel types production increased by 46.84% to 13642113.671 tonnes.
- Gasoline production increased by 12.89% to 5287867.933 tonnes.
- Aviation fuels production increased by 24.62% to 5964837.849 tonnes.
- Marine fuels production increased by 32.81% to 2345459.557 tonnes.
- Other production decreased by 6.44% to 7117493.604 tonnes.

Imports in 2019 compared to 2018:

- Total imports of petroleum products increased by 17.99% to 44822756.254 tonnes.
- Crude oil imports increased by 53.70% to 31073819.090 tonnes.
- Import of diesel types decreased by 8.67% to 10901420.042 tonnes.
- Import of fuel oil increased by 0.55% to 556581.360 tonnes.
- Import of aviation fuels decreased by 26.46% to 354256.256 tonnes.
- Import of other product decreased by 35.90% to 1906156.475 tonnes.

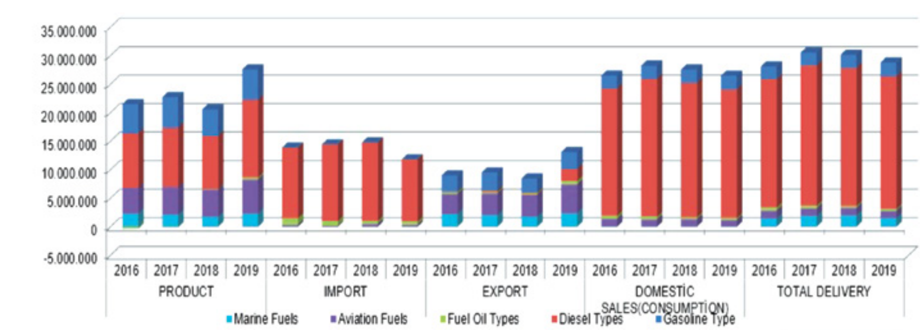
Exports in 2019 compared to 2018:

- Total exports of petroleum products increased by 60.92% to 14281813.497 tonnes.
- Exports of gasoline types increased by 21.83% to 2972490.236 tonnes.
- Exports of diesel types increased to 2121842.787 tonnes.
- Export of aviation fuels increased by 30.50 % to 5056892.940 tonnes.

Domestic sales in 2019 compared to 2018:

- Total petroleum product sales decreased by 3.85% to 26737749.895 tonnes.
- Gasoline sales increased by 2.98% to 2399341.118 tonnes.
- Diesel type sales decreased by 4.42 % to 22535057.252 tonnes.

Figure 9.29 **General overview of the petroleum market in Turkey**



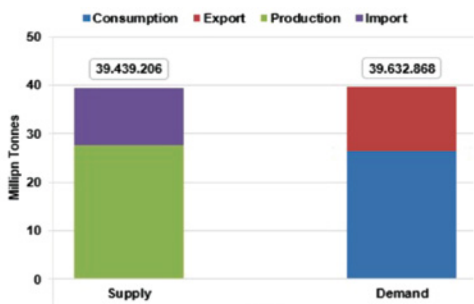
Source: Republic of Turkey -Energy Market Regulatory Authority

Table 9.9 **General overview of the petroleum market in Turkey (2019)**

PRODUCTION TYPE	PRODUCTION	IMPORT		EXPORT		DOMESTİC SALES(PRODUCTION)			TOTAL SUPPLY (Refinery Production + Import)	TOTAL DEMAND (Domestic Sales + Export)
		Refinery Import	Distributor and BDLH[1] Import	Distributor and BDLH[1] Export	Distributor and BDLH[1] Export	Refinery Sales[2]	Distributor Sales[3]	Distributor and BDLH[1] Bunker Sales[4]		
Gasoline Types	5.287.867,933	0,000	0,000	2.972.490,236	0,000	2.664,173	2.395.762,898	914,047	5.287.867,933	5.371.831,354
Diesel Types	13.642.113,671	466.846,714	10.434.573,328	1.277.477,872	844.364,915	0,000	22.109.206,204	425.901,853	24.543.533,713	24.656.950,843
Fuel Oil Types	356.146,340	487.101,601	69.479,759	392.804,409	192.706,016	76.829,181	271.610,958	0,000	912.727,700	933.950,564
Aviation Fuels	5.964.837,849	0,000	354.256,256	721.649,955	4.335.242,985	151.524,575	0,000	1.024.531,380	6.319.094,105	6.232.948,896
Marine Fuels	2.345.459,557	0,000	30.523,031	1.521.287,079	875.659,713	0,000	0,000	40.298,560	2.375.982,588	2.437.245,352
Total	**27.596.425,350**	**953.948,315**	**10.888.832,374**	**6.885.709,551**	**6.247.973,629**	**231.017,929**	**24.776.580,061**	**1.491.645,840**	**39.439.206,039**	**39.632.927,010**

Source: Republic of Turkey -Energy Market Regulatory Authority

Figure 9.30 **Supply and demand equilibrium in 2019 (tonnes)**



Source: Republic of Turkey -Energy Market Regulatory Authority

The total final consumption of oil increased from 33.425 Mtoe in 2013 to 41.681 Mtoe in 2018 by 24.7% (Table 9.10). This is mainly due to the increased consumption in the transportation sector; the industry substituted part of its oil demand by using natural gas.

Table 9.10 **Sectoral breakdown of total final consumption of oil in 2013 and 2018**

	2013		2018	
Sector	Mtoe	%	Mtoe	%
Industry	3.961	12	3.767	9
Transport	20.307	61	27.825	67
Other	9.017	27	9.734	24
Total Oil	33.425	100	41.681	100

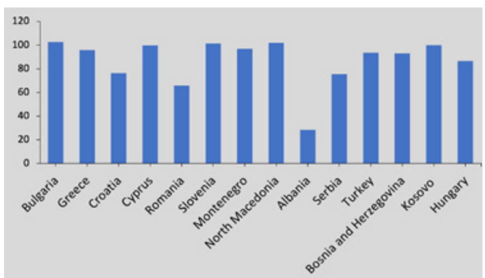
Source: Ministry of Energy and Natural Resources, 2019

9.1.3 Oil import dependency

In 2019, the EU-28 relied on net imports for 88.5% of its oil consumption. This ratio is one percentage point below the peak of 89.5% recorded in 2015.

The country in the region with the highest oil import dependency rate in 2019, was Bulgaria (102.6%). At the other end of the scale, Albania relied on net imports (imports minus exports) for 28.3% of oil and petroleum products consumed in 2019. Greece had an oil import dependency of 95.7%. All countries in SE Europe show a large dependency on net oil imports, with an average oil dependency rate of 87% in 2019 (Figure 9.31).

Figure 9.31 **Oil import dependency in SE Europe in 2019 (%)**



Source: Eurostat

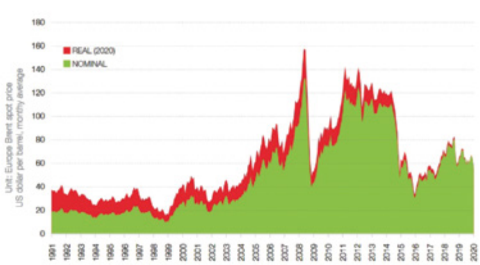
Another indicator reflecting how much an economy is dependent on oil, is the oil intensity of GDP, defined as the volume of oil consumed per euro of GDP. There is a large variation in the oil intensity of EU Member State economies, with Cyprus and Bulgaria the most oil-intensive Member States. In all EU Member States, the oil intensity of GDP has declined over recent decades, because of energy efficiency improvements, partly in response to policy efforts such as the introduction of vehicle emissions standards [8].

9.1.4 Oil prices

The price of oil is an important marker for the global economy and is closely watched by businesses and policy-makers. The major benchmarks are priced in US dollars. After a decade of relatively low prices, oil started rising last decade, leading to peaks just before the financial crisis in 2008. Since the beginning of 2020, oil prices started falling again amid the COVID-19 crisis and a price war led by Riyadh and Moscow [9].

Over the last 30 years or so we have seen severe episodes of crude oil price volatility (Figure 9.32). Crude oil started rising in early 2003, supported by strong geopolitical factors and uncertainty over continuing production from the Middle East. Then, in an effort to address rapidly rising of USA and Canadian production, on the strength of shale oil, Saudi Arabia led OPEC flooded the global market and resulted in the oil price crash (2014). It took almost 3 years for prices to recover driven by global demand, geopolitical tensions and OPEC output cuts, before settling in 2019 (at around 60-70 USD/barrel) amid a slowing global economy and increasing US shale oil output. In 2020, prices plummeted amid sharp demand decreases and mobility restrictions resulting from the COVID-19 pandemic, until mid-April 2020, when major oil producers agreed to cut production. Prices have been on the rise since, and may continue to grow alongside increases in global economic activity (Figure 9.33) [10], [11]. As the publication was going to press (September 2021) oil prices had made substantial gains trading steadily above 80 dollars per barrel.

Figure 9.32 **Crude oil price evolution**



Source: Fuels Europe

Figure 9.33 **Brent Crude Oil prices over 5 years (USD/barrel)**

Source: FT

Figure 9.34 **WTI Crude Oil prices over 5 years (USD/barrel)**

Source: FT

Figure 9.35 **Crude oil (Brent) and European wholesale gasoline, diesel and heating oil prices (eur/litre)**

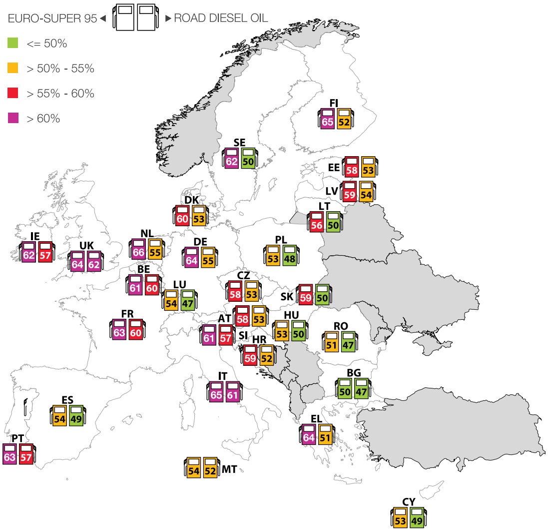
Source: European Commission

Wholesale prices for oil products are mainly driven by the ups and downs in crude oil prices. However, other factors, like the specific oil product supply-demand balance, refinery maintenance and seasonality prevailing margins, had also some influence on them. In Europe, retail prices rose since 2016, reaching their highest levels since 2012 and 2013 in 2018 and 2019. In the period 2016-2019, in nominal terms, gasoline prices increased by 12% (annual average growth of 3%), diesel by 17% (annual average growth of 4.3%), and heating oil by 20.3% (annual average growth of 5.1%) due to rising oil/wholesale prices and to a lesser extent to excise taxes. All prices evolved in a similar way, fluctuating alongside crude oil prices, but to a much lesser extent. The high share of taxes (excises plus VAT), as applied across Europe, including SE Europe countries, which may account for up to 70% of the price, restricts prices at the pump from the variability of crude oil prices and exchange rates as oil is still traded in US dollars only [10]. In Europe the price at the pump is driven to a large degree by tariffs and taxes (Map 9.1). On average, over half the cost of fuel at the pump represents taxes. The taxes on gasoline are generally higher than for diesel. This differential tax treatment has driven the demand shift over the past 20 years. Fuel taxes in the EU contribute substantially to Member States' revenues [9].

Map 9.1 **Total taxation share in the end consumer price**

EURO-SUPER 95

COUNTRY	%
Netherlands	66
Finland	65
Italy	65
Germany	64
Greece	64
United Kingdom	64
France	63
Portugal	63
Ireland	62
Sweden	62
Belgium	61
Slovenia	61
Denmark	60
Croatia	59
Latvia	59
Slovakia	59
Austria	58
Czechia	58
Estonia	58
Lithuania	56
Luxembourg	54
Malta	54
Spain	54
Cyprus	53
Hungary	53
Poland	53
Romania	51
Bulgaria	50



ROAD DIESEL OIL

COUNTRY	%
United Kingdom	62
Italy	61
France	60
Belgium	60
Ireland	57
Portugal	57
Slovenia	57
Germany	55
Netherlands	55
Latvia	54
Austria	53
Czechia	53
Denmark	53
Estonia	53
Croatia	52
Finland	52
Malta	52
Greece	51
Lithuania	50
Slovakia	50
Hungary	50
Sweden	50
Cyprus	49
Spain	49
Poland	48
Bulgaria	47
Luxembourg	47
Romania	47

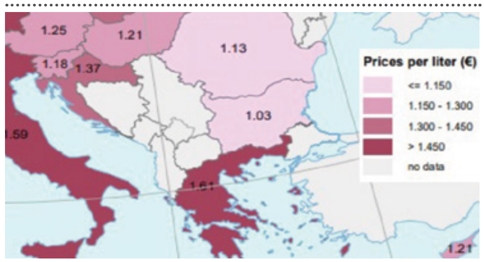
Source: Fuels Europe

In most EU Member States, gasoline prices are generally higher than diesel prices due to the higher tax element. Only a fraction of the price paid at the pump contributes to the refiner's income, the remainder going to Member States and the purchasing of the crude oil. In SE Europe, oil prices are displayed in Map 9.2 and Map 9.3 [12], [13].

Map 9.2 **Consumer prices of Automotive Gas Oil (Diesel Oil) on May 10, 2021**

Source: European Commission

Map 9.3 **Consumer prices of Euro-Super 95 on May 10, 2021**



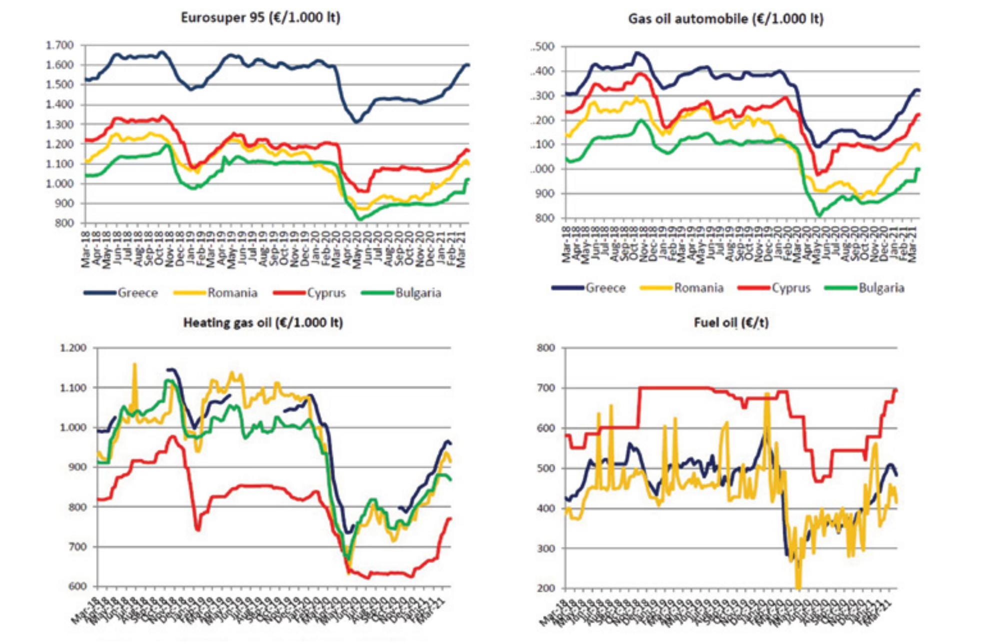
Source: European Commission

Retail fuel prices vary substantially across the EU-27, mainly due to differences in national taxation rates. The price of Eurosuper 95 (gasoline) in Greece stood at €1.601 per liter on March 22, 2021 – higher than the EU-27 average at €1.448,17/lt and the country's highest price in March. The price of Eurosuper 95 in Romania stood at €1.118,42/lt on March 22, substantially lower than the EU-27 average, but it was the country's highest price in March. Similarly, the price of Eurosuper 95 in Bulgaria stood at €1.021,88/lt on March 29 – also significantly lower than the EU-27 average at €1.446,09/lt and again the country's highest price in March (Figure 9.36) [14].

In terms of gas oil automobile (diesel), the price in Greece stood at €1.324/lt on March 22, 2021, slightly higher than the EU-27 average at €1.301,48/lt and it was the country's highest price in March. Romania's gas oil automobile price was at €1.103,93/lt on March 22, substantially lower than the EU-27 average, but it was the country's highest price in March. Moreover, the price of gas oil automobile in Bulgaria stood at €1.000/lt on March 22, also significantly lower than the EU-27 average, but it was again the country's highest price in March (Figure 9.36) [14].

Relatively high prices are also imposed on non-EU Member States of SEE as Table 9.11 shows. The exception being Turkey, which traditionally has low oil related taxes.

Figure 9.36 **Oil product prices: Greece, Romania, Cyprus**



Source: IENE Market fundamentals and prices March-April 2021

Table 9.11 **Fuel Prices in selected countries on April 26, 2021**

Country	Unleaded 95 RON- Gasoline (€/lt)	Gas Oil Automobile – Diesel (€/lt)	Heating Gas Oil (€/lt)
Bulgaria	1.032	1.004	0.869
Croatia	1.371	1.295	0.613
Cyprus	1.210	1.229	0.773
Greece	1.600	1.317	0.957
Hungary	1.169	1.160	1.160
Romania	1.117	1.089	0.864
Slovakia	1.353	1.174	-
Slovenia	1.172	1.190	0.956

Source: ec.europa.eu

On June 7, 2021, the average price of diesel in SEE was 0.86 euro per liter and the average price of gasoline stood at 0.97 euro per liter. However, there is a substantial difference in these prices among countries. As a general rule, richer countries have higher prices while poorer countries and the countries that produce and export oil have significantly lower prices. One notable exception is the U.S. which is an economically advanced country but enjoys low gas prices because of the low taxes applied to oil products. The differences in prices across countries are due to the various taxes and subsidies for diesel/gasoline. All countries have access to the same petroleum prices in the international markets but then each decide to impose different taxes. As a result, the retail price of diesel/gasoline is different. Table 9.12 shows retail (pump) level prices, including all taxes and fees in different countries in SE Europe[15].

Table 9.12 **Consumer prices (€/L) of petroleum products by SE Europe country on June 7, 2021**

Countries	Gasoline	Diesel	Heating oil
Albania	1.176	1.136	-
Bosnia and Herzegovina	1.077	1.038	-
Bulgaria	1.039	1.017	0.868
Croatia	1.349	1.334	0.653
Greece	1.613	1.334	0.959
Cyprus	1.229	1.248	0.777
Hungary	1.230	1.235	1.228
Israel	1.603	1.523	-
Montenegro	1.310	1.160	1.140
North Macedonia	1.105	1.197	0.975
Romania	1.125	1.107	0.915
Serbia	1.311	1.345	-
Slovenia	1.191	1.243	0.994
Turkey	0.743	0.694	0.623

Source: Global Petrol Prices

For Retail Sector by country see Section 9.9.

9.1.5 Oil Infrastructure in SE Europe

Oil infrastructure in the SE European countries is extensive and form and integral part in each country's energy system. Without such infrastructure, the majority of fuel needed to light, heat, and cool homes and businesses and to power transportation and industry cannot be produced and delivered to markets and consumers. In this sense, infrastructure is the lifeblood of the oil and gas industry. Oil infrastructure in SEE encompasses a broad range of assets, including pipelines, drilling platforms, refineries, terminals, processing plants, and storage facilities, most of which are massive and expensive industrial complexes [16].

Pipelines are a long-established, safe and efficient mode of transport for crude oil and petroleum products. They are used both for short-distance transport (e.g. within a refinery or depot, or between neighbouring installations) and long distances. An extensive network of cross-country oil pipelines in Europe, as illustrated in Map 9.4, meets a large proportion of the need for transportation of petroleum products [9].

Map 9.4 **Oil pipelines – Map of Europe**

Source: Fuels Europe

A brief country by country account of oil related infrastructure in the SEE region follows.

Bosnia and Herzegovina

Imported crude oil is processed in two oil refineries. The first one is the "Rafinerija nafte Brod"* and is used for petroleum processing and production of petroleum products (gasoline, diesel, bitumen, LPG, fuel oil, sulphur) and the second one is the "Rafinerija ulja Modriča", which produces motor oil and various special purpose oils for the industry and other commercial purposes.

Bulgaria

The main oil refinery in Bulgaria and one of the biggest in the Balkan peninsula is owned and operated by Lukoil Neftochim Burgas AD and is located in Burgas. Oil is imported through Bulgaria's main port at Burgas, where both the oil terminal and refinery are connected by pipeline to several Bulgarian cities. Physical storage and movement of fuel from the refinery and importers to the retail market and to end-users, is curried out through large scale storage infrastructure and including transportation via pipelines and tracks. Lukoil is the sole company which owns and operates all pipelines, serving the geographical area from Burgas to Sofia with a branch to Asparuhovo, Varna. The pipeline is intended for the fuel supply of the domestic market only and is not connected to the neighbouring countries. In addition to the pipeline, the logistics system of Lukoil Bulgaria EOOD includes a well-developed transport system for the wholesale supply of fuels through the use of railway transport, covering the territory of the country and even distribution to warehouses and infrastructure for retail sales in key cities. Thus the physical flow of fuel throughout the country is achieved.

Bulgaria's plan to participate in projects for the construction of crude oil pipelines such as the Burgas-Alexandroupolis and AMBO have dragged in time. In December 2011, the Bulgarian government withdrew from the Burgas-Alexandroplis project as a result of protests and a local referendum, on environmental grounds. The development of the second project - AMBO - was also suspended. The failure of these two projects is likely to reduce the country's ability to access alternative sources of crude oil over the coming years. The availability of an oil processing infrastructure and the country's ability to transport and distribute petroleum products in stable volumes, as well as the large investments in its expansion and modernization, offer grounds for optimism both in terms of security and future market development. This forecast is further supported by the current full liberalization of the oil market, ensuring the free movement of energy flows and products. The transport sector, especially road transport, in Bulgaria is responsible for almost the entire FEC of petroleum products. Considering the lack of policy on energy efficiency improvement in the transport sector, no change should be expected in oil demand trends for the foreseeable future.

Croatia

INA Group operates three oil refineries: Oil Refinery Rijeka (Urinj), Oil Refinery Sisak and Lube Refinery Zagreb Ltd. The JANAF oil pipeline system is used for the imported crude oil and each transportation to regional oil refineries. It is owned and operated by JADRANSKI NAFTOVOD, Joint Stock Co. (JANAF Plc.), headquartered in Zagreb. The JANAF pipeline was constructed in 1979 as an international oil transportation system from the tanker and terminal port of Omišalj to domestic and foreign refineries in Eastern and Mid-Europe. The designed pipeline capacity amounts to 34 million tons of oil a year, and the installed one is 20 million tons. The storage capacity at the Omišalj, Sisak and Virje terminals amounts to 1 940 000 m3 for oil and 222 000 m^3 for oil products in Omišalj and Zagreb.

The JANAF oil pipeline system, consists of a reception and forwarding terminal at Omišalj on the island of Krk. A country wide pipeline system of total length of 631.3 kilometres has been developed, which includes the following branches: Omišalj-Sisak; Sisak-Virje (with a

* The refinery in Brod had a major incident 1-2 years ago that took it offline. So, currently, it is not in operation.

section to Lendava)-Gola (Croatian-Hungarian border); Sisak-Slavonski Brod (with asection to Bosanski Brod)-Sotin (Croatian-Serbianborder), Reception and forwarding terminals in Sisak, Virje and near Slavonski Brod, Omišalj-Urinj submarine pipeline, which connects terminal port of Omišalj on the island of Krk with the INA-Rijeka Oil Refinery on land, the island of Krk-mainland section in the total length of 5.05 km, with the submarine section of 730 meters, as a part of Omišalj-Sisak section.

Map 9.5 **The JANAF System**

Source: JANAF

Reconstruction, upgrading, maintenance and capacity increase of the existing JANAF and Adria pipelines linking the Croatian Omisalj seaport to the Southern Druzhba (Croatia, Hungary, Slovak Republic) aim at increasing capacity and operation and security of oil pipelines from Omisalj (HR) through Hungary to the Southern Druzhba pipeline in Slovakia.

Cyprus

Following a government decision of November 2014, the island's oil terminal has been relocated from Larnaca to the Vasilikos industrial area. The relocation of the oil products storage except LPG was completed in 2020 and that of LPG in 2021. The modern and upgraded larger oil storage facilities will help improve the security of supply, since larger quantities of petroleum products could be stored on the island as it will also be possible to unload larger tankers. Alongside with the abovementioned procedures, the Cyprus Organization for the Storage and Management of Oil Stocks (KODAP), is planning to build its own oil storage terminal in the Energy and Industrial Area of Vasilikos in order to relocate its own oil stocks which are held abroad and in private terminals in Cyprus, as well as, to reduce the annual storage cost. To this effect KODAP has signed a € 35 million financing agreement with the European Investment Bank (EIB) to finance the construction of a privately owned oil terminal. This terminal will be built at the Vasilikos Energy Center and will consist, at this stage, of six liquid fuel storage tanks with a total capacity of 200.000 cubic meters, pipelines and pumping stations, fire safety and protection systems, as well as buildings. Until the finalisation of design & construction of the new KODAP fuel farm, the stocks being held were transferred to the VTTV terminal, a private fuel tank farm. The new Fuel Farm will be situated on the north/east of the Vasilikos Cement Company, and it will consist of the following: Four tanks of CLASS A (Mogas) products, and seven tanks of CLASS B (Jet fuel, and Diesel) products will be erected, of total storage capacity of approximately 430.000 m^3. The tank sizes are identical and are of 45m in diameter and 22m height.

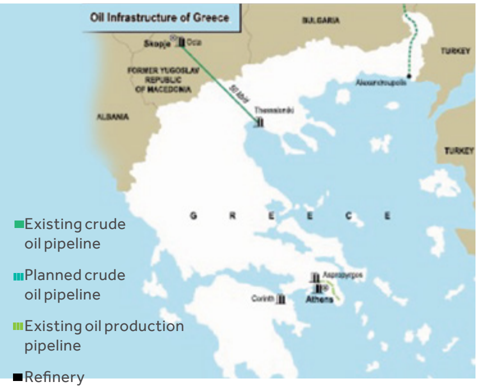
The oil products storage capacity in Cyprus, by owner, was formulated as follows:

- Electricity Authority of Cyprus: 207.000 cubic meters (gasoil and HFO)
- Electricity Authority of Cyprus (stocks of KODAP): 30.000 cubic meters (gasoil)
- Cyprus Petroleum Storage Company Ltd: 10.000 metric tonnes (bitumen)
- VTTV Ltd: 544.626 cubic meters (gasoil, gasoline, jet fuel, FAME)
- Petrolina Group: 104.139 cubic meters (gasoline, gasoil, kerosene, bunkering fuels, jet fuels, bitumen)
- Yugen Ltd: 69.000 cubic meters (gasoline, gasoil, kerosene, bunkering fuels).

Greece

Greece has two oil pipelines, only one of which is operational. The 53 km Aircraft Fuel Supply Pipeline links HELPE's Aspropyrgos refinery to Athens International Airport in Spata. It is operated by the Athens Airport Fuel Pipeline Company, which also financed and constructed the pipeline. With a capacity of 2.6 mcm per annum, it is considered sufficient to accommodate the potential growth of air traffic well into the future. The second one, a 210 km crude oil pipeline, which links Greece with North Macedonia, has not been in operation since 2013. Plans to build a pipeline to link Greece with Bulgaria to offer an alternative supply route for Russian and Caspian oil known as in the Burgas – Alexandroupolis pipeline, were abandoned in early 2011 and thus the intergovernmental agreement that had been signed in March 2007. Political supposedly environmental coordinators contributed to the project's cancellation. Most crude oil and products are moved by trucks and ships within Greece, while supplies to power plants are transported by ship and train. There are ten oil terminals in Greece, with a total loading capacity of 0.8 mcm per day and a total discharging capacity of 2.3 mcm per day. Seven of them are located in the Attica Area (including Athens) and three are in the Thessaloniki area. Six oil terminals (Aspropyrgos, Elefsina, Thessaloniki, Aghioi Theodori, Pachi, and Agia Triada) receive crude oil and four of these are located near refineries. The country's total crude oil discharging capacity is around 1.6 mcm per day. Imported crude oil is refined into oil products at four domestic refineries. The three refineries that belong to HELPE (Hellenic Petroleum S.A.) are located in Aspropyrgos, Elefsina and Thessaloniki and represent approximately 65% of the country's total refining capacity, with crude oil and oil product storage tanks having a total capacity of 6.65 million cubic metres. The refinery of Motor Oil at Agioi Theodoroi near Corinth produces the rest.

Map 9.6 **Oil infrastructure of Greece**



Source: IEA [17]

Kosovo

Kosovo does not possess any pipelines for crude oil or for oil products transportation. Oil products are imported 75% by road transportation and 25% by railroad. There are 12 storage facilities that are licensed for fuel wholesale (diesel, petrol, LPG).

Montenegro

The storage of petroleum products and LPG in Montenegro (2018) is being undertaken by 32 entities, of which 22 performed both activities. The storage of petroleum only products was undertaken by seven entities, while only three entities involved in LPG storage. Total storage capacities corresponding to petroleum products at the end of 2018 amounted to 142,327 m³, of which gazoline product storage capacities corresponded to 138,959 m³, while LPG storage capacities amounted to 3,368 m³. In 2018, the storage capacity was increased by 656 m³ (632m3 gazoline products and 24m3 petroleum gas).

Of a total storage capacity of 142,327 m³, some 126,292 m³ belong to Jugopetrol AD, of which its Bar Installation is 110,170 m³, petrol stations between them have 6.895 m³, aviation services in Podgorica and Tivat share to 9,040 m³, while three yachting services, in Budva, Herceg Novi and Kotor, share 187 m³ of a storage facility. Some the 16,035 m³ of storage capacity belong to other energy entities, which undertake the storage of petroleum products and LPG in gas stations and yachting services. The energy entity with the highest storage capacity for LPG is Montenegro is Bonus DOO Cetinje, with a total capacity of 1,100 m².

North Macedonia

The energy infrastructure of the oil sector in the Republic of North Macedonia (Map 9.7) enables import, export and transportation of crude oil and oil derivatives, crude oil processing, biofuel production, distribution, transportation and oil derivatives sale. In 2002, the Thessaloniki – Skopje oil pipeline commenced its operations with a length of approximately 213,5 km, 16-inch NPS, with a transport capacity of 2,5 million tons of oil on annual level. The transportation of crude oil starts from the HELPE Industry Complex in Thessaloniki and ends at OKTA Terminal in Skopje. The route of the oil pipeline runs between the terminals of the HELPE and OKTA and includes 15 block ventilation stations (three located within Greece, and 12 located in the Republic of North Macedonia) [5]. The oil pipeline is managed by the Joint Macedonian – Greek Enterprise VARDAX, with Headquarters in Thessaloniki, and an Office in Skopje, but the pipeline is currently idle awaiting approvals and technical upgrade to be used for diesel [2].

Map 9.7 **Energy infrastructure in the oil sector in North Macedonia**

Source: Energy and Water Services Regulatory Commission of the Republic of North Macedonia [5]

The total storage capacity for oil and petroleum products in North Macedonia is approximately 382,000 m^3.

Romania

Romania's crude pipeline system is concentrated almost entirely in the central-southern part (Constanta, Bucharest, the outer Carpathian region). The main gateway for crude import is Constanta. The oil transport system is not connected to any of the neighboring countries and has mostly a domestic purpose. Conpet is the operator of the oil transport system (also referred to as "crude oil, rich gas, condensate and ethane pipeline transport system"). For areas not connected to the transport system, Conpet uses railway tanks.
The National Transport System (Map 9.8) [18] was built to transport crude from the oil fields to the refineries. The system consists of 3,800 km of pipelines, out of which 3,161 km are currently used. The system has the following subsystems, grouped according to the transported products:

- **Domestic crude and condensate transport subsystem** (approx. 1,540 km) transports crude oil and condensate produced in OMV Petrom areas to the refineries. The domestic crude oil and condensate production is transported via pipelines, by railway tanks, or combined (rail and pipelines).

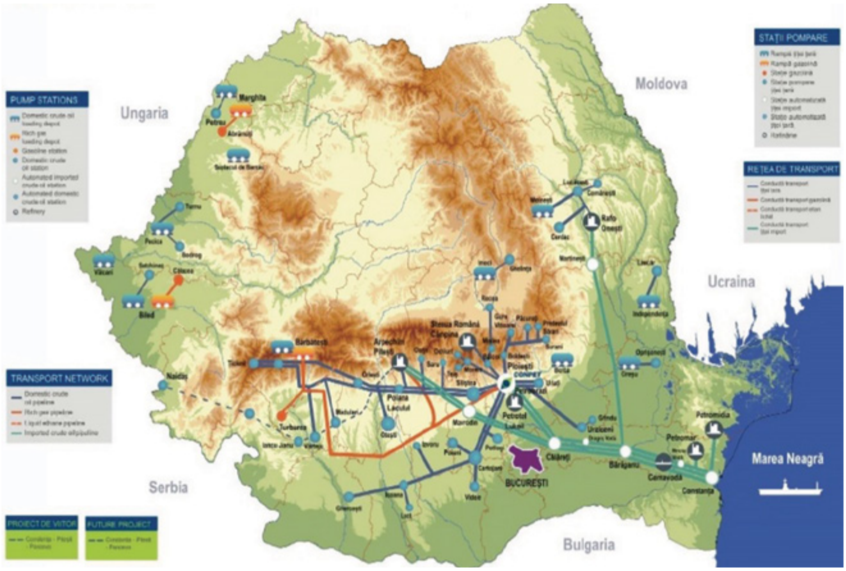
- **Rich gas transport subsystem** transports rich gas from the separation units in Ardeal (Biled and Pecica) to the Petrobrazi refinery.

- **Ethane transport subsystem** from the Turburea ethane separation platform to the Arpechim Pitesti refinery. Currently, due to the shutdown of Arpechim refinery, the subsystem is not used, except for one portion of the pipeline which is used to transport condensate from Totea warehouse to Petrobrazi refinery.

- **Subsystem for crude imports** transports crude oil from Oil Terminal Constanta to the refineries in Ploiești, Arpechim-Pitești and Midia

[2] HELPE 2020 Annual Financial Report, p. (42) / (82). The pipeline has not been operational since 2013 and is expected to commence operation during January 2022. Source: HELPE

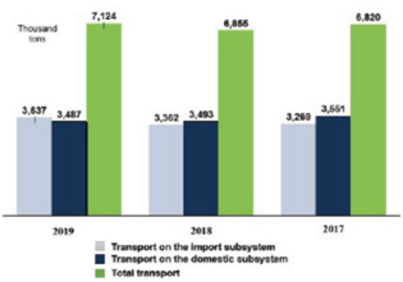
Map 9.8 **National oil transport system**



Source: Conpet

Oil transport is a natural monopoly activity of Conpet. The total annual volume transported through the oil pipeline system is 7 million tons, which translates into a transport throughput utilization rate of 40% (Figure 9.37).

Figure 9.37 **Oil volumes transported by Conpet**



Source: Conpet

Table 9.13 **Crude oil transport infrastructure in Romania**

Domestic Crude Oil	Imported Crude Oil	Rich Gas and Ethane	Crude Oil and Rich Gas
1,540 km of pipelines	1,348 km of pipelines	921 km of pipelines	13 loading ramps
6,9 million tons per year throughput	20,2 million tons per year throughput	0,33 million tons per year throughput	2 unloading ramps
126,000 mc storage capacity	45,000 mc storage capacity	663 mc storage capacity	13 locomotives and 69 railway tanks

Source: Conpet [18]

Serbia

Transnafta pipleline supplies the Novi Sad and Pančevo oil refineries with crude oil. The pipeline with a total length of 154 km stretches from the Croatian border on the Danube river through Novi Sad and Pančevo. This pipeline links with the JANAF system, which departs from the port of Omišalj on the island of Krk in Croatia and across the Sisak Refinery. The first block station is in Bačko Novo Selo, and the pipeline (via terminals PE Transnafta at Novi Sad Oil Refinery) extends until the Pančevo Oil Refinery (via measuring station of PE Transnafta). The imported crude oil is transported through all stations along the route, from Novi Sad to Pančevo. The pipeline infrastructure consists of a terminal in Novi Sad with a storage capacity of 2x10,000 m3 and a pumping station, eight block stations along the pipeline, a measuring station with Pančevo Oil Refinery, cathodic protection system and supervisory control system of oil pipelines [6].

A network of crude oil pipeline of approximately 169 km is in operation linking the "kikinda Oil Field" with the Novi Sad oil refinery and delivery station at Elemir and Nadrljan. A petrochemical product pipeline is in operation and runs between Petrochemical complex and the Pančevo Oil Refinery. This product pipeline transports ethylene and propylene to the Romanian border and further to Solventum in Romania. The total length of the pipeline is about 65 km in the Republic of Serbia and about 50 km through Romania and it consists of two parallel product pipelines: Ethylene with a diameter of 168.3 mm and Propylene with a diameter of 114.3 mm.

Crude oil storage tanks are located along the route of the crude oil pipelines, more precisely at terminals of PE Transnafta in Novi Sad and at the Terminal Novi Sad within the Novi Sad Oil Refinery and Pančevo Oil Refinery owned by NIS JSC. PE Transnafta Terminal has four tanks for crude oil, of 10,000 m3 each. NIS JSC at the Terminal in Novi Sad Oil Refinery has storage tanks with a capacity of cca 140,000 m3 for the storage of crude oil. All tanks have been renovated over the last three years. More storage tanks are to be found at the dispatching stations Kikinda Field, Tisa and Nadrljan there are storage tanks in the function of local transport of crude oil in the capacity of over 70,000 m3 [44][40]. In the Pančevo Oil Refinery there are storage tanks for technological processes with a total capacity of about 700,000 m3 [6]. In 2018 there were in force a total of 21 licenses for storage of crude oil, petroleum products and biofuels. Among the companies which manage of licensed storage tanks for the storage of crude oil and petroleum products, the largest capacities belongs to NIS JSC (100,000 m3). It is followed by PE Transnafta, Naftachem and Mitan oil. These four entities between them represented in total about 80% of the entire licensed storage capacity of Serbia.

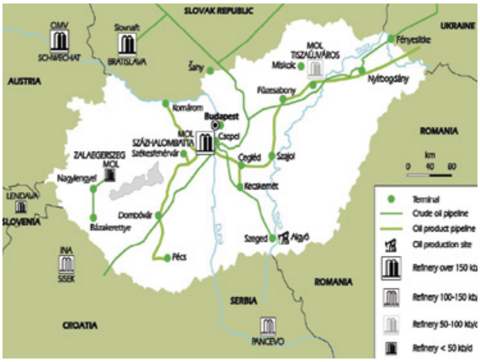
Hungary

There is one major refinery in Hungary, the Danube Refinery in Százhalombatta, with a capacity of 162 kb/d. There are also two smaller refineries in Tiszaújvaros (60 kb/d) and Zalaegerszeg (10 kb/d) which do not process crude oil at present. All three refineries are owned by the Hungarian Oil and Gas Company (MOL). The Duna refinery is operated as a hub in co-ordination with the MOL-owned 122 kb/d refinery in Bratislava (Slovak Republic) and a significant amount of intermediate products are exchanged between the two. According to the government, the critical minimum supply for the refinery is 77 kb/d, possibly less in a "stop and go" operation mode.As elsewhere in Europe, the region is struggling with refining overcapacity. The country's refined product output averaged 172.4 kb/d (the output figure is higher than the refinery's capacity as a result of the hub regime with the Bratislava refinery) [19].

Crude oil is supplied to Hungary through pipelines. The Southern Friendship (Druzhba) pipeline system, originating in Russia and transiting Belarus and Ukraine, is Hungary's main crude oil supply channel. The section of the older Druzhba I pipeline (built in 1961) between Százhalombatta and Sahy has recently been fully renovated and increased its capacity from 70 kb/d (3.5 Mt/year) to 120 kb/day (6.0 Mt/ear). It enables supplies to Hungary from its northern border with the Slovak Republic. The Druzhba II (built in 1971) has a capacity of 160 kb/d (7.9 Mt/year) and supplies Hungary from its eastern border with Ukraine. The pipeline terminates at the Duna refinery at Százhalombatta (via the Tisza refinery). Domestic oil production is transported via an internal pipeline between Algyő, where oil is produced, and the Százhalombatta refinery.

The Adria oil pipeline section between Sisek and Százhalombatta has recently undergone renovation and increased its capacity from 200 kb/d (10 Mt/yr) to 280 kb/d (14 Mt/yr), roughly equal to the total processing capacity of the Bratislava and Duna refineries combined. This pipeline links the Duna refinery to the Croatian port of Omišalj. This pipeline was originally intended for the delivery of crude oil imports from the Middle East or Africa to Hungary but was mainly used for transporting Russian crude oil in the opposite direction, transiting to the Sisek refinery in Croatia. In recent years, its use for transporting cargoes from Omišalj (the pipeline's original purpose) has increased. Hungary is also linked to the Eastern oil product pipeline that transports product from Russia's refining centers via Ukraine. This enables MOL to purchase gasoil feedstock from Russia for further processing. According to the IEA [19] total storage capacity in Hungary in 2015 was 3.1 mcm (19.5 mb): 1.1 mcm of this capacity is for crude oil storage and 1.9 mcm for product storage. There has been no substantial change since then.

Map 9.9 **Hungary's oil facilities**



Source:IEA

Turkey

As the IEA Turkey 2021 Energy Policy Review states, in January 2020 there were five refineries operating in Turkey with a total crude distillation capacity of 860 kb/d [20]. The Izmir, Izmit and STAR refineries are supplied with crude oil by sea tankers (as they are located in direct proximity of oil terminals). The Kirikkale refinery is supplied via a dedicated pipeline from Turkey's Mediterranean oil hub in Ceyhan. The Batman refinery processes crude from a number of smaller oil fields in Batman Province, delivered to the refinery both via an existing pipeline network and by road tankers. The STAR refinery, a USD 6.2 billion investment by State Oil Corporation of Azerbaijan (SOCAR), started operations in October 2018 and is the first newly built oil processing plant in the country since 1986. The refinery processed over 180 kb/d of crude in 2019, significantly helping to reduce Turkey's dependence on imported oil products, most notably diesel [20]. BOTAŞ and its affiliate BIL operate two domestic and two international crude oil pipelines in Turkey [21]:

- The oldest is the Batman-Dörtyol pipeline with 4.5 mill t/year capacity, running 511 km from the oilfields of southeast Turkey to the Mediterranean Terminal in Dörtyol. The Ceyhan-Kırıkkale pipeline with a capacity of 7.2 mil t/y since 1986 supplies the Kırıkkale refinery with crude oil in 2018. The pipeline transported 4.270 mil t and in 2019 some 4.766 mil t.
- The Iraq-Turkey crude oil pipeline was inaugurated in 1976 and the initial capacity of 35 mill t/year was increased in 1984 to 48.6 mill t. With the commissioning of a second line in 1987 the capacity reached 70.9 mill t/year. The pipelines run from the oil fields in Northern Iraq to the Mediterranean harbour of Ceyhan. Since the Gulf War in 1991 and the UN embargos in 1990's, these pipelines are used in reduced capacity and some sections are damaged. In 2018 the Iraq-Turkey pipeline transported 18.371 mil t and in 2019 some 26.478 mil t to Ceyhan Terminal.
- The 1776 km long BTC pipeline stretching from the Sangachal Terminal in the Caspian Sea in Azerbaijan via Georgia to Ceyhan Terminal in Turkey was inaugurated in 2006. The pipeline transports crude oil from ACG fields, condensates from Shah Deniz field and other crude from the Caspian basin. It has a capacity of 50 mil t/year and in 2018 supplied the Ceyhan Terminal with 34.894 mil t and in 2019 with 32.093 mil t.

Map 9.10 **Turkish oil infrastructure**

Source: IEA

Table 9.14 **Existing crude oil pipelines in Turkey**

	Length (km)			Capacity		Diameter (inch)	Pump Station	Storage Tanker
				million tonnes/year	million barrel/year			
Iraq-Turkey COP		Turkey	Total	70.9	553		6	12
	Line I	651	986			40		
	Line II	652	890			46		
	Total	1,303	1,876					
Ceyhan-Kırıkkale COP	448			7.2	51	24	2	3
Batman-Dörtyol COP	518			4.5	31.5	18	3	23
Bakü-Tiflis-Ceyhan COP*	Turkey	Total		50	365	34-42-46	4	7
	1,076	1,776						

Source: Botas [20]

Table 9.15 **Amounts of crude oil transported annually (thousand barrels) in Turkey**

	IRAQ-TURKEY COP	CEYHAN-KIRIKKALE COP	BATMAN-DÖRTYOL COP	BTC COP
2021*	47,019	7,154	5,772	51,998
2020	191,855	32,142	24,376	208,064
2019	194,084	34,938	21,536	235,243
2018	134,662	31,300	20,470	255,770
2017	184,927	39,292	19,757	252,763

*As of March
Source: Botas [20]

9.1.6 Oil Stocks

Security of oil supply is of the greatest importance in SE Europe due to the region high import dependency and the limited amount of domestic production. According to mid- term evaluation of Council Directive 2009/119 in 2017, while the transition to alternative sources of energy has started and is projected to accelerate in the future as a result of EU policies to decarbonise the economy and to implement the Paris Agreement on climate change, EU dependency on imports of crude oil and petroleum products remains today extremely high: the EU imports 89% of its oil demand. Given the important role of oil products in the current economy, holding emergency stocks that can be allocated quickly to where they are most needed in case of supply disruptions remains vital for the energy security of the Union [22].

Council Directive 2009/119 imposes an obligation on Member States to maintain minimum emergency stocks of crude oil and/or petroleum products. In accordance with Article 22 of Directive 2009/119/EC, the Commission in 2017 carried out, a review of its functioning and implementation ('mid-term evaluation'), which highlighted the need to introduce a number of technical changes to the Directive, in order to facilitate its implementation. Thus, the European Commission adopted an update to the Directive on minimum EU stocks of crude oil and/or petroleum products "Directive (EU) 2018/1581 of 19 October 2018 amending Council Directive 2009/119/EC as regards the methods for calculating stockholding obligations", to continue to guarantee the highest level of security of energy supply in Europe [23].

The oil dependency is aggravated by the lack of interconnections to facilitate oil flows and insufficient storage capacities. EU Balkan countries (Greece, Bulgaria, Romania, Croatia, Slovenia) as well as Energy Community Contracting Parties in SE Europe (Albania, North Macedonia, Kosovo, Montenegro, Serbia, B&H) made significant progress towards improving both domestic and regional oil supply security following the Decision of the Energy Community Ministerial Council which aims to adopt Directive 2009/119/ EC on "Imposing an Obligation to Maintain Minimum Stocks of Crude Oil and/or Petroleum Products" by 1 January 2023.

By this date, all countries of the region are required to hold oil stocks of 90 days of average net daily imports or 61 days of average daily inland consumption, whichever of the two quantities is greater, in order to be in a position to mitigate a supply crisis. They must ensure the appropriate procedures and structures enabling the authorities to release quickly, effectively and transparently emergency stocks in the event of a major supply disruption and impose restrictions on consumption. Toward this direction all the necessary steps must be taken to successfully establish a workable emergency stockholding system.

Albania

The oil industry is required by law to hold stocks equal to at least 90 days of average sales. The precise quantity of these stocks is determined based on the previous year's operations. Based on the Energy Community Implementation Report 2020, for the third year in a row, Albania failed to adopt the draft Law on the establishment, maintenance and management of security minimum stocks of crude oil and petroleum products. The draft Law continued to be discussed by stakeholders, but no progress was achieved. The current oil stockholding system is not compliant with Directive 2009/119/EC.

The main provisions of Directive 98/70/EC were transposed into Albanian legislation through the Government's Decision on the quality of fuel, petrol and diesel. However, the legislation should be amended to ensure that sulphur content in gas oil for nonroad mobile machinery (NRMM) is less than 10 mg/kg. Despite many efforts by the Government, some challenges are still to be tackled, including contamination that may occur during distribution, which is difficult to identify unless rigorous monitoring and analysis systems are in place [24].

Bosnia and Herzegovina

Bosnia and Herzegovina depends entirely on imports for its oil and hence it maintains a high degree of stocks of crude oil and petroleum products. Bosnia and Herzegovina has a total of approximately 800.000 m³ of storage space for crude oil and derivatives, of which about 533.000 m³ are located in the "Rafinerija nafte Brod" oil refinery and 82.000 m³ in the port of Ploče, operated by "Naftni terminali Federacije". As Energy Community reports states [24], the Ministry of Foreign Trade and Economic Relations continued to support a working group tasked to deliver concrete proposals or actions for the oil stocks model at the state level in compliance with the Oil Stocks Directive 2009/119/EC, but this did not result in any outcomes. Regarding monthly oil statistics, institutional cooperation was improved allowing the Ministry to access databases containing information on petroleum products on a monthly/daily basis. According to Energy Community' s Implementation Report 2020, the current legal framework is outdated and fails to meet the requirements of the Fuel Quality Directive. The Decision on Liquid Petroleum Fuels of 2002 was amended several times, with the latest amendment taking place in 2010 in order to allow the domestic Brod refinery to market liquid petroleum fuels below the standards set by the 2002 Law, which in turn are not compliant with the Directive. A new decision of the Council of Ministers should be adopted to incorporate the EU standards relating to fuel quality and environmental requirements. In particular, the maximum limit for the sulphur content in petrol, diesel and gas oil for non-road mobile machinery (NRMM) must be set at 10 mg/kg [24].

Bulgaria

The state-controlled State Reserve and War-Time Stocks Agency maintains, in compliance with the relevant EU Directive Obligation, oil stocks in Bulgaria equivalent to 90-days average local consumption.

Croatia

The Croatian Hydrocarbon Agency is responsible for maintaining the compulsory stocks of oil and petroleum products of the Republic of Croatia at the level corresponding to 90 days consumption by July 31st, 2012. Croatian Hydrocarbon Agency performs activities and carries out tasks within the scope of activities and competences prescribed by the Act, including all activities necessary for performing tasks stipulated by laws and other decisions, particularly the following:

- Collection of the fee for the compulsory stocks of crude oil and petroleum products.
- Purchase and sale of crude oil and petroleum

products for the purpose of forming and replenishing stocks.
- Organization, supervision and management of compulsory stocks of crude oil and petroleum products.
- Spending of funds for designated purposes in order to form and store compulsory stocks of crude oil and petroleum products.
- Determining the conditions for storing compulsory stocks of oil and petroleum products.

Cyprus

The Cyprus Organization for the Storage & Management of Oil Stocks (KODAP), which is the Central Stockholding Entity of Cyprus, established by "The Maintenance of Oil Stocks Law of 2003", (N.149(I)/2003), is responsible for maintaining and managing emergency stocks of crude oil and/or petroleum products as per the relevant obligation as applied to all EU Member States. It maintains, oil stocks in Cyprus and Greece, at a level equivalent to 90-days average local consumption.

These stocks have to be available at all times and only the Minister of Energy, Commerce, Industry and Tourism has the right to order the release of part or the whole of the oil stocks, in order to deal with shortages in energy supply.

Greece

Greece's combined storage capacity was around 10.2 mcm (equivalent to 64 million barrels) in 2018, and was used for industry operations and mandatory industry stocks. This shows that the country has sufficient storage capacity to meet the IEA 90-day obligation, which required Greece to have 3.5 mcm (22 million barrels) of oil storage capacity in 2018. Oil stocks are maintained by the country's two refinery groups (HELPE and Motor Oil), on behalf of the government.

Kosovo

According to Energy Community [24], the Oil Market Law of 2005 in Kosovo, as amended in 2009, fails to meet the requirements of the Oil Stocks Directive. Back in 2014, the Ministry of Trade and Industry finalized a compliant draft Law which was expected to be adopted in the fourth quarter of 2016 or first quarter of 2017. Despite the Secretariat's backing of the draft Law, the government has not approved it so far. Kosovo has transposed the main provisions of the Fuel Quality Directive. Certain diesel specifications (manganese maximum limit, cetane number, oxidation stability and distillation) should be improved by amending the 2017 Administrative Instruction. Sulphur content in gas oil for non-road mobile machinery (NMRR) should also be specified [24].

Montenegro

Montenegro depends entirely on imports of oil derivatives although there are good prospects for crude production from local oil fields and from the exploitation of the country's hydrocarbon resources. Since petroleum products are fully imported, they are a very important factor in terms of security of energy supply.

According to Energy Community, Montenegro did not make any progress during the reporting period in oil stockholding. No emergency oil stockholding policy is yet in place. The adoption of the draft Law on Security of Supply of Oil Products, which will regulate the manner of establishing and managing emergency oil stocks and the procedure in case of disruption of supply of petroleum products in line with the Oil Stocks Directive, is pending since 2016

The standards contained in the 2017 Regulation on limited values of contents of pollutant materials in liquid oil fuels fully comply with the specifications set out in the Fuel Quality Directive. Montenegro is planning amendments to the Law on Air Protection to introduce more precise provisions on fines [24].

North Macedonia

North Macedonia is obliged to maintain petroleum products reserves in the size that corresponds to no less than 90 days of average daily net imports, or 61 days of average daily consumption, whichever is greater. In 2018, the oil stock corresponded to 65 days, a 5 day decrease from 2017 reserves.

The government has transposed Directive 2009/119/EC on compulsory oil reserves in the national Law on Compulsory Oil Reserves and has prepared all requested secondary legislation. The Compulsory Oil Reserves Agency is responsible for the establishment, maintenance, storage and sale of compulsory oil and petroleum products reserves. However, the application of the new legislation has been postponed for 1 January 2021, while the compulsory oil reserve goals are to be met by 31 December 2022. According to the Action Plan [25], North Macedonia aims to hold 70% of required reserves in the country and 30% in EU countries. According to the Energy Community Implementation Report 2020 [24], the new Law on Compulsory Oil Reserves, adopted in October 2014, was supposed to be effective as of 1 January 2015 however, its application was postponed by Parliament several times. According to the latest amendment, the Law is envisaged to enter into force by 1 January 2021. There was slight progress in oil stockpiling during the reporting period but not on the approval of secondary legislation.The oil stocks corresponding to the average daily consumption increased by six days compared to the last reporting period.

North Macedonia's legal framework conforms to the Fuel Quality Directive to a large extent. In accordance with the current Law on Energy, the government of North Macedonia should adopt a new Rulebook on the Quality of Liquid Fuels within 18 months from the date of entry into force of the Energy Law, which was adopted in 2018. The Rulebook's adoption is pending [24].

Serbia

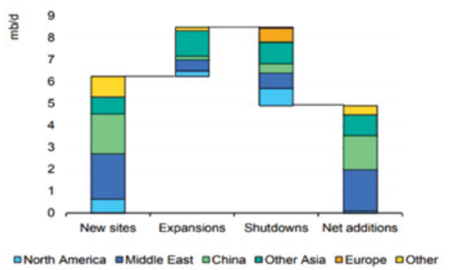
During the latest reporting period, activities on the formation of emergency oil stocks reserves continued. Two public procurements took place, one on the purchase of crude oil in the amount of 16 ktonnes and Euro Diesel in the amount of 6 ktonnes and one on the optional contract (ticket) for 50 ktonnes of petroleum product. The current estimated number of days of emergency reserves is 20 and calculated based on inland consumption. Since the entry into effect of the Rulebook on Technical and other Requirements for Liquid Fuels of Petroleum Origin in 2012, significant progress in conformity of the quality of fuels with European requirements has been achieved. Trade of leaded petrol on the market is forbidden and diesel quality is very good. However, gas oil used for non-road mobile machinery (NRMM) is permitted to contain sulphur of maximum 1000 mg/kg. This is far from meeting the current EU standards, which allow the sale of gas oil only if the sulphur content does not exceed 10 mg/kg [24].

9.1.7 Oil Refining

A third wave of refinery closures globally has been ushered in by the Covid–19 pandemic. Refining activity in 2020 fell almost 10% to 74.4 mb/d, a level last seen in 2010. Annual average refinery margins plunged to their lowest in at least two decades even as crude prices fell to 16–year lows. For the refining sector, the pandemic also offered a glimpse of the future, when clean energy transitions are expected to dramatically affect transport fuel demand, and petrochemicals become the only growing, or stable, oil demand segment. In 2020, as transport fuel demand fell by 13%, the petrochemical sector remained resilient [1].

The contraction in refinery activity is being driven by the downward shift in transport fuel consumption trends. A third of oil demand growth in 2019-2026 is now forecast to be met by products bypassing the refining sector, such as NGLs and biofuels. Refiners are increasingly looking at petrochemical integration to offset declines in transport fuels, and renewable diesel and electrolysis hydrogen production projects for refinery needs or for external users. Despite the dramatic slowdown in oil demand growth in 2020, refinery capacity additions continue unabated (Figure 9.38). Currently at some 102 mb/d, global crude distillation capacity is already 20 mb/d in excess of pre–pandemic refinery runs. Between 2020 and 2026, 8.5 mb/d of new refining capacity is expected to come online. With 3.6 mb/d of announced refinery closures, net additions will amount to 4.9 mb/d, similar to net capacity growth in the last seven years, but almost double the forecast growth in demand for refined products. This will result in a growing capacity overhang, which will require additional refinery shutdowns in the coming years [1].

Figure 9.38 **Refining capacity changes 2020-2026**

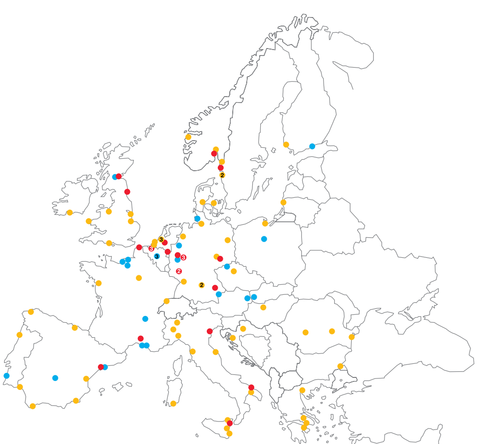


Source: IEA

Europe Overview

According to Fuels Europe, a large number of refineries are integrated with, or located very closely to steam crackers which produce the feedstock for the petrochemical industry. Such interconnections show how refining is an intrinsic part of the industrial value chain and provides the basis for advanced high value products (Map 9.11) [9].

Map 9.11 **Refinery/steam cracker sites in Europe**



Source:Fuels Europe

Fuels Europe indicated that in December 2019, there were 82 'mainstream' (capacity above 30 kbbdl/d or 1.5Mt/a) refineries in operation in the EU-28, Norway and Switzerland (Figure 9.39) [9].

Figure 9.39 **Refineries in Europe, Norway and Switzerland at the end of 2019**

COUNTRY	Number of refineries	COUNTRY	Number of refineries
Austria	1	Ireland	1
Belgium	3	Italy	10
Bulgaria	1	Lithuania	1
Croatia	2	Netherlands	6
Czechia	2	Poland	2
Denmark	2	Portugal	2
Finland	2	Romania	3
France	7	Slovakia	1
Germany	11	Spain	8
Greece	4	Sweden	3
Hungary	1	United Kingdom	6
EU TOTAL: Refineries = 79			
Norway	2		
Switzerland	1		
TOTAL NO + CH: Refineries = 3			
TOTAL: Refineries = 82			

EU NON EU

Source: Fuels Europe

The 82 mainstream refineries operating in 2019 in the EU-28, Norway and Switzerland had a primary refining capacity of 681 million tonnes. This represents a capacity decrease by some 75 million tonnes of primary refining capacity since 2010 [9].

Figure 9.40 **EU, Norway and Switzerland refineries capacity in 2019**

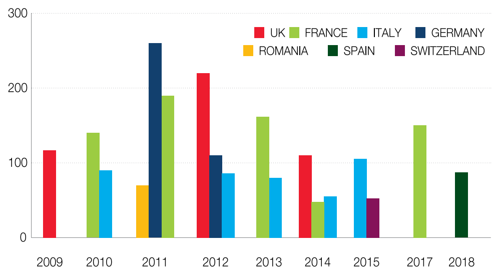
COUNTRY	*Refining capacity	COUNTRY	*Refining capacity
Austria	10	Ireland	3.6
Belgium	38.8	Italy	88.3
Bulgaria	9.8	Lithuania	9.5
Croatia	6.7	Netherlands	64.4
Czechia	8.8	Poland	25.2
Denmark	8.7	Portugal	15.2
Finland	13.0	Romania	10.8
France	63.5	Slovakia	5.8
Germany	97.0	Spain	68
Greece	21.2	Sweden	22
Hungary	8.1	United Kingdom	63.7
EU TOTAL: Refineries = 662.1 million tonnes per year			
Norway	16.0		
Switzerland	3.40		
TOTAL NO + CH: Refineries = 19.4 million tonnes per year			
TOTAL: Refineries = 681.5 million tonnes per year			

EU NON EU

Source: Fuels Europe

Since 2009, out of close to 100 refineries operating in Europe, 19 mainstream refineries were closed [9].

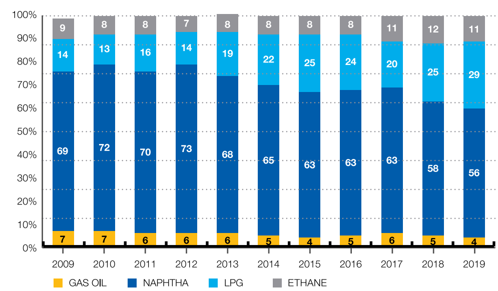
Figure 9.41 **Refinery closures in Europe**



Note: The threshold data used as basis for our report was lowered to 30 kbbdl/d or 1.5Mt/a, which added one refinery closure to the total (Dunkirk in 2014)Source: Fuels Europe

The EU refining sector is closely integrated with the petrochemical sector. A large part of the petrochemical feedstock relies on refined products, such as naphtha and petroleum gases [9].

Figure 9.42 **Chemical industry raw material use**



Source: Fuels Europe

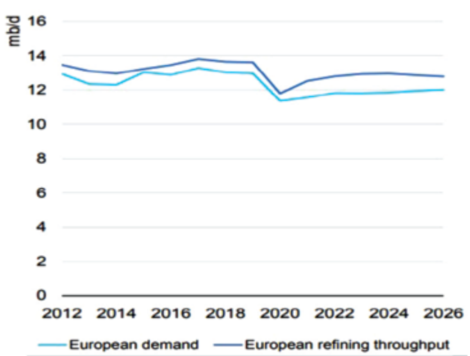
Prospects

According to IEA's "Oil analysis and forecast 2021" [1], Europe is often seen as the most vulnerable refining region due to its high dependence on feedstock imports, an unbalanced product demand barrel, which requires middle distillate imports and gasoline and other product exports, as well as the longer-term demand decline due to some of the world's most stringent decarbonisation policies. The latter also have an impact on refinery economics through carbon taxation and restrictions on operational emissions.

European refining has fallen from the peak rates seen in the early 2000s. Lower oil prices since 2014 helped stabilise activity levels. Growing demand over the same period did not result in higher refinery runs, increasing instead product imports. With new capacity coming online in the Atlantic Basin, notably in Mexico and Nigeria, European refiners will soon find themselves in an increasingly competitive market. Over the next six years, the downward demand trend is likely to return. IEA forecasts refinery runs falling 950 kb/d from the 2019 level, paralleling the decline in refined products demand. The change in product balances towards higher net imports mostly occurs through reduced exports of gasoline and fuel oil, as middle distillate imports decline, with higher yields and lower demand.

Some 2.6 mb/d of refining capacity was closed in Europe between 2007 and 2016. Since the start of the Covid-19 pandemic 640 kb/d has been slated for shutdown, with more rationalisation likely to follow in the coming years. Refineries located in industrial hubs with potential for integration with chemical and green hydrogen production will be more resilient than traditional fuel-oriented refiners located in areas that can easily be supplied from international product markets. While optimising and rationalising capacity, European refiners are leading in the field of green hydrogen, with several electrolysis projects at various stages of completion. They are also increasingly opting out of conventional upgrading unit investments and into renewable fuels production through co-processing and refinery conversions. Several circular economy projects, using mainly pyrolysis technology, are at planning or demonstration stages, aimed at converting municipal or plastics waste into fuels [1].

Figure 9.43 **Refining developments in Europe**



Source: IEA

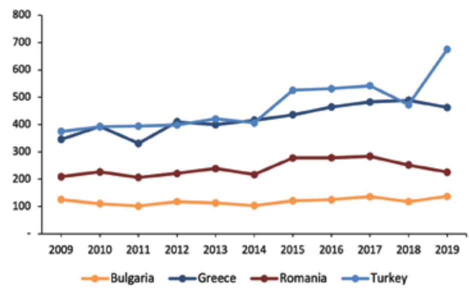
Refining in SE Europe

SEE countries have very limited oil supplies and are largely net importers of crude oil. Indeed, only 20 percent of the oil refined in SEE refineries originates from oilfields within the region. The demand for petroleum products outstrips domestic production, making the region, with the exception of Croatia and Macedonia, a net importer of petroleum products.

Yet the region's refineries are mostly underused. Increasing refinery throughput is difficult as only a small portion of the region's crude is directed to petroleum products. Most processed crude goes into gasoline and heating oil derivatives, with the market for these products limited in both size and margins [26]

The Statistical Review of World Energy, compiled by BP [27], indicates that in SE Europe Turkey leads the refineries capacity, among the selected countries, with 675,000 barrels/day, followed by Greece with 462,000 barrels daily (Figure 9.44).

Figure 9.44 **Refineries throughput (thousand barrels daily)**



Source: BP

Table 9.16 **Oil refineries in SE Europe**

Country	Refinery	Company	current CDU cap. (kbpd)	Date of Capacity change	
Albania	1	Ballsh Refinery	ARMO	20	
Albania	2	Fier Refinery	ARMO	10	
Bosnia & Herzegovina	1	Bosanski Brod	Zarubezhneft	80	
Bulgaria	1	Burgas	Lukoil	175	
Croatia	1	Rijeka	INA	90	
Croatia	2	Sisak	INA	85	
North Macedonia	1	OKTA Skopje*	Hellenic Petroleum	50	
Greece	1	Aspropyrgos	Hellenic Petroleum	148	
Greece	2	Elefsis	Hellenic Petroleum	106	
Greece	3	Thessaloniki	Hellenic Petroleum	90	
Greece	4	Corinth	Motor Oil Hellas	180	
Hungary	1	Százhalombatta	MOL Group	165	
Israel		Haifa Bay area	Bazan Group	197	
Israel		Ashdod	Paz Oil Company	91	
Romania	1	Ploiesti	Lukoil	50	
Romania	2	Petrobrazi Ploiesti	OMV Petrom	84	
Romania	3	Vega Ploiesti	Rompetrol	20	
Romania	4	Petrolsub Suplacu de Barcau	OMV Petrom	15	
Romania	5	Petromidia Constanţa / Midia	Rompetrol	100	
Serbia	1	Pancevo	NIS	103	
Serbia	2	Novisad	NIS	0 (-63)	Closure 1/3/2016
Turkey	1	Izmir	Tupras	221	
Turkey	2	Izmit	Tupras	221	
Turkey	3	Kirikkale	Tupras	100	
Turkey	4	Batman	Tupras	22	
Turkey	5	Star	Socar	214	Start up, May 2019

*not in operation Source: HELPE, IENE

Bulgaria

The main oil refinery in Bulgaria and one of the biggest in the Balkan peninsula is owned by Lukoil Neftochim Burgas AD and is located in Burgas. It has a primary processing capacity of 9.8 Mt of crude oil per year and supplies liquid fuels, petrochemicals and polymers, being among the leading suppliers of petroleum products in the Balkan region and also distributes motor fuels to the rest of Europe & USA. There are three other manufacturers of petroleum products - "Bulgarian Oil Refinery" EOOD, "INSA Oil" Ltd. and "Polisan" AD.

Table 9.17 **Evolution of refineries in Bulgaria**

	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Refineries	1	1	1	1	1	1	1	1	1	1	1	1
Primary capacity (kbbl/cd)	195.0	195.0	195.0	195.0	195.0	115.2	115.2	115.2	115.2	115.2	95.0	95.0
Primary capacity (Mt/a)	9.8	9.8	9.8	9.8	9.8	5.8	5.8	5.8	5.8	5.8	4.8	4.8
Percentage of EU Total	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.1%	1.0%	1.0%	0.9%	0.9%	0.9%

Source: Concawe [28]

Croatia

Table 9.18 presents the refineries status in Croatia since 2009.

Table 9.18 **Evolution of refineries in Croatia**

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Refineries	2	2	2	2	2	2	2	2	2	2	2
Primary capacity (kbbl/cd)	134.1	134.1	134.1	170.0	170.0	170.0	170.0	170.0	170.0	115.2	115.1
Primary capacity (Mt/a)	6.7	6.7	6.7	8.5	8.5	8.5	8.5	8.5	8.5	5.8	5.8
Percentage of EU Total	2.1%	2.1%	2.1%	2.2%	2.2%	2.1%	2.0%	2.0%	1.9%	1.8%	1.8%

Source: Concawe

INA-Industrija nafte, d.d. (INA, d.d.) - INA Group has a leading role in Croatian oil business and enjoys a strong position in the region in oil and gas exploration and production, oil processing, and oil products distribution activities. The Group owns and operates two oil refineries: Oil Refinery Rijeka (Urinj) and Oil Refinery Sisak and a lubricant plant: Lube Refinery Zagreb Ltd.

Rijeka oil refinery (Urinj) is located in the northern part of the Adriatic Sea. It is the shortest and most convenient connection to central Europe and with the Mediterranean. In Rijeka INA has a built road, railway, marine and pipeline infrastructure for the supply and shipment of products, crude oil and petroleum derivates. Rijeka oil refinery is connected through a 7.2 Km underwater pipeline with the port and petroleum terminal in Omišalj, on the island of Krk (owned by JANAF).

The capacity of the oil refinery at Rijeka is 4.4 million tons/annum. In 2011, INA carried out a comprehensive modernization and upgrading plan of the refinery. Apart from the modernisation of existing units, a new port with a closed coke storage facility and greater overall complexity has been added.

The Sisak oil refinery is an inland refinery located some 50 kilometres to the south of Zagreb. The capacity of the Sisak Oil Refinery is 2.2 million tons/annum. The refinery development program foresees the concentration of crude oil processing activities in the Republic of Croatia at the Rijeka Oil Refinery and, as part of this, the conversion of the Sisak Oil Refinery into an industrial centre is foreseen. As part of the renovation work attention was given to the development of bio-component processing projects. These operate profitably and contribute to the positive development of the regulatory environment in the EU and the Republic of Croatia. As part of INA's renovation project a modern logistics centre has been included together with bitumen production, lubricant production and other sustainable and economically viable activities.

Greece

As Table 9.19 indicates [28], in Greece operate four refineries which represent 4.5% of total EU capacity for 2020.

Table 9.19 **Evolution of refineries in Greece**

	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Refineries	4	4	4	4	4	4	4	4	4	4	4	4
Primary capacity (kbbl/cd)	423.0	423.0	423.0	423.0	465.5	465.5	465.5	465.5	465.5	474.5	456.0	399.0
Primary capacity (Mt/a)	21.1	21.1	21.1	21.1	23.4	23.4	23.4	23.4	23.4	23.7	22.9	20.0
Percentage of EU Total	4.5%	4.3%	4.3%	4.3%	4.3%	4.3%	4.2%	4.0%	3.9%	3.7%	3.6%	3.6%

Source: Concawe

The production of Hellenic Petroleum Group's refining sector recorded a slight drop and amounted to 14.2 million tons in 2019. The group's sales were impacted commensurately and amounted to 15.2 million tons; exports stood at 7.9 million tons or 52% of total sales, and sales of aviation and shipping fuel were up 5% at 2.8 million tons.

The production of the Motor Oil refinery also recorded a slight decline in 2019 compared to 2018 and amounted to 12.1 million tons, while sales stood at 14.4 million tons at approx. the same levels as in 2018. It is worth noting that Motor Oil's lower production and quantity of crude oil and raw materials processed in 2019 compared to 2018 was due to the scheduled periodic maintenance of the refinery's units. The Motor Oil refinery has also acquired the flexibility to process a broad range of crude oil types; thus, contributing to import diversification. Furthermore, the refinery can now easily switch between diesel and gasoline production and adapt to seasonal changes in Greece's demand. The upgrade and modernisation works, which took place back in 2010-2012, have placed the refineries among the most profitable in Europe, with modern and environmental – friendly specifications.

Table 9.20 **Oil refineries in Greece**

	Hellenic Petroleum (HELPE) S.A.			MOTOR OIL
Ownership	Paneuropean Oil and Industrial Holdings S.A. (47%) Institutional (8.7%) and Private (8.8%) investors Hellenic Republic Asset Development Fund: 35.5%			Petroventure Holdings Limited: 40,0%; Doson Investments Company: 8,1%; Free float: 51,9%
Location	Aspropyrgos	Thessaloniki	Elefsina (Corinth)	Agioi Theodoroi
Type of Refining	Highly complex: fluid catalytic and thermal cracking; vacuum distillation, naphtha & diesel hydrotreating; isomerisation; reforming; mild hydrocracking; bio-ethers (ETBE/TAEE) & propylene production	Hydroskimming: vacuum distillation, naphtha & diesel hydrotreating; isomerisation; reforming	Highly complex: high pressure hydrocracking and thermal cracking; vacuum distillation; diesel hydrotreating; steam reformer;	Complex: catalytic and thermal cracking; isomerisation; MTBE production; vacuum distillation; mild hydrocracking; hydrotreating; reforming; lube production; alkylation; dimerisation
Nelson Complexity Index	9.7	5.8	12	11.54
Capacity (Mt/year)	7.5	4.5	5.3	10
Capacity (kb/d)	148	90	106	185
Year established	1958	1966	1972	1972

Source: HELPE, MOTOR OIL (https://www.helpe.gr/en/investor-relations/key-data/short-description/)

Other characteristics of the aforementioned refineries are presented below.

Aspropyrgos refinery [29]

- It has undergone several upgrades, the most important being:
  - Residue conversion project and installation of FCC, mild hydrocracker, visbreaker and CCR units (1986).
  - Refining capacity increase to 148,000 bbl/d (1999).
  - Revamp and extensive upgrade of the conversion units (2004).
- It has a significant number of main distillation units and subsequent conversion units.
- It is very flexible concerning production, storage and distribution of products: gasoline or diesel production may be increased based on market trends.
- The refinery owns a large private port, an extensive crude oil distribution pipeline network from and to the cruse oil unloading and storage installation in Pachi, Megara, and a distribution pipeline for finished and semi-finished products for and to the Elefsina refinery. It also has the main responsibility for fuel supply through pipeline to the Eleftherios Venizelos Athens International Airport.
- The refinery is connected to the gas network with significant energy and environmental benefits.
- From November 2019, the refinery began implementing the new IMO/MARPOL Directive, so it further diversified its crude slate through processing very low sulfur crude oils, with the objective of producing 0,5% sulfur fuel oil and marine gasoil.
- In December 2019, following the completion of the conversion of the gasoline blending components MTBE and TAME production units into ETBE and TAEE production units respectively, the Aspropyrgos refinery began producing bio-ethers. The modifications were put in place so that Hellenic Petroleum can meet the obligation to supply E5 gasoline in the domestic market, without any bioethanol addition, so as to improve the quality of the final product and substitute imports.

For 2020, measures to improve the environmental footprint in context to compliance with the new emission levels linked to Best Available Techniques (BAT) were incorporated into the new environmental permits approving the operating conditions of the Aspropyrgos refinery.

In addition, as part of the planned turnaround at Aspropyrgos refinery, environmental upgrade projects were also successfully completed, including the preparation for the installation and operation (in 2021) of a new electrostatic particulate filter (ESP), which is expected to lead to a 50% reduction in the refinery's total particulate emissions (PMs).

Elefsina Refinery [29]

- An upgrade took place, which was completed in 2012, and worth €1.5 billion making it one of the most modern and complex refinery in the Mediterranean region. The upgrade included the installation of three main units: a high pressure hydrocracking unit with a capacity of 39,000 bbl/d; a thermal cracking unit with a capacity of 20,000 bbl/d and a vacuum distillation unit.
- The upgrade boosted HELPE' s competitiveness at it increased the yield of middle distillate replacing high sulfur fuel oil and maximizing diesel production by consuming high sulfur crude oil. The investment reduced emissions, specifically, sulfur dioxide emissions decreased by 70.2%, nitrogen oxide emissions by 11.6% and particulate matter emissions by 84.2%.
- It is a strategically important refinery for HELPE, due to its high storage capacity (3,3 million m^3 of crude oil and petroleum products) and the logistics infrastructure for imports and exports management, including a large private port and a tank truck loading station.

For 2020, measures to improve the environmental footprint in context to compliance with the new emission levels linked to Best Available Techniques (BAT) were incorporated into the new environmental permits approving the operating conditions of the Elefsina refinery. Note that in 2020, the environmental permit for the Elefsina refinery was issued in accordance with Best Available Techniques (BAT).

Thessaloniki refinery [29]

- It is of a hydroskimming type and has a 1.4 million m3 storage capacity.
- The refinery's upgrade was completed in 2011 and can be divided into three main projects: a. distillation units renovation, b. storage capacity increase c. new Continuous Catalytic Regeneration Reformer as well as a desurlurization unit for miximizing gasoline and diesel production.
- The upgraded Thessaloniki refinery, continued the refinging of high margin crudes, minimizing the additive in gasoline production and the consumption of natural gas. The new Continuous Catalytic Reformer Unit has enabled the refinery to process additional naphtha for the Elefsina refinery, on top of own naphtha production, maximizing the system refining margins.
- Its energy efficiency levels were improved following the preventive maintenance works on piping and steam traps.

For 2020, measures to improve the environmental footprint in context to compliance with the new emission levels linked to Best Available Techniques (BAT) were incorporated into the new environmental permits approving the operating conditions the Thessaloniki refinery (expected to be issued in 2021).

Motor oil refinery [30]

- The refinery produces all types of fuel and is one of the most advanced and complex in Europe, with Hydrocracker and Catalytic Cracking units
- It produces refined fuels (gasoline and automotive diesel) in accordance with the EU specifications.
- It is the only refinery in Greece with a unit producing base oils and finished lubricants, approved by such international agencies as the American Petroleum Institute (API), the European Automobile Manufacturers Association (ACEA) and the United States Army and Navy.

- It possesses a power and steam cogeneration unit, which now has a capacity of 85 MW following the recent addition of a fifth gas turbine.
- It uses natural gas as a fuel and as a raw material for the production of hydrogen.
- It has a storage capacity of 2,600,000 m^3 (Crude Oil: 1,000,000 m^3, Intermediate & Finished Products: 1,600,000 m^3).
- It has modern port facilities for tanker docking, suitable for tankers of up to 450,000 tons DWT, which can serve more than 3,000 vessels annually.
- It has a modern truck loading terminal, which can serve 220 tanker trucks per day and significantly strengthens the competitive position of Motor Oil in the southern Greek market.

Romania

Romania has a long tradition as the oldest crude oil producer and refineries in Europe being a pioneer in hydrocarbon development since the end of 19th century. Before the Second World War, Romania used its onshore reserves to become Europe's largest oil producer. The country still holds a proud place among Eastern European nations, but in recent years its offshore industry has remained mostly idle.

The main players in the downstream sector are OMV Petrom (the main player on the Romanian fuels market with a 32% market share also in the region), Rompetrol (8% market share in Romania) and Lukoil. OMV Petrom operates one refinery in Romania - Petrobrazi. Petrobrazi refinery has a capacity of 4.5 million tons per year and a utilization rate of 97% in 2019 (up from 85% in 2018). Petrobrazi can process OMV Petrom's entire Romanian equity crude oil. The refinery also has a hydrogen plant on its premises. Its latest upgrade was the Polyfuel plant, an investment worth 65 million EUR.

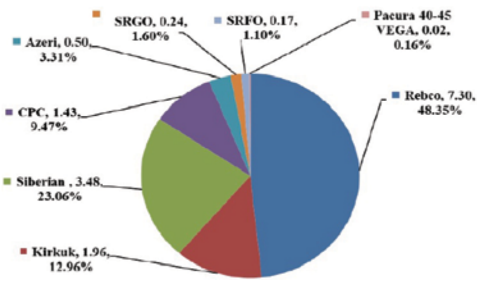
The plant allows 90,000 tons of high octane gasoline and diesel to be obtained through reconversion of LPG and low-grade light gasoline.

The unit is "the third of its kind worldwide and the first to convert low-grade light gasoline as well, not just LPG" according to the company annual report for 2019. OMV Petrom has a network of 793 filling stations in the Black Sea region, most of which (556 stations) are located in Romania. It has 94 filling stations in Bulgaria and 81 in Moldova. Rompetrol operates 2 refineries in Romania: the Petromidia Refinery (in Constanta) and the Vega refinery (in Ploiesti) and a petrochemical plant (in Navodari, Constanta). Petromidia refinery is the largest in Romania and one of the most modern in the Black Sea region with a Nelson complexity index of 11.4.

Ranked 9th among 250 refineries in Europe and Africa by Wood MacKenzie in 2018. The refinery has the highest white product output in the region (86.2%) and a utilization rate of 90% (higher than the average European utilization rate of 83%). In addition, it has the highest capability in the region to extract sulphur from oil, obtaining exclusively Euro 5 fuels. Kazakstan's stock oil company -KazMunayGaz (KMG)- has invested 1.6 billion USD since it took over the company in 2000, of which 1 billion USD was invested in Petromidia from 2007 to 2012.

The largest project was the upgrade and increase of its capacity from 3.5 Mt/year to 5 Mt/year, a project worth 450 million USD. The total feedstock processed by Petromidia in 2019 was 6.33 million tons while gasoline production was 1.37 million tons, jet group production was 406 ktons, diesel production 2.93 million tons (highest ever).

Figure 9.45 **Petromidia refinery: feedstock structure in 2019 (in 000 tons/day, and % it represents)**



The yield for diesel was 48.5% and for fuels (gas, diesel, Jet, automotive LPG fuel) is 75.4%. The finished products are sold on the domestic market as well as on the international market.

The main export markets, by petroleum product, are:

- gasoline: Greece, Georgia, Lebanon, Bulgaria, Moldova, Turkey;
- diesel: Greece, Bulgaria, Moldova, Turkey, Georgia;
- jet fuel: Moldova, Georgia, Bulgaria, Albania;
- petcoke: Turkey, Moldova, Ukraine, Serbia, Hungary;
- sulphur: Egypt, Ukraine.

Table 9.21 **Petromidia refinery: structure of deliveries in 2019**

	DELIVERIES						
OIL PRODUCTS	TOTAL DELIVERIES	DOMESTIC *		EXPORT		TRANSFER	
	[tons]	[tons]	[%]	[tons]	[%]	[tons]	[%]
Gasoline	1,376,024	357,266	25.96	1,018,758	74.04		
Gasoline for chemical use	232,965	0	0.00	27,779	11.92	205,186	88.08
Petroleum	406,180	316,369	77.89	78,826	19.41	10,986	2.70
Auto diesel fuel	2,927,053	1,890,099	64.57	1,036,954	35.43	0	0.00
Fuel oil	182,204	6,604	3.62	29,256	16.06	146,343	80.32
Vacuum distillation	152,561	0	0.00	0	0.00	152,561	100.0
Propylene	284,304	284.304	100.0	0	0.00	0	
Liquefied Petroleum Gas LPG	264,804	178,678	67.47	86,131	32.53	0	
Petroleum Coke	54,147	78	0.14	57,069	99.86	0	
Petroleum Sulphur	72,682	39,396	54.20	0	0.00	33,286	45.80
Other Products	1,376,024	357,266	25.96	1,018,758	74.04	0	
TOTAL	**5,955,930**	**3,072,857**	**51.59**	**2,334,773**	**39.20**	**548,362**	**9.21**

** The quantities delivered for domestic consumption include the petroleum products marketed on the domestic market. The deliveries to Vega and Petrochemical are included under the heading "transfer"*

Most of the gasoline produced at Petromidia is exported (1 million tons or 74%) and only 357,000 tons (26%) is supplied to the domestic market. In contrast, most of the diesel fuel (1.9 million tons, or 65%) and most of the LPG (178, 678 tons or 68%) is sold in the domestic market. Overall, 52% of the finished products are absorbed by the domestic market, and 40% are exported.

Motor fuels (gasoline, diesel, LPG) account for 80% of total finished products sales. Vega refinery is the oldest processing unit in Romania (115 years). It is the only domestic producer of bitumen and hexane. Its total feedstock in 2019 was 436 kt while hexane production was 92 kt and bitumen production was 120 kt. Vega works in perfect synergy with Petromidia refinery.

Table 9.22 **Vega refinery: structure of petroleum products deliveries in 2019**

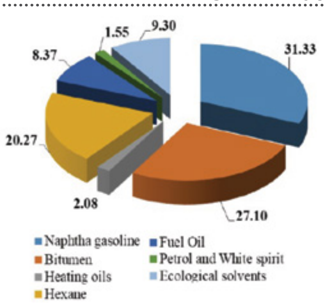
Group of products	TOTAL DELIVERIES 2019		DOMESTIC		EXPORT	
	[tons]	% of total sales	[tons]	%	[tons]	%
Naphtha gasoline	138,953	31.33	48,823	35.14	90,130	64.86
Bitumen	120,199	27.10	119,219	99.18	980	0.82
Heating fuels	9,247	2.08	9,247	100.00	-	-
Hexane	89,889	20.27	3,110	3.46	86,779	96.54
Heavy fuel oil	37,120	8.37	36,833	99.23	287	0.77
Petroleum and White spirit	6,890	1.55	4,926	71.50	1,964	28.50
Ecologic solvents	41,228	9.30	679	1.65	40,549	98.35
Total	**443,526**	**100.00**	**222,837**	**50.24**	**220,689**	**49.76**

Vega focuses on the production of solvents (SE 30/60, n-Hexane, white spirit)), naphta, heating fuels, normal road bitumen and modified bitumen. Two thirds of the naphta gasoline produced at Vega is exported. The entire bitumen production (119,219 tons or 99%) and 100% of the heating fuels (9,247 tons) is used in the domestic market, as is 99% of the heavy fuel oil produced. On the other hand, ecological solvents go mainly to export (98%).

The main export markets for petroleum products produced at Vega are:

- naphta: Hungary, Slovakia, Czech Republic, Poland, Spain;
- hexane: India, Turkey, Ukraine, Bulgaria, Russia;
- ecological solvents: Germany, Cyprus, Spain, Ukraine, Hungary, Moldova;
- white spirit: Bulgaria, Moldova;
- fuel oil: Bulgaria;
- bitumen: Bulgaria.

Figure 9.46 **Structure of Vega sales, by product (in %)**



Navodari petrochemical plant is the only producer of polypropylene (PP) and polyethylene (LDPE, HDPE) in Romania (Table 9.23).

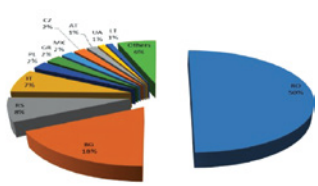
Table 9.23 **Navodari petrochemical plant: structure of polymers deliveries in 2019**

Products	Deliveries				
	Total Deliveries	Domestic		Export	
	(tons)	(tons)	(%)	(tones)	(%)
PP	91,771	40,112	44%	51,659	56%
LDPE	38,121	25,053	66%	13,069	34%
HDPE	3,316	1,101	33%	2,215	67%

Note: PP = polypropylene; LDPE = low density polyethylene; HDPE = high desnity polyethylene.

In addition to its own products, the petrochemical plant also sells products in high demand on the domestic market, such as HDPE variants, LLDPE, PVC, or PET. The main markets for polymers (PP, LDPE, HDPE, PET, PVC) are Romania (50%), Bulgaria (18%, Serbia (8%) and Italy (7%).

Figure 9.47 **Polymer sales by destination 2019**



Petrotel-Lukoil was built in 1904, which is why it was also the first to be modernized. Until 2013-2014, Lukoil's Romanian refinery was the most advanced one in its portfolio of refineries outside Russia (and the only one with a Nelson index of 10 at the time). Following subsequent upgrade and modernization programs in other refineries, this is no longer the case, as the Greek refineries (Elefsina and Corinth), Burgas refinery (Bulgaria) and Isab refinery (Italy) now have a higher Nelson index than Petrotel (in Romania). In terms of refining capacity, Petrotel-Lukoil has the lowest refining capacity (only 2.7 million tons) compared to Burgas (7 million tons) or Isab (14 million tons). Petrotel processes Urals oil and oil produced at Romanian fields. Its refining throughput was 2.485 million tons in 2019.

Table 9.24 **Key figures for Petrotel Lukoil refinery in Romania**

	2015	2016	2017	2018	2019
Refining capacity, mln t/year	2.7	2.7	2.7	2.7	2.7
Nelson index	10	10	10	10	10
Refinery throughput mln t	2.237	2.771	2.368	2.723	2.485
Petroleum products output, mln t	2.173	2.709	2.320	2.659	2.368

The refinery is located in Ploiesti, 55 km away from Bucharest. Crude is delivered to the refinery by railway and via a pipeline from Constanta. Finished products are shipped by railroad and motor trucks.

Serbia

Crude oil refining in the Republic of Serbia is carried out in Pančevo Oil Refinery, which belongs to NIS JSC. The Pančevo Oil Refinery has been in operation since 1968 when it started with the first complex plants with primary processing capacity of 1.32 MTA and with the subsequent opening of other secondary plants in 1969. The refinery then reached the design capacity of 4.8 MTA [6].

The crude oil is transported to the oil refinery by pipeline, waterways, rail tankers and road tankers. Thanks to its refining capabilities, Pančevo Oil Refinery can practically process all types of crude oil and produce fuels - liqufied petrol gas, petrol, diesel fuel, jet fuel, heating oil and bitumen and petrochemical products. The capacity utilization is over 60% and storage facilities have a capacity of 700,000 m3. Since 2014, the domestic and imported crude oil which is processed averages 3 MTA.

Adjacent to the Pančevo Oil Refinery is "HIP-Petrohemija a.d. Pančevo" (Petrohemija JSC), which consists of a pyrolysis plant for ethylene production under the trade name "Etilen". The refinery provides most of the raw material for this plant, so the pyrolysis petrol which returns to the refinery is very rich in aromatic hydrocarbons, especially in benzene. The crude petrol from the refinery to Petrohemija JSC and the pyrolysis petrol from Petrohemija JSC to the refinery are transported through petroleum products pipelines. In recent years, following modernization of the refinery has expanded its primary and secondary capacities. Serbia's other major refinery is located at Novi Sad. The Novi Sad Oil Refinery presents a complex of refining and auxiliary factory plants for refining of oil and petroleum products, tank, transport - manipulative, research and laboratory facility and other accompanying facilities. It is located in the industrial zone of Novi Sad, located directly on the Danube and the navigable DTD channel. The refinery commenced operation in 1968, with designed capacity of refining 3 MTA. In recent years, the refinery mostly processed the domestic oil of Velebit type using a production capacity of only 0.5 MTA.

The modernization program of Pančevo Oil Refinery envisaged a total budget of 547 million euros, of which 396 million corresponds to construction of a hydrocracking complex, the rest 151 million euros is foreseen for the projects of ecological significance - the construction of plants for the production of hydrogen in Pančevo Oil Refinery, as well as the modernization and construction of relevant industrial infrastructure.

The investment program, which included the modernization of production capacities and technological reconstruction of the processing complex, in order to increase product quality up to the standard Euro - 5 as well as the environmental protection was implemented to the fullest extent. Until now, over 60 millions € have been invested in environmental projects, in parallel with the modernization of production. Thanks to the modernization programme, NIS JSC now fully satisfies the needs of the domestic market for fuels with 10 ppm S and unleaded petrol. The realization of the complex for mild hydrocracking and hydro (complex MHC/DHT) in Pančevo refinery, enabled the NIS JSC to completely switch to the production of ecologically clean fuel - unleaded petrol and euro diesel with a sulfur content not exceeding 10 ppm. In 2016, the realization of Deep Processing project ("Coking") continued which is the second phase of modernization of the refining complex, with the aim of completing the desulphurisation process in refinery capacities [6].

Turkey

Turkey has five refineries (Table 9.25) in operation with a total capacity of 860,000 b/d in 2019 and an average capacity utilisation rate of 90%. Total refinery production increased in 2019 by 31% to 774.1 kb/d, with increases in all refined products: diesel production rose by 54.3% (to 272.9 kb/d), aviation kerosene by 24.6% (to 128.8 kb/d), gasoline production by 12.9% (to 122.7 kb/d), LPG by 18.6% (to 34.4 kb/d) and naphtha production more than tripled to 27.7 kb/d in 2019. Domestic diesel production from all refineries in 2019 stood at 272.9 kb/d, covering 59% of the country's demand of 470.8 kb/d (up from 40% coverage in 2018). Meanwhile, domestic gasoline production is twice the level of consumption. As such, domestic gasoline refiners were focused on exports; most Turkish gasoline exports were directed to Egypt, Spain, the United States and Gibraltar. There were no imports of gasoline in 2019 [20].

The Izmit refinery began production in 1961 with capacity to process 1 million tons/year crude oil. As a result of significant capacity increases and the conversion unit investments over the years, the refinery's design capacity reached 11.3 million tons/year. Producing to Euro V standards, İzmit Refinery located in a consumption center, accounting for 33% of Turkey's consumption of petroleum products. A total of 12.2 million tons of material, including 10.5 million tons of crude oil and 1.7 million tons of semi-finished products, were processed at the İzmit Refinery in 2020. As of the end of 2020, the refinery's total product sales amounted to 13.4 million tons, of which 10.7 million tons were domestic sales. After the Fuel Oil Conversion Facility was commissioned, the Izmit refinery reached one of the highest conversion rates in the world, with a Nelson Complexity value of 14.5 [31].

With the aim of meeting Turkey's growing requirement for petroleum product, the Izmir refinery was brought into operation in 1972. The refinery, which started production with an annual crude oil processing capacity of 3 million tons, was registered as having in 2020 an annual refining capacity of 11.9 million tons, following significant capacity increases and unit modernizations carried out over the years. A total of 6.0 million tons of products were sold from the Izmir refinery in 2020, with 4.4 million tons of this amount sold domestically. The Izmir refinery, which has a Nelson Complexity Index of 7.66, is the only refinery in Turkey to have a machine oil production complex, with a 400,000 tons/year capacity [31].

The Kırıkkale refinery was established in 1986, to meet the petroleum demands of the Ankara, Central Anatolia, Eastern Mediterranean and Eastern Black Sea regions. The Kırıkkale refinery has an annual 5.4 million ton crude oil processing capacity; its crude oil supply is realized via BOTAŞ's Ceyhan Terminal and the Ceyhan-Kırıkkale pipeline. In 2020, the refinery processed a total of 4.6 million tons, including semi-finished products, and 85% capacity utilization was achieved.

It has become a facility with mid level complexity with the addition of hydrocracker, isomerization, diesel desulphurization and CCR reformer units. With a Nelson complexity of 6.32, the Kırıkkale refinery has Turkey's largest road tanker filling capacity. [31].

The Batman refinery was the first refinery to be founded in Turkey in 1955, with a crude oil processing capacity of 330 thousand tons. Following the commissioning of a new crude oil processing unit in 1972, the Batman refinery's annual crude oil processing capacity in 2020, was 1.4 million tons. In 2020, the Batman refinery processed 942 thousand tons of crude oil in the bitumen mode and sold 746 thousand tons product. The refinery has the advantage of being located near domestic sources of crude oil; however, since it does not have upgrading units, its configuration is simple and its Nelson complexity index is 1.83 [31].

The fifth and newest refinery in Turkey is the STAR refinery, was commissioned on October 19, 2018. With an additional storage investment, the project reached in total an investment amount of 7 billion US dollars [32]. The STAR refinery is located just 4 km south of the Izmir refinery of TÜPRAŞ and belongs to SOCAR from Azerbaijan. In August 2019 the STAR refinery reached its planned capacity of 10 mill t/year. The STAR refinery produces 4.8 mill t/year diesel, 1.6 mill t/year aviation fuel, 0.7 mill t/year Petroleum coke and 0.3 mill t/year LPG mainly destined for the domestic fuel market. It also supplies the PETKIM petrochemical complex of SOCAR, on the same site, with 1.6 mill t/year naphtha, 0.4 mill t/year xylene and 0.5 mill t/year reformat.

Table 9.25 **Refineries operating in Turkey in 2019**

	Capacity (b/d)	Location	Company	Nelson complexity	Year of construction
İzmir refinery	257 000	Izmir	Tüpraş	7.7	1972
İzmit refinery	244 000	Körfez/Kocaeli	Tüpraş	14.5	1961
STAR refinery	214 000	Aliağa/İzmir	SOCAR	7.4	2018
Kırıkkale refinery	115 000	Kirkkale	Tüpraş	6.3	1986
Batman refinery	30 000	Batman	Tüpraş	1.8	1955

Note: The Nelson Complexity Index is a measure of refinery complexity.
The index measures the complexity and cost of each major type of refinery equipment.
The larger the Nelson Index of a refinery, the more complex it is.

Source: IEA

Table 9.26 **Production Amounts by Product Type and Refinery in 2019 (tonnes)**

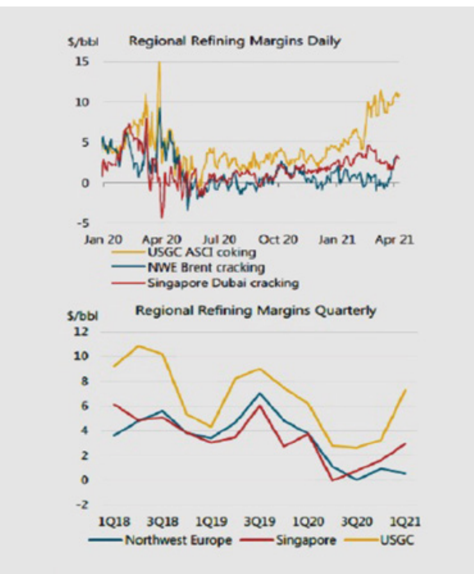
Product Name	TÜPRAŞ İzmit Refinery	TÜPRAŞ İzmir Refinery	TÜPRAŞ Kırıkkale Refinery	TÜPRAŞ Batman Refinery	Star Refinery	Total
Unleaded Gasoline 95 Octane	2.789.149,280	1.775.938,033	719.779,892	-43,387		5.284.823,818
Unleaded Gasoline 98 Octane		3.044,115				3.044,115
Diesel	5.357.302,014	3.103.505,193	1.793.557,821	-98,059	3.387.846,702	13.642.113,671
Fuel Oil (Sulphur content between %0,1 and %1)	-213.906,301	-173.828,076	-5.096,861			-392.831,238
Heating Oil (Sulphur content between %0,1 and %1)	128.863,659	47.835,776				176.699,435
High Sulphur Fuel Oil (Sulphur content exceeding %0,1)	-155.427,152	303.556,060	13.471,787		410.677,448	572.278,143
Jet Fuel (Kerosen)	2.776.570,163	1.519.765,779	522.716,667		1.145.785,240	5.964.837,849
Marine Fuel (Residual)	931.261,874	1.307.137,764				2.238.399,638
Marine Fuel (Distelled)	57.651,468	49.408,451				107.059,919
Gas Oil			-1.242,030			-1.242,030
Total	11.671.465,005	7.936.363,095	3.043.187,276	-141,446	4.944.309,390	27.595.183,320

Source: Republic of Turkey – Energy Market Regulatory Authority [7]

Refining Margins

Gasoline was the single bright spot in global product markets in the 1H 2021, according to the IEA, with crack spreads in all major refining centres continuing their upward trend since the start of the year. US margins posted the sharpest month-on-month increases, partly demand-fuelled, and partly due to lingering supply outages from February winter storms. US Gulf coast gasoline cracks surged by almost $8/bbl to $22.83/bbl on a monthly average basis, the highest since July 2019. By mid-March, US gasoline stocks dropped to seven-year seasonal lows [14]. At the same time, the increase in gasoline cracks in Europe was likely due to the combination of US factors and the seasonal specification change to summer gasoline, which is more expensive to blend. Renewed lockdowns in several countries on the continent did not leave room for a regional gasoline demand uptick [14].

Figure 9. 48 **Regional Refining Margins Daily (Up) and Regional Refining Margins Quarterly (Down)**



Source: IEA

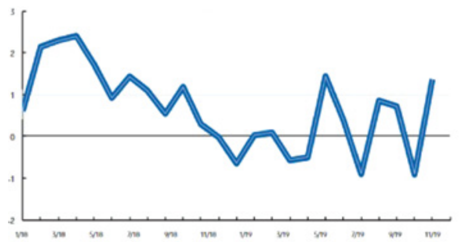
Naphtha cracks continued retreating in Europe and in Singapore. The one-week blockage of the Suez Canal (March 2021), did not provide a lot of support to Singapore cracks. Nor did it have a visible impact on North West Europe cracks. The canal is a major transit route for European naphtha and fuel oil flows to Asia.
Diesel cracks were stronger in the US Gulf Coast on weather-related supply issues, but they were weaker in Europe and Singapore, as higher crude prices eclipsed product increases, with demand likely remaining flat at best m-o-m. Jet kerosene cracks also deteriorated, with new travel restrictions and the end of winter heating demand season. On a monthly average basis, European and Singapore jet cracks fell to levels last seen before the heating demand spike at the beginning of winter.

Fuel oil cracks declined slightly on a monthly average basis. The Suez Canal closure provided only a marginal boost to cracks, predominantly for bunker fuels, as the bypass of the canal requires 10-14 additional days at sea. The 0.5% fuel oil cracks in Singapore nevertheless fell $2.70/bbl. With gasoline cracks providing the only positive support to refiners, the upward trend in margins was limited to US regional benchmarks. In North West Europe, sour margins were supported by weaker Urals differentials, while sweet margins fell on a monthly average basis. Brent complex margins were negative for most of March but spiked at the end of the month with lower crude and higher gasoline prices. Singapore margins saw more substantial falls and sharply lower 0.5% fuel oil cracks [14].

Benchmark margins for Mediterranean refineries were significantly weaker in 2019, at the lowest levels in the last 5 years. Key drivers were supply/demand balances of products and Urals crude pricing.

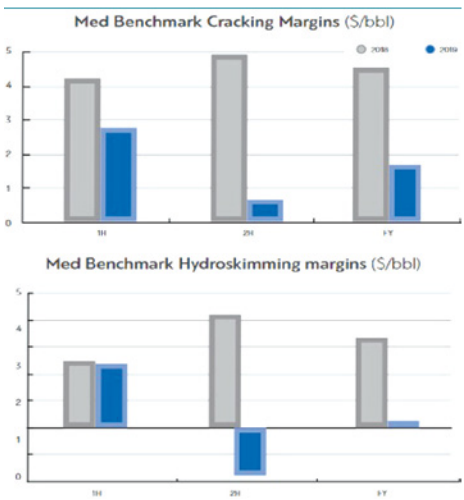
The Med benchmark cracking margin averaged at $1.7/bbl in 2019, $2.9/bbl lower y-o-y with Med Benchmark Hydroskimming margin reaching $0.3/bbl, a $3.0/bbl decrease compared to 2018. In 4Q19, refining margins were at negative levels on the back of very weak fuel oil cracks (Figures 9.49 and 9.50) [33].

Figure 9.49 **Brent - Urals Spread ($/bbl) Average 2019: $0.0/bb**



Source: HELPE

Figure 9.50 **Med Margins ($/bbl)**



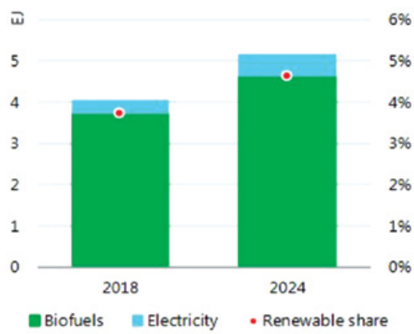
Source: HELPE

According to the IEA, European throughput is expected to start increasing from year ago levels in April 2021. After the 1.5 mb/d fall in 2020, runs are forecast to rebound by only 320 kb/d in 2021, resulting in higher imports of refined products. In March 2021, FCC margins averaged at $2.4/bbl and Hydrocracking margins at $-0.4/bbl [14].

9.1.8 Biofuels in South East Europe

As reported by the IEA, global production of biofuels in 2018 reached 154 billion litres, while renewable energy met around 3.7% of transport fuel demand in 2018, with around 4 exajoules (EJ) of consumption. Biofuels provided 93% of all renewable energy in transport, the remainder being renewable electricity. Biofuel output is likely to expand 24% (0.9 EJ) over 2019-24, while renewable electricity in transport is anticipated to increase 70% (0.2 EJ) with greater use of electrified rail as well as electric vehicles, combined with higher shares of renewables in electricity generation (Figure 9.51) [34].

Figure 9.51 **Renewable energy in transport**



Source: IEA

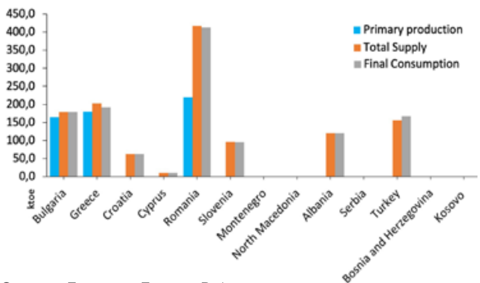
Following a 200 kb/d decline to 2.6 mb/d in 2020 amid the pandemic, global biofuels supply is expected to reach 3.3 mb/d by 2026. In the near term, a recovery in mobility and on-road transport fuel demand will underpin growth, while strengthened policies and planned capacity additions will drive gains thereafter [1]
In 2021, the biofuels market is likely to recover and approach 2019 production levels as transportation activity slowly resumes and biofuel blending rates increase. Biofuels are consumed mostly in road transportation, blended with gasoline and diesel fuels, and thus are less affected by continued depressed activity in the aviation sector [35].

According to Eurostat, total biofuels production in EU-27, in 2019, reached 33,904 ktoe, of which 20.3% was pure biogasoline, 64.7% pure biodiesel, 0.1% pure jet kerosene and 14.9% other liquid biofuels. According to the European Commission's Renewable Energy Progress Report [36], in 2018 the EU consumption of sustainable biofuels amounted to 16,597 ktoe, of which 3,905 ktoe (24%) were Annex IX biofuels[3] and 12,692 ktoe (76%) were other compliant biofuels. Most biofuels consumed in the EU constituted of biodiesel (77%) or bioethanol (16%).

[3] Annex IX biofuels" cover biofuels produced from feedstock listed in Annex IX of RED II

In SE Europe, primary production of liquid biofuels (pure biogasoline, blended biogasoline, pure biodiesel, blended biodiesel, pure biojet kerosene, blended biojet kerosene, other liquid biofuels) is detected in Bulgaria, Greece and Romania, with Romania accountable for the greatest production of 219 ktoe (Figure 9.52).

Figure 9.52 **Liquid biofuels primary production/supply/consumption in SE Europe countries in 2019**



Source: Eurostat Energy Balances

Note: For countries with zero quantities, either the energy quantity is zero, or the data are not available.

According to data derived from Eurostat Energy Balances [37], the percentage of liquid biofuels in total energy supply and final energy consumption is very small for all countries of SE Europe. Albania possesses the bigger percentage of liquid biofuel in total energy supply and final energy consumption among the SE European countries (Table 9.27).

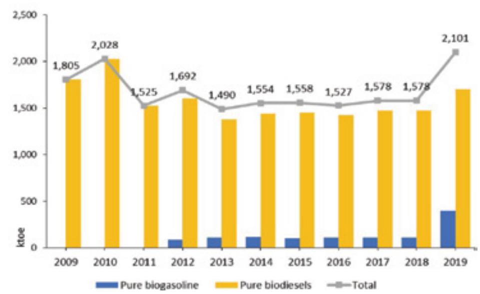
Table 9.27 **Percentage of liquid biofuels in total energy supply and final energy consumption in 2019**

Countries	**Liquid biofuel supply** as percentage of total energy supply	**Liquid biofuel consumption as** percentage of final energy consumption
Bulgaria	0.96%	1.85%
Greece	0.91%	1.25%
Croatia	0.73%	0.93%
Cyprus	0.46%	0.66%
Romania	1.27%	1.74%
Slovenia	1.44%	1.96%
Montenegro	0.00%	0.00%
North Macedonia	0.00%	0.01%
Albania	5.15%	5.85%
Serbia	0.00%	0.00%
Turkey	0.13%	0.18%
Bosnia and Herzegovina	0.00%	0.00%
Kosovo	0.00%	0.00%

Source: Eurostat Energy Balances

In South East Europe total liquid biofuels production capacity amounted to 2,101 ktoe in 2019, presenting a 14.6% increase in relation to 2009. Pure biogasoline production accounted only for 19% of the total liquid biofuels production in 2019, when the rest 81% was connected to pure biodiesels production (Figure 9.53).

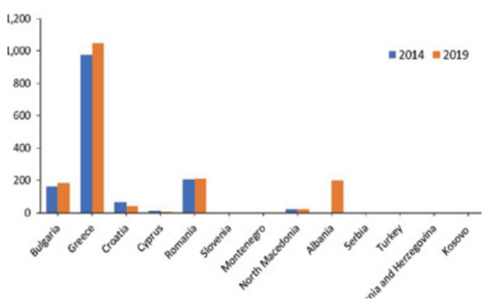
Figure 9.53 **Liquid biofuels production capacity in SE Europe**



Source: Eurostat

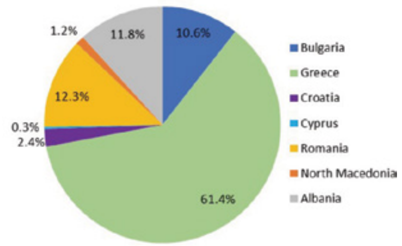
As shown in Figure 9.54 and Figure 9.55, Greece leads the way in the production capacity of biodiesels among the SE Europe countries (share 61.4%), followed by Romania (12.3%). Greece increased biodiesel production capacity in 2019 by 7.4% compared to 2014 and 81.8% in relation to 2009.

Figure 9.54 **Pure biodiesels production capacity by country**



Source: Eurostat

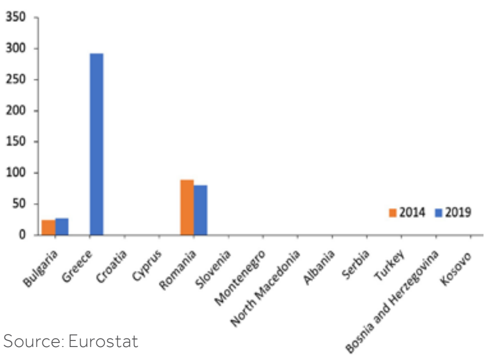
Figure 9.55 **Share of biodiesels production capacity by country in SE Europe**



Source: Eurostat

Greece produced 292,000 tonnes pure biogasoline in 2019, followed by Romania with 80,000 tonnes (Figure 9.56). It should be noted that very few countries (Greece, Romania and Bulgaria), among SE Europe countries, have a domestic biogasoline production.

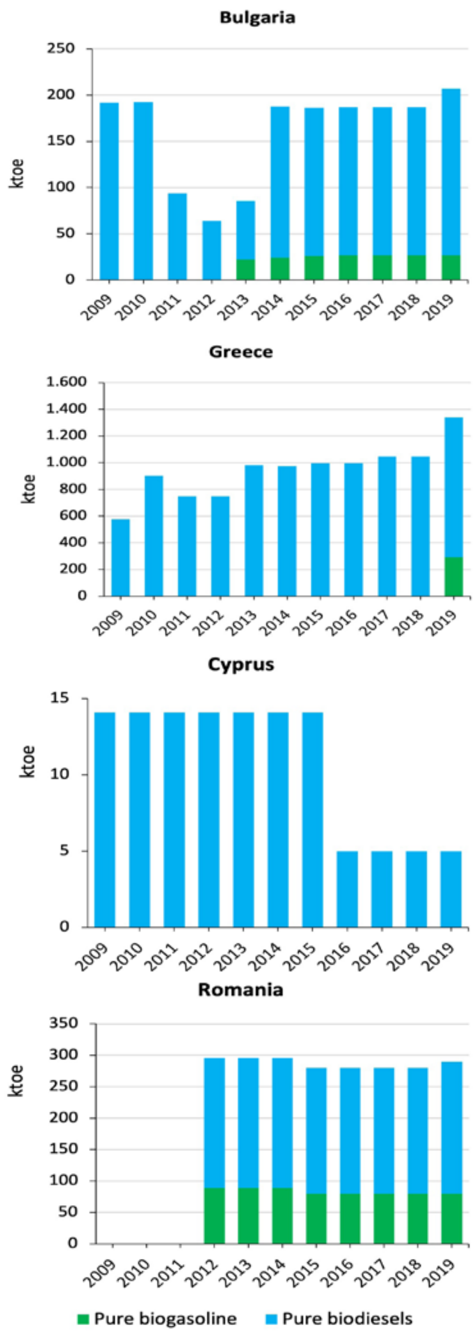
Figure 9.56 **Production capacity of pure biogasoline by country in SE Europe**



Source: Eurostat

Total production capacity of liquid biofuels in Bulgaria amounted to 207,000 tonnes in 2019, of which 87% was attributed to pure biodiesels and the rest, 13% to pure biogasoline. Cyprus has no biogasoline production and pure biodiesels production was reduced by 64.5% in 2016 compared to 2015 and remained stable for the next three years to 5,000 tonnes. Pure biodiesels account for 78% in total liquid biofuels production in Greece (Figure 9.57).

Figure 9.57 **Production capacity of liquid biofuels in selected countries of SE Europe**

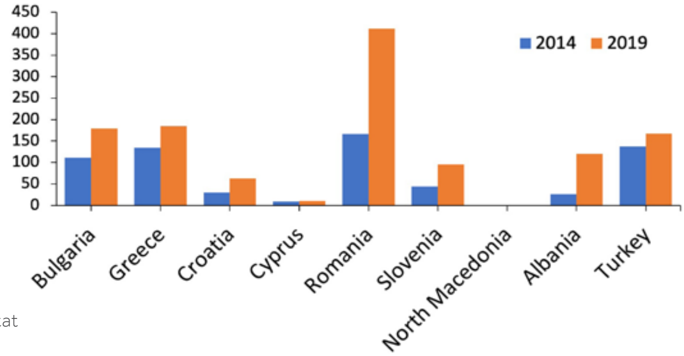


Source: Eurostat

Among SE Europe countries, Albania recorded the greatest percentage of liquid biofuel consumption growth 366%, from 2014 to 2019.

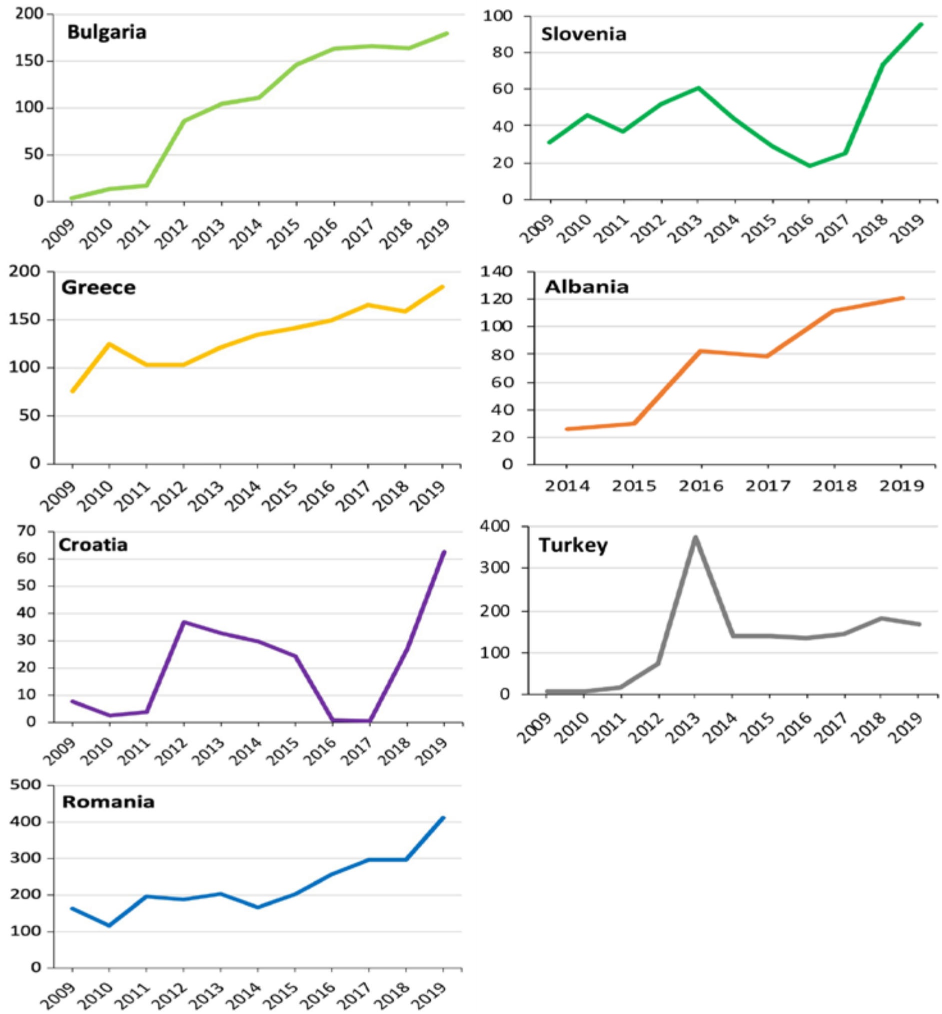
For 2019, Romania attains the greatest biofuel consumpiton for transport with 412,300 tonnes, followed by Greece with 184,700 tonnes (Figure 9.58).

Figure 9.58 **Biofuels consumption for transport in SE Europe**



Source: Eurostat

Figure 9.59 **Evolution of liquid biofuels consumption in selected SE Europe countries (ktoe)**



Source: Eurostat

According to EurObserv'ER biofuels barometer [38], the European biofuel development legislative framework was clearly defined over the long term. This has given the Member States and industry players new visibility to meet the European Union's targets. An initial step was taken in 2015 by the publication of Directive 2015/1513/EU known as ILUC to improve the integration of Indirect Land Use Change effects that impair GHG savings. The ILUC directive set a 10% renewable energy target in transport by the end of 2020 with a 7% cap for biofuels that compete with food use and an indicative target of 0.5% for advanced biofuels. However, the European Commission's new Fit for 55 package leaves room for biofuels such as renewable ethanol to help achieve Green Deal, but should better maximise their potential for decarbonising transport.

The adoption of the new renewable energies directive (2018/2001/EU) known as "RED II" that sets the roadmap through to 2030 has given the sector even more visibility. By reformulating and adding new sustainability and GHG reduction criteria and setting specific targets to biofuels originating from waste (oils or fats) or feedstocks not originating from food crops it pushes the renewable energies target in transport to 14% in 2030 (a threshold that is qualified as the "minimal share" to reach). The RED II directive provides for the share of biofuels and biogas used for transport and produced from certain feedstocks to be considered at double their energy content in the energy balance of the countries that will use them in order to achieve the assigned target of 14%.This double accounting is applied to both "advanced biofuels" (and biogas), that it defines in its article 2, that are produced from the feedstocks listed in Part A annex IX of the directive (waste and forestry residues and come from the timber sector, wastewater treatment sludge, straw, manure, raw glycerine, bagasse, algae, etc.). It also applies to biofuels (and biogas) produced with other feedstocks listed in Part B of that annex, namely used cooking oils and animal fats. However, the biofuels produced from these materials are not recognized as advanced and so are not included in the specific targets of minimum shares allotted to advanced biofuels. To enable the industrial development of "advanced biofuels", RED II provides for a specific target of 0.2% in 2022 for each Member State followed by at least 1% in 2025 and at least 3.5% in 2030 [38].

As far as the Energy Community is concerned, the implementation of the revised Renewable Energy Directive (EU) 2018/2001 (RED II) on the promotion of the use of energy from renewable sources has started to be discussed within the contracting parties. Currently, RED II is not a part of the Energy Community acquis. Renewable energy consumption in transport is generally low in the priorities of the Energy Community Contracting Parties (CP) except in Albania, which has a high share of biofuels. However, these do not fulfil sustainability requirements, and are thus not compliant with Renewable Energy Directive [39].

The implementation of the revised Renewable Energy Directive (EU) 2018/2001 (RED II) on the promotion of the use of energy from renewable sources has started to be discussed within the Energy Community. Currently, RED II is not a part of the Energy Community acquis.

Albania

Albania already has a high consumption of biofuels. However, according to Energy Community, the growing share of biofuels in fuel for transport since 2014 is all non-compliant with RED requirements and, thus, not included in the calculation of total RES-T share. Therefore, the total RES-T share is zero for all years. If the consumed biofuels had been RED compliant, the renewables share in transport would have been 13.4% in 2018, and thus the 2020 target would be achieved. However, no verification system is in place in Albania, and no information is available whether the consumed biofuels could comply with RED requirements [39]. Albania's biomass use is largely firewood utilised for various heating applications. For the production of biofuels, Albania has an operating plant that has total capacity to produce 100 kilotonnes (approximately 112 million litres) of biofuels annually. According to some estimates, this plant can produce close to the 10% biofuel blending targets by volume if operated at full capacity. However, this plant operates at 10-15% of full capacity on average and imports the vegetable oil raw material. Most of the biofuel produced is exported to Italy. Uptake in the domestic market is lagging due to a lack of enforcement of the biofuel blending obligation and the lack of sanctions for noncompliance on biofuel blending on the part of fuel suppliers. According to IRENA's CESEC study, biogas and biomass power production could reach 86 MW (495 GWh annually) by 2030, while liquid biofuels are estimated to be able to meet 8% (4 petajoules) of the transport fuel demands by 2030 [40].

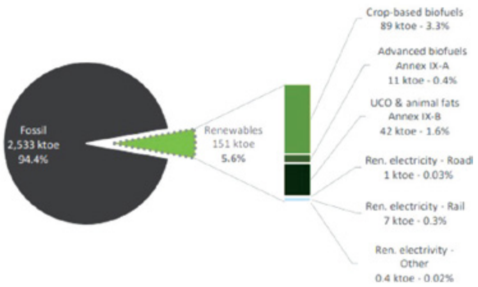
Bosnia and Herzegovina

The Energy Community Contracting Parties including Bosnia and Herzegovina have the obligation to reach binding targets for renewable energy in gross final energy consumption by 2020. For the transport sector, the binding target is a minimum 10% of renewable energy (RES-T) by 2020. Bosnia and Herzegovina will not achieve this target [39].Bosnia and Herzegovina has a share of renewable energy in transport of 0.6% through electricity consumption in rail. Biofuels are not consumed in Bosnia and Herzegovina yet. There is currently one operating biofuel plant in Bosnia and Herzegovina, producing biodiesel via esterification of vegetable oils, used cooking oils and animal fats. It is located in Srbac and is operated by System Ecologica. The plant has a production capacity of 500 tonnes per day. In the end of 2019 and beginning of 2020 there were media reports that the plant is under investigation for alleged tax fraud. Goldwater SRL have plans to develop a bioethanol plant in the region of Semberija. The ethanol is expected to be produced from lignocellulosic feedstocks through enzymatic hydrolysis and fermentation [39].

Bulgaria

Bulgaria aims at a 14.2% RES-T in 2030 with biofuels consumption reaching 2,589 GWh (222.6 ktoe), of which 1,095 GWh (94 ktoe) advanced biofuels to reach 3.5% in the energy mix. The crop-based biofuels cap will be set at 7% in 2030 while biofuels from Annex IX-B feedstock will be limited to a maximum of 1.7% (Figure 9.60, Table 9.28) [41].

Figure 9.60 **Renewables in transport in Bulgaria (2018)**



Source: ePURE

Table 9.28 **Biofuels legal framework and progress to date in Bulgaria**

What	By law (2020)	Progress to date
RED - RES-T target	10%	8.1% (2018)
Renewable mandates with multipliers	Dedicated sub-target for advanced biofuels: 0.05% in energy Petrol: 9% in volume Diesel: 6% in volume incl. 1% advanced	Annex IX-A: 0.8% in energy (2018)
Crop cap	7%	3.3% (2018)
FQD – GHG emissions reduction target for fuels	6%	2% (2017)

Source: ePURE

The Bulgarian national law for the promotion of renewable energy that was adopted in 2007, regulates the share of biofuels in transportation fuels. In order to comply with the current EU legislation, the law was amended several times according to Renewable Energy Directive (2009/28/EC). The last revision of the law was made in May 2019, in order to comply with the sustainability criteria and advanced biofuels of the revised renewable energy directive 2018/2001/EU REDII. The maximum admixture of bioethanol has remained at a fixed figure since March 2019 at 9%. Since April 2019, the share of biodiesel should be on a minimum level 6%, where 1% of this amount should be second generation biodiesel produced form algae biomass, waste biomass from households and industry, agriculture and by-products.

There was a boom of the biofuels sector in Bulgaria during the period between 2003-

2012, whereas around ten biodiesel plants and six bioethanol plants were built based on feedstocks from renewable crops (rapeseed, sunflower, wheat and maize). However, despite the fixed quota for mixing of biofuels, and due to the difficult market situation, higher prices of biofuels compared to fossil fuels and the luck of financial support (subsidies), currently very few of these plants are still existing and mainly producing biodiesel and ethanol for export in other countries.

Two are the main biofuel plants, which are still in operation:

- The biodiesel plant in Slivo Pole, 20 km eastwards from Ruse, managed by ASTRA BIOPLANT Ltd. with an annual capacity of 60,000 t of biodiesel, this accounts for 60% of the demand for biodiesel in Bulgaria. This company is also able to produce biodiesel from second-generation feedstocks, mainly from kitchen oil and remnants from the production of acid oil; however, the feedstock is mainly imported from Asia and neighboring countries (Romania and Greece).
- The bioethanol plant operated by Almagest for production of ethanol from grains is located 35 km south-west of Sofia near the town of Ihtiman. The plant has an annual capacity of 30 M litre of ethanol, which can be used for biofuel and for the production of products in the food and cosmetic industry [42].

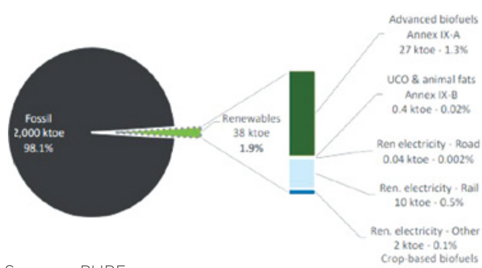
Map 9.12 **Plants in Bulgaria**

Source: ETIP

Croatia

Croatia plans to increase the RES-T to 13.2% in 2030 with biofuels accounting for 85% of the RES-T at 132.7 ktoe. Advanced biofuels are expected to contribute up to 6% of the total energy consumption in transport in 2030 whereas conventional biofuels and UCO will contribute over 2% and 3% respectively (Figure 9.61, Table 9.29) [41].

Figure 9.61 **Renewable in transport in Croatia (2018)**



Source: ePURE

Table 9.29 **Legal framework and progress to date in Croatia**

What	By law (2020)	Progress to date
RED - RES-T target	10%	3.9% (2018)
Renewable mandates with multipliers	Overall: 8.81% in energy Dedicated sub-target for advanced biofuels: 0.1% in energy	Annex IX-A: 2.6% in energy (2018)
Crop cap	7%	0% (2018)
FQD – GHG emissions reduction target for fuels	6%	-0.1% (2017)

Source: ePURE

Renewables in transport are fostered through mandatory blending targets. Authorities demonstrated their commitment by steeply increasing mandatory blending targets, reaching a substantial 8.81% in energy content for 2020 and 6% GHG emissions reduction [43]. The regulatory framework is rather complete, EU Directives are transposed in several national laws and the country has a full set of strategies, including the NREAP and a National strategy for the promotion of biofuels 2011-2020.

According to ETIP [43], production of the three domestic biodiesel sites has halted, or is in place for limited periods. According to European Alternative Fuel Observatory (EAFO), both production and consumption of biofuels have shrunken to almost zero after a promising start in the beginning of the 2010's.

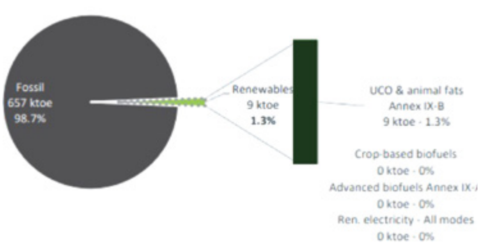
Deployment of biofuels has been initially driven by the boost in the demand for conventional biofuels with Incentives being discontinued, the sector is currently stagnating. The Envien group has capacities in Vukovar (Biodizel Vukovar d.o.o.), for the production of 35.000 t/y biodiesel from rapeseed oil, but it is unclear whether this site is still operational. The construction of a plant in the port of Ploce with an annual production capacity of 100,000 t of biodiesel from UCO and non-edible animal fat has been discontinued.

The national oil company INA, together with Faculty of Agriculture, University of Zagreb, are participating in a BBI JU funded project, GRACE "GRowing Advanced industrial Crops on marginal lands for biorefineries" of which the main goal is to produce sustainable products from miscanthus [43].

Cyprus

Cyprus plans to increase the RES-T to 14.8% in 2030. Biofuels consumption is expected to reach 1.35 PJ (32.2 ktoe) in 2030. Cyprus has increased its biofuels obligation to 7.3%, in energy, beyond 2020 (Figure 9.62, Table 9.30) [41]. Cyprus imports all of its liquid fuels from Greece.

Figure 9.62 **Renewable in transport in Cyprus (2018)**



Source: ePURE

Table 9.30 **Biofuel legal framework and progress in Cyprus**

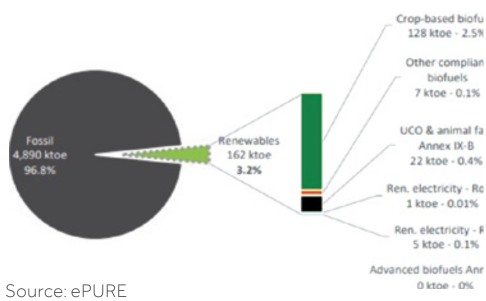
What	By law (2020)	Progress to date
RED - RES-T target	10%	2.7% (2018)
Renewable mandates with multipliers	Overall: 5% in energy	Annex IX-A: 0% in energy (2018)
Crop cap	7%	0% (2018)
FQD – GHG emissions reduction target for fuels	6%	-0.2% (2017)

Source: ePURE

Greece

Greece plans to increase the RES-T to 19% in 2030 (10% without multipliers) with biofuels accounting for 80% of the RES-T or about 371 ktoe (vs. 157 ktoe in 2018). Contribution from biofuels from Annex IX-A feedstocks is expected to reach 197 ktoe in 2030 (vs. 0 ktoe in 2018). Greece also considers raising further its blending obligations (Figure 9.63, Table 9.31) [41].

Figure 9.63 **Renewable in transport in Greece (2018)**



Source: ePURE

Table 9.31 **Biofuel legal framework and progress in Greece**

What	By law (2020)	Progress to date
RED - RES-T target	10%	4.7%(2020)
Renewable mandates with multipliers	Dedicated sub-target for advanced biofuels: 0.2% in volume Petrol: 3.3% ethanol and bio-ethers, in energy Diesel: 7% in volume. National quota of 135 Ml of biodiesel to be distributed	Annex IX-A: 0% in energy (2018)
Crop cap	7% (2020)	2.5% (2018)
FQD – GHG emissions reduction target for fuels	6%	3.7% (2018) almost 4% (2020)

Source: ePURE

Greece is committed to increasing its share of biofuels to 10% of its final energy consumption by 2030. From 17 plants in operation in 2010 the installed capacity grew to 20 biomass and 45 biofuel units in April 2019.

Biodiesel has been used to provide at most 7% of the blend volume since 2009. The binding commitments of the Greek government to replace 10% of current transport fuels with biofuels by 2020 is not achievable (currently mixing 7% biodiesel with diesel and 3.3% of bioethanol (approx. 5% per volume)translate into higher efforts within the next decade, considering that the target of RES in the transport for 2030 will be increased to more than 14% of the energy content of the fuels.

Although Greece is not developing its biogas production rapidly, its use of substrate is essentially focused on waste valorization: landfill and sewage plants are massive in the country, and exclusively based on waste. The 20 small agricultural plants use mainly agricultural residues (92% of total substrate use), and only 2% of dedicated energy crops.

Biomass and biofuels are strong markets in Greece with high growth potential. The country's agricultural sector accounts for more than 5% of GDP, more than three times the EU average of 1,8%. Companies involved in biomass and biofuels will therefore find abundant sources of raw materials", official statistics show [44].

Montenegro

With respect to the legislative procedure, Montenegro is making progress regarding the transposition of the provisions of Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources (RED), into its national regulatory framework. In May 2014, the Ministry of Economy published Montenegro's Energy Development Strategy, which defines that the basis for calculating the target in the transport sector is 3.147 GWh and 10% of RES energy is 315 GWh.

This obligation was to be fulfilled by biofuels (285 GWh), which represents about 90% of the target, while the rest would be covered by electricity used in electric vehicles and electric rail traction (30 GWh, or about 10%). As well, the Montenegrin National Renewable Energy Action Plan (NREAP) until 2020 set out an ambition to achieve a stepwise introduction of biofuels (biodiesel and bioethanol) in road transport, beginning with 3% of supply (by volume) from the end of 2014, rising to 10% in 2020. [39].

Table 9.32 **2020 and 2030 biofuel forecast consumption (according to NREAP)**

	2020		2030	
	GWL	Mil. litres	GWh	Mil.litres
Biodiesel	245	27	218	23.9
Ethanol	39.7	6.7	34.6	5.8
Total	285	33.7	252	29.7

Source: Energy Community

North Macedonia

The energy in transport is almost exclusively provided by oil and petroleum products (including LPG). There has been a very small and decreasing share of electricity and negligible amounts of natural gas and biofuels.

North Macedonia has a share of renewable energy in transport of 0.12%, mainly from electricity consumption in rail. Biofuels consumption in North Macedonia is very low, and has even gone down in recent years; biofuels do not comply with RED requirements [39]. Of the 9% overall renewables target in transport, crop-based biofuels are capped at 2%, while 7% need to be achieved by other renewable fuels. Biofuels are anticipated to contribute most to the 2030 target, while renewable electricity in rail can make growing contributions.

A total RES-T share of 10.5% in 2030 can be achieved as a combination of different options (biofuels, electricity, hydrogen). Potential contribution of biofuels to the 10.5% target is summarized in Table 9.33 [39].

Table 9.33 **Potential RES-T contribution from biofuels in North Macedonia**

		Contribution to RES-T target (%) incl. multiple counting	Amount of renewable fuel used (ktoe)
Biofuels and liquid RFNBOs	1. Crop-based biofuels in road transport	2.0%	15.6
	2. Liquid fuels produced from Annex IX B feedstocks in road transport	3.4%	13.3
	3. Liquid advanced Biofuels (based on Annex IX A feedstocks) in road transport	3.1%	11.9
	4. Liquid RFNBOs in road transport	0.58%	4.49
	5. Renewable methane in road transport	0.44%	1.7
	6. Renewable liquid fuels in shipping	0.0%	0.00
	7. Renewable liquid fuels in aviation	0.0%	0.00
	8. Renewable liquid fuels in rail	0.0%	0.00

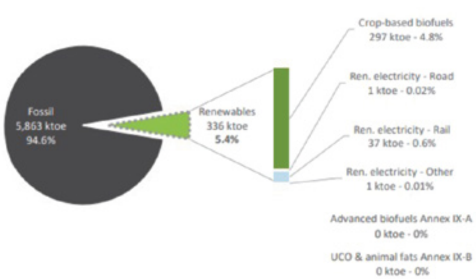
Source: Energy Community

As a latest report of Energy Community states [39], the strategy for the utilization of renewable energy sources in North Macedonia by 2020, considers the possibilities to promote the use of biofuels for transport in pure and processed form, having in mind the potentials for securing sufficient quantity of biomass of domestic origin and from import. The consumption of biofuels by 2020 is targeted to represent 10% of total fuel consumption in transport, i.e., around 48 – 56 ktoe per year, which is within the range of planned production facilities. These quantities of biofuels would replace the appropriate quantities of diesel and gasoline fuel consumption in transport.

Romania

Romania plans to increase the RES-T to 14.2% by 2030, with a crop-based biofuel consumption of 474.3 ktoe, vs. 505.7 ktoe in 2020, and a consumption of biofuels produced from Annex IX feedstocks of 63.6 ktoe, vs. 0 ktoe in 2020 (Figure 9.64, Table 9.34) [41].

Figure 9.64 **Renewable in transport in Romania (2018)**



Source: ePURE

Table 9.34 **Biofuel legal framework and progress in Romania**

What	By law (2020)	Progress to date
RED - RES-T	10%	6.3% (2018)
Renewables mandates with multipliers	Petrol: 8% in volume Diesel: 6.5% in volume	Annex IX-A: 0% in energy (2018)
Crop cap	7%	4.8% (2018)
FQD – GHG emissions reduction target for fuels	Min. 6% toward 10%	N/A

Source: ePURE

According to ETIP [45], Romania is bound to fully transpose EU Directives, which have been applied through several national laws, yet with occasional delays. The country has also steeply increased its mandatory blending targets that in 2020 were set at 8% for petrol and 6.5 % for biodiesel. The total share of RES-T is estimated at approximately 6.5%, which is below the 10% target, but yet quite relevant. Romania has installed capacities for the production of biodiesel and conventional ethanol (80 Mt/y), while an advanced Biorefinery is under construction in the south of the country.

In recent years, Romania increased its production of liquid biofuels, mostly on the account of biogas, conventional biofuel and biodiesel, with installed capacities for approximately 80 Mt/y. According to IEA, RES-T amounts to 5%, while Eurobserv'ER highlights that the country is fully compliant with the current targets with a consumption of 91.1 ktoe bioethanol and 206.2 ktoe biodiesel.

Besides existing capacities in conventional biofuels, Clariant is building a new commercial-scale plant for the production of cellulosic ethanol from agricultural residues based on the sunliquid technology. The plant with an annual capacity of 50,000 tons of cellulosic ethanol will be located in Podari near Craiova in the southwestern part of Romania. The construction started in 2018 and is expected to be completed in 2020. In order to establish a sustainable value chain, two accompanying EU projects have been funded [45].

Serbia

Since 2006, Serbia is a Contracting Party of the Energy Community, thus committing to the establishment of a single European energy market, and binding itself to aligning to EU acquis communautaire in energy related matters, including renewable energy targets as well as relevant competition and state aid regulations.

In this framework, Serbia committed to a mandatory 27% target of RES in gross final energy consumption in 2020. In June 2013, the National Renewable Energy Action Plan (NREAP) was adopted, envisaging also a significant increase RES-T, reaching 10% (from 0% in 2009). Notwithstanding the obligation to provide the transport sector with approximately 245 ktoe from RES, investments in this sector are lagging behind due to market and regulatory uncertainties. The 10% target appears unmatchable in the given timeframes: installed biodiesel capacities are currently not exploited. At present, four plants with a total annual capacity of 0.07 Mtoe exist in the country, yet none is currently producing biodiesel. According to the estimations provided in the NREAP, domestic production should have fulfilled approximately 40% of the needs in 2020 (100.000 t/y biodiesel and 17.000 t/y bioethanol). Current installed capacities are slightly lower, yet it is probable that without targeted stimulation the share of imports might be even higher that the envisaged 60% [46]. In 2019, Serbia adopted several by-laws which include measures covered by RED regarding biofuels [39]:

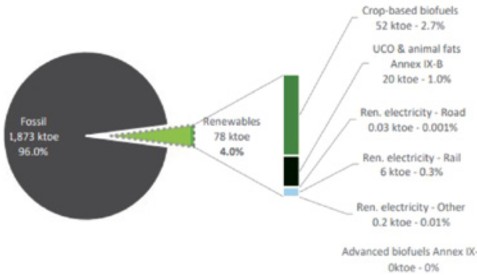
- Regulation on the share of biofuels in the market (Official Gazette of RS no. 71/2019);
- Rulebook on technical and other requirements for biofuels and bioliquids (Official Gazette of RS no. 73/2019);
- Regulation on biofuel sustainability criteria (Official Gazette of RS no. 89/2019).

However, it is defined that the Regulation on the share of biofuels in the market and the Regulation on biofuel sustainability criteria shall apply from 1st January 2021, while the Rulebook on technical and other requirements for biofuels and bioliquids already started to apply from 1st January 2020.

Slovenia

Slovenia plans to increase the RES-T target to 20.8% in 2030 with at least 11% from biofuels. The consumption of biofuels in transport is expected to reach in 2030 182 ktoe of which 89 ktoe of advanced biofuels (Figure 9.65, Table 9.35) [41].

Figure 9.65 **Renewables in transport in Slovenia (2018)**



Source: ePURE

Table 9.35 **Biofuel legal framework and progress in Slovenia**

What	By law (2020)	Progress to date
RED - RES-T	10%	5.5% (2018)
Renewables mandates with multipliers	Overall: 10% in energy Dedicated sub-target for advanced biofuels: 0.5% in energy	Annex IX-A: 0% in energy (2018)
Crop cap	7%	2.6% (2018)
FQD – GHG emissions reduction target for fuels	6%	0.3% (2017)

Source: ePURE

Based on the ETIP study [47], the growth of RES in Slovenia is proceeding at a slightly slow pace. The 2020 target of 25% has not been reached yet, with the country stopping at approx. 21%. Given the relevance of hydropower, though, it is remarkable that 61% of all renewables are "bioenergy" (1/2 of which deriving from wood), while the share of biomass in total energy consumption is 10.7%.

Despite the abundant resources, biomass and waste account for approx. 620 ktoe in TFEC over a total of 5000 ktoe (12,4%); the transport sector absorbs a very relevant 37% (1850ktoe), while biofuels in transport consumption for only 2% (despite the 7.7% mandatory blending target).

The regulatory framework concerning biofuels and bioenergy transposes relevant EU Directives and is complete. Main policy measures to foster the uptake of RES-T and particularly biofuels support mechanism, such as an excise duty relief for pure biofuels (not the blends). The mandatory blending target for biofuels is set at 7.5% in energy content, with no sub-targets. National funding is also provided through the Eco Fund. Moreover, Slovenia developed a series of strategic documents, all aiming at supporting innovation, industrial rejuvenation and green growth, even if there is not yet a specific Bioeconomy strategy [47].

Hungary

The weight of bioenergy is considerable, with 69% in RES and 10,6% in total energy. The share of RES in transport is 7.7% of which biofuels 49.8% [48].

Hungary has set a 2030 RES-T target of 14%, which will be achieved by increasing the share of crop-based biofuels to 7% and advanced biofuels to 3.5% (with multipliers) [41]. Hungrana Starch and Isoglucose Manufacturing and Distributing Ltd. is a major corn transformation company in Europe and a key player in the Hungarian food industry. The company also produces approx. 350t/y bioethanol for the transport sector.

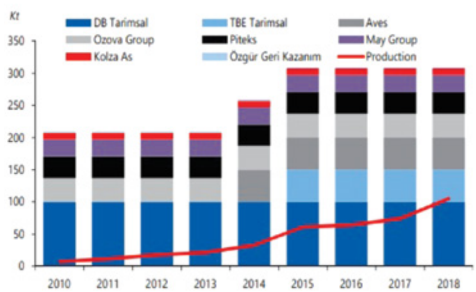
Pannonia Bio, formerly Pannonia Ethanol operates a biorefinery in Tolna County. From its beginnings as a bioethanol producer in 2012, the refinery has almost tripled in size and developed into a multiproduct facility.

Today, nutrition, health, biochemical and fuel bioproducts are manufactured as alternatives to fossil materials. Biofuels production amounts to approx. 500 mln l/y. Etanol-Line Kft's bioethanol plant started its operation in 2008 in Vácszentlászló and produces 7,300 t bioethanol. At present, the processing capacity of 60 thousand tons of maize per year. Remarkably, the facility has been financed by domestic investors. Since 2007, Envien group has capacities in Komárom (Rossi Biofuel), for the production of 50.000 t/y biodiesel from rapeseed oil and UCO [48].

Turkey

Turkey had no biodiesel blending target until 2013, when a 0.2% voluntary blend target was introduced. A tax rebate was introduced alongside the target to incentivise blending. This remained in place until 2018 when a mandatory 0.5% blending target was introduced. Turkey had 12 companies in 2018 which were licensed to produce biodiesel. However, only 8 of these had stated capacity to produce biodiesel. Annual capacity in 2018 stands at approximately 300kt, having grown by 100kt since 2013 with the opening of two 50kt plants, Aves and TBE Tarimsal in 2014 and 2015 respectively (Figure 9.66) [49].

Figure 9.66 **Biodiesel production by company, total production 2010-2018**



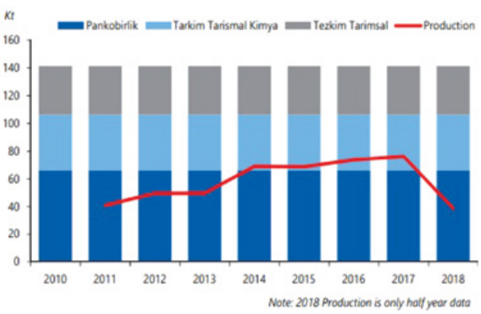
Source: Argus Consulting Services

Turkey's fuel ethanol market has been comparatively more stable than the biodiesel market. A 2% compulsory blend mandate was introduced in 2013, which was increased to 3% in 2014 which is still in place. Turkish law favours bio-ethanol obtained from domestically grown agricultural products. Extra taxation is applied if not from domestic sources.

Three companies produce fuel ethanol in Turkey, and their capacities have remained constant since 2010 (Figure 9.67). All production is currently from 1G feedstocks:

1. Pankobirlik - 66kt capacity – One of Turkey's main sugar cooperatives, produces ethanol from sugar beet syrup and molasses, plant is located in Konya.
2. Tarkim Tarismal Kimya – 40kt capacity – Produces ethanol from corn and wheat, plant is located in in Mustafakemalpaşa.
3. Tezkim Tarimsal – 35kt capacity - Produces ethanol from corn and wheat, plant is located in Adama.

Figure 9.67 **Ethanol capacity by company and production, 2010-2018**



Source: Argus Consulting Services

Map 9.13 demonstrates the clustering of Turkey' s existing biofuel plants around the key population centres in the northwest, west coast and south/southeast as well as the main agricultural regions. Close to both supplies of feedstock as well as end customers. It is thought that any new plants would be constructed within these areas as these are also the most promising areas for 2G feedstocks.

Map 9.13 **Locations of ethanol and biodiesel plants, producing and not producing, 2018**

Source: Argus Consulting Services

9.1.9 The Retail Oil Market

The retail oil market is one of the major retail market operators in SE Europe, on account of its large turnover and wide outlet network. According to Fuels Europe, the number of petrol stations that run in six (Bulgaria, Cyprus, Greece, Hungary, Romania, Turkey) out of the fourteen SE Europe countries at the end of 2019, amounted to 28,779 (Figure 9.68).

Figure 9.68 **Number of petrol stations in Europe (end 2019)**

COUNTRY	Number of petrol stations	COUNTRY	Number of petrol stations
Austria	2 733	Italy	21 700
Belgium	3 091	Latvia	606
Bulgaria	4 600	Lithuania	718
Croatia	N/A	Luxembourg	236
Cyprus	310	Malta	69
Czechia	4 008	Netherlands	4 145
Denmark	2 048	Poland	7 628
Estonia	493	Portugal	3 205
Finland	1 890**	Romania	2 250
France	11 193	Slovakia	970
Germany	14 449	Slovenia	553*
Greece	6 443	Spain	11 602
Hungary	1 998	Sweden	2 790
Ireland	1 797	United Kingdom	8 396
EU TOTAL	119 921		
Norway	1 848**		
Switzerland	3 362		
Turkey	13 178		
TOTAL NO + CH + TR	18 388		
TOTAL	138 309		

EU NON EU

Source: Fuels Europe

A brief description of SE Europe countries retail market structure follows.

Albania

There are no public companies in oil product trading in Albania. "Kastrati" a 100% private company, for years is positioned as the main wholesale and retail trader of petrol, diesel and oil products. Again, in 2018 it ranked first among top 200 Albanian companies. Its turnover for 2018 was three times higher than its closest competitor "Genklaudis".
Other private companies involved in the trade of petrol, diesel and other oil by products are; "Genklaudis", "Europetrol Durrës Albania" "Tosk Energy", "Bolv Oil", "Gega Center GKG" & "Gega Oil".

Bosnia and Herzegovina

Over 90% of the processed products in the country's two refineries are distributed in the local market. The petroleum products retail network is characterized by a large number of small retailers that own less than 5 petrol stations, and make up about 75% of the market. The highest consumption of petroleum products is in the transport sector, with motor gasoline and diesel used the most.

Greece

The greek oil industry is regulated by Law 3054/2002 (as amended) and the relevant Licensing Regulation.The following companies are active in the greek oil wholesale and retail market [50]:

- 30 petroleum marketing companies holding a type A license, with storage and trading facilities throughout Greece.
- 29 companies holding a type B1 or/and B2 license for marine or/and jet fuels, with facilities for the replenishment of ships in harbours and with stations for the replenishment of aircrafts in almost 25 airports. 16 of them also hold a type A license.
- 35 companies holding a type C license – namely license to trade LPG, with installations or/and LPG bottling plants. 5 of them also hold a type A license.
- 24 companies holding a type D license – namely a license to trade Asphalt, while 9 of them also hold a type A license.
- 1 company holding a license to transport via pipeline. The company is active in the transportation of jet fuels from the refineries to the E. Venizelos Airport.
- Approximately 6,100 service stations are established, of which 5,700 currently operate.
- There are approximately 250 heating oil resellers.

In Greece, there is one service station for every 1,750 inhabitants, while the average equivalent in the EU is one service station for every 4,500 inhabitants [50].

For the transportation and distribution of fuels many means are used, including a pipeline network, approximately 1,600 public fuel trucks, 230 private fuel trucks of the trading companies and 8.000 private small trucks for the distribution of heating oil. The sales for 2019 were 6,874,557 tonnes for the domestic market and 4,581,854 tonnes for the international market, a total of 11,456,411 tonnes[50].

Kosovo

Kosovo has an open market for oil products including imports and exports, and prices are set freely by the market. With regard to a 10% customs duty, this issue is addressed by the respective legislation in force, which fulfils obligations arising from international agreements (CEFTA, Energy Community Treaty) for the oil sector. More specifically, Law 04/L-163 and Administrative Instruction 05/2015 for commodities, subsequently amended in 2016, stipulates for customs duty is not charged and it specifies that oil products are exempt from customs duty and include: fuel oils, lubricants, bitumen, and calcinated and decalcinated petrol coke.

The market is very competitive with over 40 importers for transport fuels and many other importers of other petroleum products. The wholesale and retail prices are freely set by market forces.

North Macedonia

The purchase and sale of oil products in the Republic of North Macedonia, during 2019, was actively performed by 27 legal entities licensed for wholesale trade with crude oil, oil derivatives, biofuels and transportation fuels. In the wholesale trade, OKTA has a dominant share of 92.5 %. - In the retail trade, Makpetrol has a dominant share of 33.28 %, followed by Supertrejd with 10,77 %, and Lukoil with 10.69 %, whereas the three companies together are with 54.73 % share in the retail trade.

At the end of 2018, there were approximately 330 petrol stations in North Macedonia. Makpetrol owns 127 of these, Lukoil Makedonija 30 and OKTA 26 stations, while the remaining 147 petrol stations are privately owned by several domestic small companies [5]. The prevailing practice is that companies which possess petrol stations also participate in the wholesale market of petroleum products.

Serbia

The activity of trade of crude oil and petroleum products including biofuels and compressed natural gas and storage is operated by a large number of economic entities. Some 22 licenses have been issued for crude oil and petroleum products storage, also 51 for crude oil and petroleum products wholesale and 463 for crude oil and petroleum products retail trade. Oil imports are fully liberalized and retail prices are determined by market prices. The retail trade of petroleum products in Serbia is performed through a well-developed network of outlets which comprises 1,481 retail facilities [6].

Bulgaria

The market is fully liberalized and all downstream oil trading companies in Bulgaria are privately owned. The market is highly competitive, where small market players also have a share. The previously state-owned downstream oil company Petrol AD was privatized in 1999. The biggest players in the market either operate their facilities themselves (gas stations), or assign them to operators or franchisees.

The volumes on the wholesale market are traded by companies that are also suppliers of petroleum products. Typically, this activity is carried out directly or through other companies that perform the role of midstream players. Imported or domestically produced quantities reach the retail market (end users), either directly or through the channeling of products in the wholesale market.

The customers in the wholesale market purchase products from tax warehouses (also known as excise warehouses) for storage (storage facilities); it is mandatory for imported fuels to be unloaded and stored in these tax warehouses before they enter the retail market. Tax warehouses enjoy a special tax regime and are under the control of the Customs Agency as they are in charge of collecting excise duties, while the National Revenue Agency is in charge of other taxes such as VAT, income taxes, social and health insurance benefits, etc.

The most important market players are: Lukoil, Petrol, OMV, Shell, Naftex, Prista Oil, Hellenic Petroleum, Rompetrol, NIS Petroleum (Gazprom), Eco Bulgaria, Bulmarket DM, Vitogaz, Kalvacha Gas, Synergon Petroleum, Gastrade, INSA Oil.

The major player in the wholesale market is Lukoil Bulgaria, which is the only trader in the market. The company is vertically integrated with a refinery, petroleum products pipeline infrastructure, wholesale and retail suppliers, and located within the boundaries of the national market.

The company also, directly or indirectly, owns over 80% of the capacity of tax warehouses for storing gasoline and diesel fuels. Traders on the wholesale market, other than Lukoil, include Rompetrol, Naftex Petrol, OMV Bulgaria, and Eco Bulgaria, which engage in imports from neighbouring refineries located in Romania and Greece.

Cyprus

The Cyprus oil market is dominated by 10 local petroleum products trading companies which import and supply oil products in Cyprus for retail, industrial and commercial purposes. Three of them share more than 70% of the market share. After the cease of operation of the Cyprus Petroleum Refinery in Larnaca in April 2004, these trading companies import finished petroleum products from refineries abroad, store them at their facilities and then distribute them out to the local market through their own network of petrol stations. In 2020 the total number of petrol stations operating in Cyprus was 305.

Automotive and heating fuels are traded in Cyprus through the petrol stations located throughout the country (most of the petrol stations in Cyprus are owned by the aforementioned oil importing companies). Since the accession of Cyprus to the EU in 2004, oil products' prices are set freely, while the Minister of Energy, Commerce & Industry has the authority to set a price ceiling for specific oil products and for a specific duration in the event of emergency or during times of intense price volatility.

LPG is currently only used only for domestic, industrial, services (hotels and restaurants) and for heating purposes, it is sold both in bottles and bulk. A reduced 5% VAT rate is charged for LPG bottles.

Hungary

The Hungarian wholesale and retail oil markets are fully liberalized. The largest local market player is MOL, which is an integrated international oil and gas group. The group has also extensive upstream and downstream interests in other countries. It is active in all downstream activities, including refining, pipelines, and retail. The wholesale market is dominated by MOL and OMV, the two main regional refiners.

At the end of 2017 there were 2,077 filling stations in Hungary. According to company information, there are currently 472 MOL, 194 OMV, ca 170 Shell, ca 75 Normbenz (under Lukoil brand) (2020 May) and ca. 850 independently owned petrol service station. "There has been a number of mergers and acquisitions in the retail market in recent years. For example, in 2014, Normbenz acquired the Lukoil stations in Hungary (and in the Slovak Republic) but kept the Lukoil brand. In 2016, MOL acquired all ENI stations in Hungary, which officially became MOL property from 1 August 2016.

Turkey

In 2018, the domestic petroleum market was supplied by 97 distributors and 12,828 fuel stations, while the Liquified Petroleum Gas (LPG) market was supplied by 92 distributors and 10,701 autogas stations. The four largest distributors in the petroleum market (POAŞ, OPET, SHELL, BP) account for 65.6% of the sales and the ten largest for 84.6%. According to analyses and taking into consideration the concentration and Herfindahl-Hirschman Indexes, the petroleum market in Turkey, although competitive at retail level, has a tendency to shift to an oligopolic structure [7].

9.2 Natural Gas

9.2.1 Gas Market Development in SE Europe

Natural gas is a relatively new fuel for SE Europe, while a number of countries, especially in the West Balkans, do not yet include gas in their energy mix or they are using minimal quantities. In two key regional countries, in terms of infrastructure and consumption, gas was introduced in late 1989 in Turkey and in 1996 in Greece. But also in the case of the ex-COMECON countries in SE Europe gas was not widely used, since priority was given to much cheaper and locally available lignite. In Slovenia, gas also came late when Russia decided that the country could become a key junction for shipping gas to Italy. In this sense, gas markets in SE Europe are still undergoing a development phase. Currently, the gas sector in SE Europe faces significant challenges which are mainly related to the ongoing process of market transformation within the EU but also as a result of global developments, where the fast rise of LNG is testing market norms.

The market structure, in terms of ownership and regulation framework, being under consideration for a long time, is currently changing in many countries. The role of the state is reconsidered, and the level of privatization and liberalization of gas markets shapes the business environment in each country, creating new opportunities for market players, especially in the retail sector.

In the case of Turkey, for example, the presence of new market entities, as a result of the privatization process, illustrates the magnitude of change that the gradual introduction of competition has brought about. Elsewhere, in Greece, where the gas market is fully liberalized, we have seen a radical shift in terms of imports, now dominated by cheap LNG, and huge changes at consumer market level.

As far as the EU member states of the region are concerned and those of the Energy Community, the main challenges include reform efforts for improving the gas market model in line with EU thinking and directives, while drawbacks can be seen in the continuing dominance in many countries' public gas markets structure, the absence of market competition and the lack of diversification of gas supply.

The SE region, as defined in Chapter 1-Introduction, is a heterogeneous gas market. At the extremes it contains large mature markets (i.e., Turkey – Romania) and countries with no market at all (i.e., Albania, Montenegro or Cyprus). Apart from Romania, which is a gas producer, they were strongly dependent on a single supplier, Gazprom. Another significant barrier to market development was that most of the countries were poorly interconnected due to lack of gas infrastructure connections.

As a consequence, access to third party and diverse gas supply sources are limited. Lack of interconnectivity also hinders the completion of internal gas market requirements of the EU and leads to a high degree of dependence thus undermining the Security of Supply (SoS).

Table 9.36 **Gas Production and Consumption in Selected SEE Countries 2008-2020-2025**

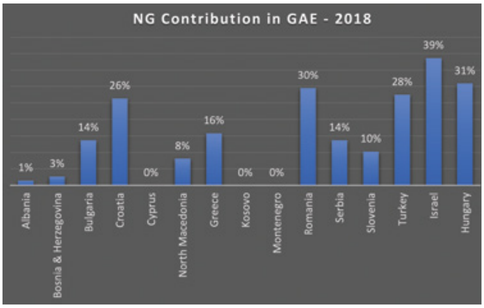
	2008		2020		2025e	
Country	**Gas Production (bcm/y)**	**Gas Consumption (bcm/y)**	**Gas Production (bcm/y)**	**Gas Consumption (bcm/y)**	**Gas Production (bcm/y)**	**Gas Consumption (bcm/y)**
Albania	0.02	0.02	0.01	0.06	0.01	0.22
Bosnia & Herzegovina	0.0	0.31	0.0	0.22	0.0	0.45
Bulgaria	0.31	3.5	0.04	3.02	0.21	4.3
Croatia	2..03	3.1	1.03	3.04	1.52	3.3
North Macedonia	0.0	4.25	0.0	0.33	0.0	0.6
Greece	0.0	0.0	0.01	5.83	0.0	6.0
Kosovo	0.0	0.0	0.0	0.0	0.0	0.0
Montenegro	0.0	0.0	0.0	0.0	0.0	0.0
Romania	11.2	16.9	9.96	11.74	10.02	14.1
Serbia	0.25	1.92	0.44	2..9	0.51	2.8
Slovenia	0.0	0.51	0.01	0.8	0.0	1.07
Turkey	1.03	36.9	0.47	48.23	0.73	56.0
Total	**14.84**	**67.46**	**11.97**	**75.76**	**13.00**	**88.84**

Source: IENE, TYNDP TSOs

The aforementioned market characteristics during the last years gradually changed (although progress has been very slow) in order to set SEE region finally on a path towards gas market integration. Currently the SE European countries (i.e. Greece, Croatia, Bulgaria, Romania, Turkey and Serbia) have well established gas markets with supplies coming primarily through imports from Russia, Iran and Azerbaijan in the case of Turkey and from Russia and Azerbaijan, in the case of Greece. Gazprom still remains a key gas supplier to most countries in the region. Greece and Turkey which have well developed LNG import and storage terminals, also import gas from Algeria, Nigeria, Qatar and other spot LNG markets. Croatia and Romania have a significant proportion of their demand met from domestic supplies. Bulgaria, Serbia and Turkey cover small percentage shares from domestic gas.

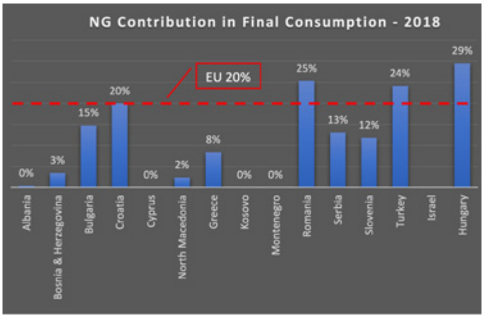
According to Figure 9.69, natural gas contribution in Gross Available Energy varies greatly among the countries of the region and overall remains low in comparison with other European countries. Concerning natural gas contribution in final energy (Figure 9.70), only Croatia, Romania, Turkey and Hungary is the same level or higher than European Union's countries average.

Figure 9.69 **Natural gas contribution in Gross Available Energy – GAE**



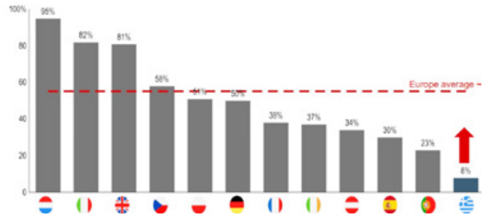
Source: Eurostat Energy Balance Sheets

Figure 9.70 **Natural Gas contribution in final consumption**



Source: ACER Market Monitoring Report 2018/2019 - Gas Wholesale Market Volume)

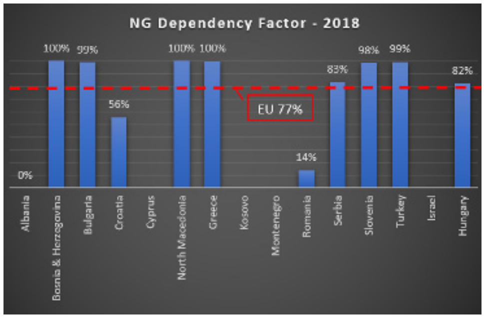
Figure 9.71 **Natural Gas in European Countries**



Source: Sedigás informe "año gasista 2016 y Perspectivas 2017"

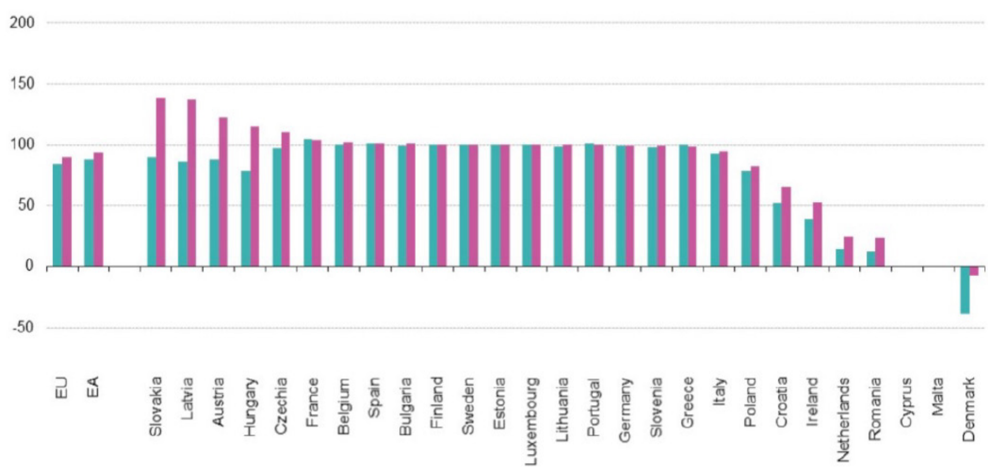
Excluding Croatia and Romania, the countries of the region are heavily dependent on imports (Figure 9.71), while Albania, Cyprus, Kosovo, Montenegro and Israel have zero-level dependency.

Figure 9.72 **Natural Gas Dependency Factor 2018**



Source: ACER Market Monitoring Report 2018/2019 - Gas Wholesale Market Volume)

Figure 9.73 **Natural Gas import dependency by country 2018-2019**



Source: Eurostat

All countries in the region (excluding Israel) are either in the European Union or in the Energy Community as Contracting Members or Observer (i.e., Turkey). In that respect there are certain obligations undertaken by the countries of the region to adopt EU gas market rules and market building ambitions. EU Energy Policy targets the removal of market development barriers by promoting and encouraging the construction of interconnectors in order to ensure that regions have access to at least 3 different gas sources (European Commission's Central Europe and Southern Europe Gas Connectivity - CESEC initiative), by implementing PCI lists, by enhancement of Gas-on-Gas competition and by creating gas markets from zero in Albania, Montenegro and Kosovo.

Even though the EU recognises the importance of interconnectivity, few interconnector projects have been built. One of the main reasons is the gas market size of the region (small economies – small TSOs regulated asset bases). On top of that, new barriers to construction of new infrastructure in the region are built due to the latest plans to exclude oil and natural gas infrastructure from EU funding in the future. The plan is a consequence of the European Green Deal[1]. It has no impact on developed gas markets (e.g., Central or Western Europe) but it is expected to have a major impact on SEE region were new infrastructure, new interconnectors and LNG terminals have to be constructed. Also, although EU Development programs have promoted gasification of Western Balkans, still remains a challenge to create gas markets after TAP commissioning.

Gazprom is the largest exporter of natural gas to the European market and consequently to SEE region. Table 9.37 includes the gas sales by Gazprom Group in 2019 in the region.

Table 9.37 **Natural gas sales by Gazprom Group in 2019**

Country	Gazprom Volumes* in bcm	Gazprom Volumes* in ktoe
Bosnia and Herzegovina	024	206
Bulgaria	239	2.055
Croatia	282	2.425
Greece	241	2.072
Hungary	1126	9.682
North Macedonia	030	258
Romania	099	851
Serbia	213	1.831
Slovenia	034	292
Turkey	1551	13.336
Total SEE	**3839**	**33.009**

* Volumes of gas sales by the Gazprom Group include, inter alia, LNG sales and gas sold under hydrocarbon exploration and production projects implemented abroad with the participation of the Gazprom Group.

Source: www.gazprom.com/about/marketing/europe/

Concerning upstream developments in the region, there are prospects in the Black Sea and discoveries located in the Romania (Chapter 5) offshore region. Probably Romania could become a small exporter in the following years, which would encourage interconnectivity even more. Also, there is on-going exploration activity locates in Bulgaria (Chapter 5) offshore region.

The outlook of gas market development for the next decade is based on different requirements on European level and SEE region level. At European level, the growing requirement for imports is caused by indigenous gas production decline in the North Sea and the Netherlands[2] (Groningen which is Europe's largest onshore natural gas field). On the other hand, gas market development in SEE region has as a main driver demand growth, based more on recovery from economic downturn.

[1] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en
[2] https://www.reuters.com/article/us-netherlands-gas-idUSKCN1VV1KE

An extra driver will be coal displacement by gas, although there are significant social costs and of course economic costs related to exchanging indigenous production for imported gas (Romania, Bulgaria, Greece and Serbia are lignite producers). Finally, and especially in the long term, possible downturn in gas demand may result due to changes in environment protection and sustainability policies, energy efficiency measures and renewables support schemes.

Gas Trading Hubs

According to IENE's working paper[3] for the prospects for the establishment of gas trading hubs in the region of SE Europe, published on June 2020, oil indexation[4] is the dominant pricing mechanism but is gradually shifting to indexation on hub market prices. Also, there is neither a market mechanism to buy or sell gas in an efficient manner, nor a price discovery mechanism to determine spot prices.

The main prerequisites for an efficient gas hub operation are the following:

- There are sufficient gas interconnections and storage facilities while gas supplies are coming from more than one source,
- There is a culture of regional energy cooperation among countries and regulators on a regional not national issue,
- Markets are really integrated and open to competition while prices are driven only by gas supply and demand,
- Local governments and regulators have already adopted the necessary legislations and regulations in accordance with Third Energy Package and ACER guidelines (including in particular provisions for TSOs independence, attractive cross-border Interconnection Agreements, effective gas balancing rules, cost reflected entry/exit tariffs etc.),
- An effective and functional gas trading electronic platform has already been in place.

The establishment and functioning of a gas trading hub require a deregulated gas market, which is not the case today in most countries of SE Europe. However, one could argue that the operation of a physical transit regional hub, such as the Belgian Zeebrugge, could also be possible, due to the flexibility resulting from the operation of the existing and planned interconnections in the region. The region could serve as a transit route for carrying Azerbaijani gas to smaller hubs that are planned in the region, as well as the Central European Gas Hub in Austria. An important issue to be addressed is where the gas hub will be based. Increased supply are prerequisites for creating a market in the region. At the moment, there are several new pipeline connections planned in SE Europe, as well as FSRU and underground gas storage facilities, with Greece, Bulgaria and Turkey having expressed a high interest in establishing a regional gas hub.

Storage will also play an important role in providing physical gas flexibility. The role of gas storage is critical as it can serve as an important flexibility tool and may affect the location of the hub, if physical. If the hub operates as a physical hub, it is possible that the TAP/IGB/IGT junction can serve as a physical hub. Map 9.14 depicts the classification of gas hubs based on 2020 AGTM trading metrics results[5].

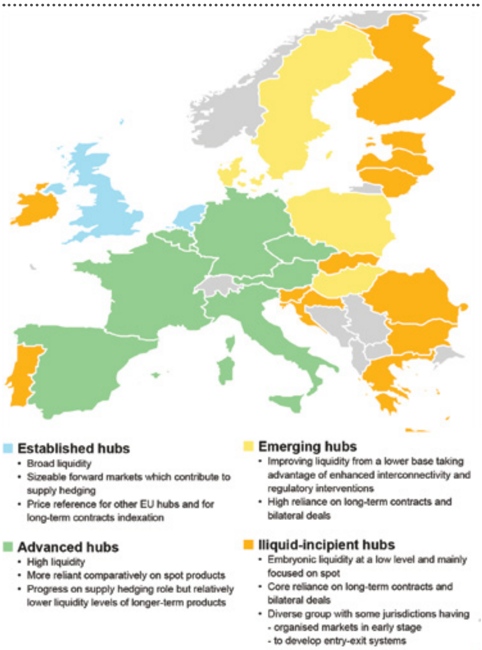
It is evident that SEE countries still have weak or no hub dynamics and continue to fall behind better performers. Most SEE countries still show a sub-optimal level of market development and higher supply-side concentration. Continuous alignment to the acquis communautaire of the EU is a precondition for enhancing market integration and cross-border trading with the EU and among themselves. In 2019, positive developments were observed in Hungary, resulting in its hub no longer being classified

[3] https://www.iene.eu/articlefiles/working%20paper%20no28.pdf
[4] Oil indexation is historical consequence of long-term contracts signed in the past.
[5] The ACER Gas Target model (AGTM) is a model for the internal gas market (IGM) developed by the Agency, NRAs and gas sector's stakeholders. In order to assess the gap between gas hubs' status and the targeted performance, the AGTM is complemented by a set of indicators, the so-called "market health" metrics and the "market participants' needs" metrics. The results of the market health metrics indicate whether gas wholesale markets are structurally competitive, resilient and exhibit a sufficient degree of diversity of supply; and the results of market participant's needs metrics indicate how liquid their gas hubs are.

as illiquid in comparison with 2018. This development is attributed to price-competitive transportation tariffs and timely implementation of Balancing Network Code. Also markets with access to LNG have the healthiest level of supply source diversification.

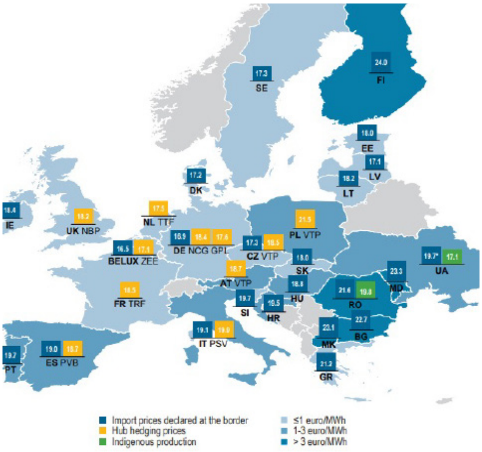
As shown in Map 9.14, most of the SEE countries gas markets remain less integrated and diversified. As a consequence, there is a gap between their sourcing gas cost and the benchmark TTF-based sourcing costs. This is quite natural since it is premature to expect equalization of the gas prices within the EU with the benchmark TTF level (or with any other hub which can in the future take the leading role as the most liquid hub) until and unless the very capital-intensive and time-consuming diversification of supply sources (three per each country at minimum) and it is impossible without upstream and infrastructure investments, which in turn are impossible without long-term contracts (LTCs). Moreover, reliance on LTCs has remained higher in the absence of sufficient upstream supply competition.

Map 9.14 **Ranking of EU hubs based on monitoring results – 2020**



Source: ACER based on ICIS Heren and REMIT data

Map 9.15 **2019 estimated average suppliers' gas sourcing costs by country and delta with TTF hub hedging prices – euros/MWh**



Source: ACER calculation based on Eurostat Comext, ICIS and NRAs from both MSs and EnC CPs

Concerning the Balkan Gas Hub[6] the main objective is to connect the Balkan Region, Central and Eastern Europe gas markets with the markets in Western Europe by constructing the required infrastructure and ensuring trading and regulatory environment, including a liquid and competitive gas exchange market. Under the agreement of the governments of Romania, Bulgaria, Greece and Serbia, the concept of the Balkan Gas Hub provides the supply of natural gas from different sources: the Black Sea (Romania and Bulgaria), the Southern Gas Corridor (Caspian region, Middle East and Eastern Mediterranean), LNG terminals in Greece and Turkey and Russian gas via Turkish stream. The shortest route to the Central European gas market is passing through Serbia. Therefore, Serbia has a key role to play in ensuring the transit of natural gas to Central Europe after its entry into the Balkan Gas Hub.

The results of the feasibility study presented in September 2019 identified the required new infrastructure for the gas hub operation and Bulgartransgaz EAD (Bulgarian TSO) is already proceeding with the next steps for implementation of the Balkan Gas Hub concept.

[6] Project of Common Interest (PCI) 6.25.4 "Infrastructure to allow the development of the Bulgarian Gas Hub Balkan Gas Hub".

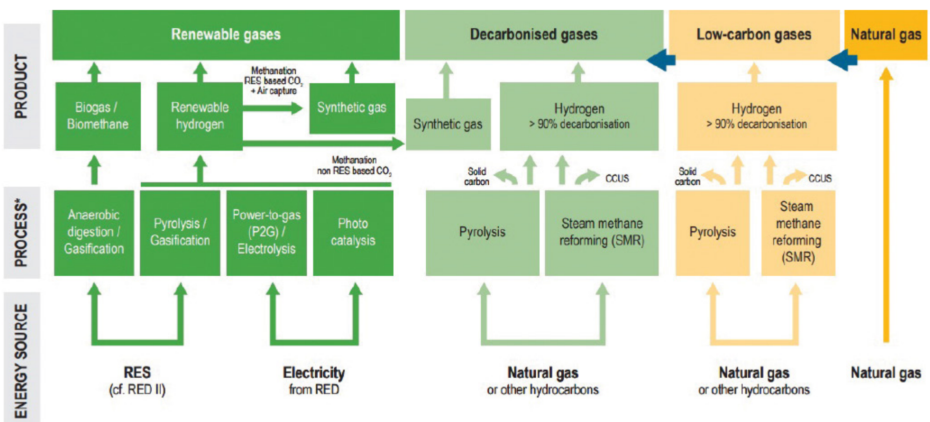
Apart from Bulgaria's hub aspirations, Romania which is well-connected has the potential to create a functioning hub in the following years.

Renewable and decarbonised gases

In accordance with the European Green Deal[7], the gas sector will need to be carbon neutral by 2050. The envisaged drop in natural gas demand will coincide with a drive to move from conventional to decarbonised and renewable gasses. This drive is primarily driven by the strict carbon emission reductions endorsed by the EU. The parallel ambitioned coupling of energy sectors' will be assisting the decarbonisation goal, as well as it shall promote energy efficiency and security of supply. Further than that, the decarbonisation shift will likely help to lessen gas import dependency. According to ACER, renewable and decarbonised gases account for less than 4% of the EU's gas consumption, the big bulk in form of biogas, as the right commercial conditions for viable production of greater volumes do not exist yet.

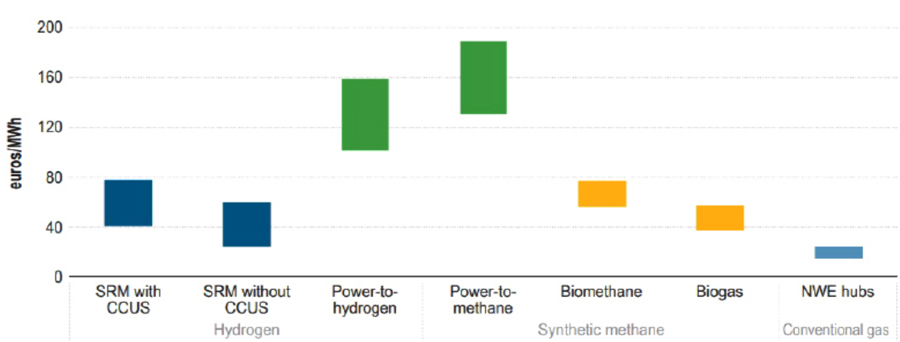
Figure 9.74 includes the main technological options for low-carbon gases production. In the absence of common objectives, countries may support different decarbonised gas technologies in the coming years, which are outlined in their respective governments' national energy and climate plans (NECPs)[8].

Figure 9.74 **Overview of renewable and decarbonised gas technologies**



Source: Gas Industry Associations for 32nd Madrid Forum, June 2019

Figure 9.75 **Illustrative overview of renewable and decarbonised gases technologies' production costs – 2019 euros/ MWh**



Source: ACER based on desk research of EC, OIES, E3G, IEA, Hydrogen Europe and other studies

[7] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en
[8] EU Member States are required under the CEP package to establish a 10-year national energy and climate plans for the period from 2021 to 2030. These plans must aim to implement the Energy Union objectives and climate targets

As Figure 9.75 reveals, the cost of low-carbon gases is 3 to more than 5 times higher than the price of conventional gas in 2019. Therefore, together with further technological developments and RES prices, a central element for determining the future competitiveness of all decarbonised energy technologies, including carbon-neutral gases, will be the price of carbon emissions under the EU ETS system. Further recognition of the value of avoided emissions would improve the use of all cleaner technologies and rise low-carbon gases presence if there are competitive enough. Therefore, reconsidering the environmental cost – and as such the pricing – of carbon emissions is one of the crucial factors that would stimulate the use of lowest-cost cleaner technologies. If carbon neutral gas managed to position among those technologies, this would lead to a meaningful increase in the production of decarbonised gasses.

When gauging the feasibility of low-carbon gas economics, the cost of upgrading the grid (but also some end-user appliances) is another critical consideration. Existing gas networks should mostly accommodate the envisaged transition, but significant adaptations and expansions may be necessary, at both transmission and distribution networks.

In addition to technical issues concerning the injection of renewable and decarbonised gases to existing and new gas infrastructure (define gas quality, blending and interoperability), the regulatory framework governing decarbonised gasses transition must clarify a number of essential and interrelated aspects (market framework, design of decarbonised gas market, network access conditions).

LNG Role in SE Europe

The key role of LNG in SE Europe is thoroughly investigated in IENE's Study Project[9].

The increasing role of LNG in SEE is underlined by 5 FSRUs under development in Croatia (Krk-on stream since January 2021), Greece (Alexandroupolis & Agioi Thodoroi), Cyprus (Vasilikos) and Turkey (Botaş Saros).

LNG market dynamics are changing rapidly over the last decade. More specifically, the global natural gas supply industry has begun to move away from its traditional integrated model where major producers developed large, often stranded gas fields, built large LNG facilities, and sold the cargoes to mainly large utilities. The major changes are:

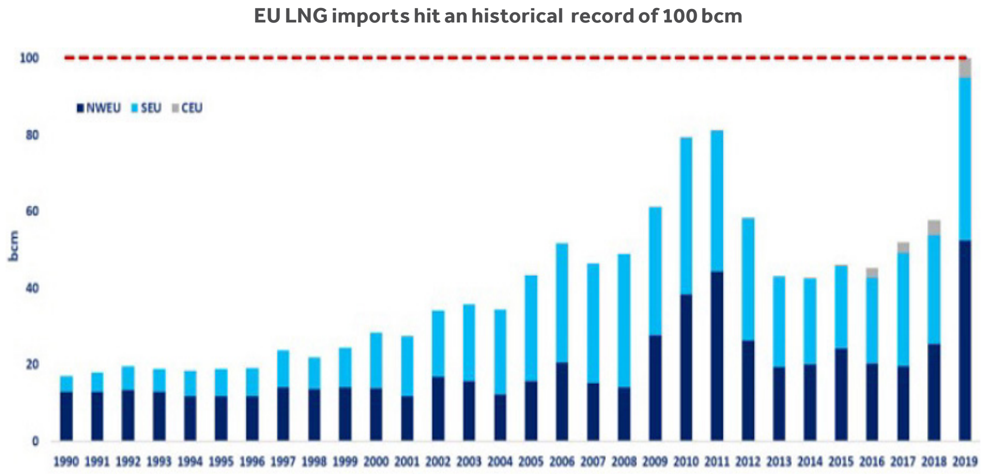
- Increased resource availability (e.g., US shale gas[10]),
- Implementation of new technologies (e.g., floating liquefaction – floating liquefied natural gas (FLNG), and floating storage regasification units (FSRUs) – Small Scale LNG) and
- New sources of demand (e.g., China and India).

Moreover, LNG usage is associated with EU priorities for diversification of natural gas sources and security of supply, climate change and lignite decommissioning.

Several new projects are in the pipeline or already commissioned (i.e. Croatia and Greece), having as main aim to enhance competition by enabling regional accessibility to LNG. In 2019 according to ACER, the slowdown of demand in the Asia-Pacific region and parts of South America and the Middle East – concurring with increasing global LNG production capacity (+13% YoY) resulted in surplus supply of LNG that found Europe to be its market of last resort, attracted by ample regasification and storage capacity and gas hub's rising liquidity. EU LNG imports hit an historical record of 100 bcm in 2019, according to Figure 9.76. The EU alone absorbed about 80% of additional LNG supply in 2019, against a lower-than-expected demand growth in Asia.

[9] https://www.iene.gr/articlefiles/gas%20supply%20in%20se%20europe%20and%20the%20key%20role%20of%20lng%20test.pdf
[10] https://ec.europa.eu/commission/presscorner/detail/el/IP_19_1531

Figure 9.76 **European Union LNG Imports**



Overflooded with LNG, European gas prices have been in a free fall through the year 2019, with TTF averaging at a 15-year low of $4.5/mmbtu. Moreover, the LNG influx has kept European gas stocks pretty full.

Obviously, the aforementioned changes affected the LNG market of SEE countries with LNG facilities. More specifically, in 2019, the SEE countries experienced an important variation in its gas supply balance. LNG deliveries rose significantly. The surge in price competitive LNG imports was driven, amongst others, by a global production surplus, with SEE countries responding to more favourable LNG price dynamics, and the diversification drives enabled by new terminals in certain countries (Croatia, Greece, Turkey).

Although the gas demand picture for 2019 was relatively favourable, the future role of natural gas in the EU is intensely debated. In order to become a carbon-neutral economy by 2050, the use of unabated natural gas would need to drastically decrease. The reduction of methane leakages across the entire supply chain is likewise seen as imperative.

LNG demand in Southern Europe is expected to grow. The rapid penetration of LNG in Southern Europe will be similar to the recent past such as Spain, Portugal, Italy, Greece and Turkey. It appears that LNG prospects in SE Europe and the East Mediterranean in particular are far better placed than they were five years ago, with new projects getting ready to progress and LNG clearly emerging as a priority fuel for several industrial consumer groups helped by lower prices and increased availability. In SE Europe, LNG seems to be a realistic alternative fuel as it increases security of supply through multiple and independent supply sources, provides the opportunity for new LNG suppliers (e.g. Australia, US, etc.) to export gas to the region, enhances pricing flexibility and safer gas transportation and can also support underperforming gas pipeline projects.

Greece and Turkey are the only countries in the broader Black Sea-SE European region which at present possess LNG gasification terminals which are well linked and integrated into their national gas systems (see the following Map 9.16). It is thus anticipated that the SE European region, from Croatia to Turkey, will play a significant role in expanding LNG trade in Europe by 2022 through the construction and operation of several new LNG regasification projects, with the prospect of feeding gas quantities into the Greek, Bulgarian, Serbian and Turkish gas systems, among others.

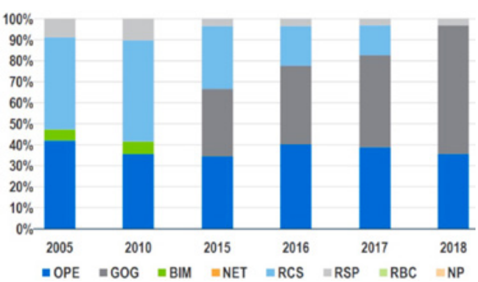
Map 9.16 **LNG Terminals in SE Europe**

Source: IENE

Price formation

According to IGU's Wholesale Gas Price Survey 2019 Edition, in SEE region (including Bosnia, Bulgaria, Croatia, North Macedonia, Romania, Serbia and Slovenia) the changes in price formation mechanisms that have taken place between 2005 and 2018 are depicted in the following Figure 9.77.

Figure 9.77 **Southeast Europe Price Formation Mechanisms**



Source: IGU

It is evident that Gas on Gas Competition (GOG[11]) increased significantly since 2005 and in amounts up to 60% in 2018. OPE (Oil Price Escalation)[12] accounts for 35% in 2018. GOG began in 2013 as Romania started liberalising domestic production pricing, moving away from RCS (Regulation Cost of Service)[13] – a process which was completed in 2018. There is also a small amount of GOG in Croatia but in no other country.

The rise in OPE in 2012 reflected a switch from BIM (Bilateral Monopoly)[14] in Bulgaria, where until 2010 there was payment in kind for transit (BIM) which then became a cash payment with the gas being purchased under the same OPE terms as the other imported gas. OPE fell back again in 2013 and 2014 as imports declined in Romania, before stabilising in 2015. 2017 and 2018 saw more declines for OPE, as Romanian imports fell. Finally, there is a small amount of RSP (Regulation Social and Political)[15] in 2018.

[11] GOG - The price is determined by the interplay of supply and demand – gas on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short-term fixed price basis and there will be longer term contracts but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category are any spot LNG cargoes, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple buyers and sellers.

[12] OPE - The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil (LNG, came from Asia), gas oil and/or fuel oil (pipeline gas, came from Europe). In some cases, coal prices can be used as can electricity prices.

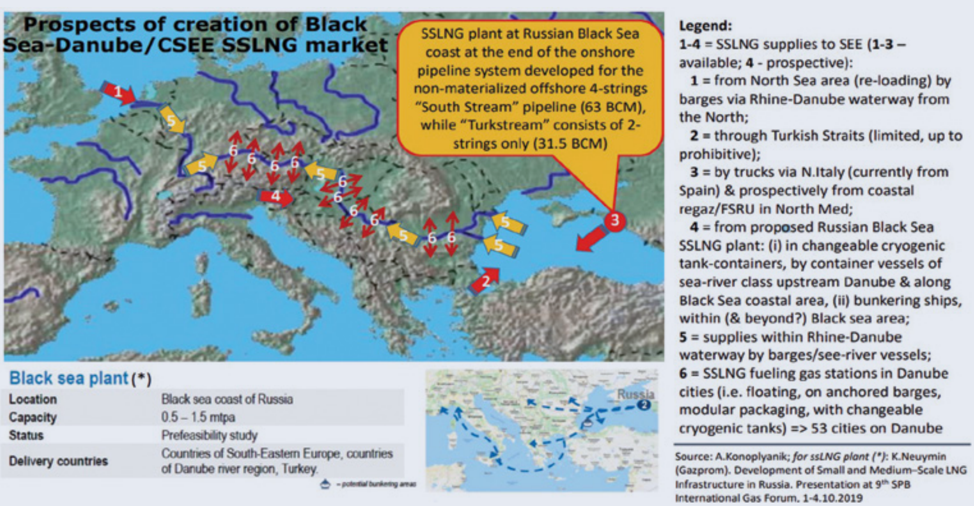
[13] RCS - The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.

The prospects of a Black Sea/Danube small-scale LNG market *

Gas supplies to South-East Europe (SEE) originate either from long-distance sources transmitted via pipeline or through re-gasified LNG injected into the gas transmission grid in various locations in SE Europe (Turkey, Greece, Croatia) but also beyond this area. This grid is rather scarce in SEE, as its density today in the countries of the region has stayed at the level of the gas grid density available in North-West Europe (NWE) as it was in late 1970s or early 1980s. So, the countries of SEE require additional gas supplies much more than the rest of the EU. However, today there is an additional option for gas supplies available to the countries in the area and they are best suited for this for a number of objective reasons. Such an option concerns off-grid small-scale LNG (SSLNG) supplies to the housing and transportation sectors, and to the small and medium business entities of the region.

Here is the vision of a prospective Black Sea/ Danube SSLNG market, which will also cover bunkering of sea and river vessels in the area.

A principal distinction between SSLNG and large-scale LNG (LSLNG) is that SSLNG, if transported and consumed at the end-use in liquid form and is not re-gasified, is delivered directly to the retail market and to the end-users, and not through the wholesale gas market. The latter is the case with pipeline gas and/or LSLNG. This is because SSLNG in such cases directly acts as the end-use energy for final consumers and no further transformation is needed prior to its end-use. In such capacity, SSLNG possesses absolute competitive advantages since it covers those market niches which cannot be covered by pipeline gas or by LSLNG.



A first competitive niche for SSLNG covers the autonomous, decentralized, off-grid gas supplies and/or electricity and heat supplies to small-medium-size users (such as local provincial towns, villages with small population in the scarcely inhabited provinces of SEE where the density of population is much smaller than in, say, NWE) based on autonomous small-scale gas-fueled power stations. Such gas-to-power stations can be developed based on a modular principle so that the broad range of electricity generation capacities can be compiled to cover the energy needs of communities of different size and population. SSLNG shall be supplied to these end-users in changeable cryogenic tank-containers which can fuel small local gas fired power stations and/or local internal municipal isolated gas grids to be developed within each individual municipality (for heating and cooking purposes). A second competitive SSLNG niche is the transportation sector (mobile energy facilities), both on-surface and water-born. Land transportation covers cargo traffic, and public transport, starting with large cities as to obtain "economy of scale" effect: buses, public works trucks, delivery of goods to retail network, etc. Water-born transportation covers bunkering of both river and sea vessels.

SSLNG fueling stations with changeable tank-containers shall be located in cities on the Danube and on the Black Sea coast (see chart). Such fueling stations can be floating, on anchored barges, and of modular packaging. Changeable cryogenic tank-containers will be delivered using one of four delivery options presented below. If placed in the cities along the Danube (a total of 53 cities) where the river is usually crossed by auto and rail routes, SSLNG can be used not only for fueling transportation needs of these cities, but for traffic passing through them.

In those consumption areas, SSLNG competes not with coal, nuclear and/or renewables (as is the case with centralized electricity production based on pipeline gas deliveries), but with petroleum products (gasoline, diesel – in transportation) and electricity (generated from renewables and/or fossil fuels) in the case of households, i.e. in cooking and heating.

There are four prospective ways/routes of SSLNG supplies to SEE (see chart). Three of those are already technically available and the fourth one can be developed based on international cooperation in the Black Sea-Danube area.

The first delivery route is from regas-LNG terminals in the North Sea area of NWE where LSLNG deliveries can be re-loaded on the barges and from there by barges (in the form of SSLNG) can be delivered via the Rhine-Danube waterway to Central Europe and SEE states. SSLNG volumes, which can in principle reach SEE from the North Sea area, cannot be large and will stay mostly in the Rhine area.

A second delivery route is from the Mediterranean area through the Turkish Straits. We have two options here: (i) LSLNG vessels enter the Black Sea and then reload to SSLNG ships to deliver to the final destination, and (ii) immediate delivery into the Black Sea area by SSLNG vessels (which can be reloaded from LSLNG, say, at Marmara regas facility).

The first option is limited (or even almost totally banned) today based on safety reasons which Turkey presented as a key obstacle to LSLNG vessels passing through Bosporus. The country is concerned that an accident or terrorist attack on an LSLNG vessel in a de facto town area presents a high risk for heavily populated Istanbul. When Turkey occasionally allows an LSLNG vessel to pass through the Bosporus, this is conditioned by many limitations which makes such supplies unstable due to the long waiting periods necessary to enter the Strait.

Two questions arise regarding this delivery route. First, whether the current prohibition for LSLNG vessels will be expanded to SSLNG vessels and LNG bunkering ships. Second, what will be Turkey's pass-through policy for the new Istanbul channel (alternative to Bosporus which is by-passing the city from the West; planned to become operational in 2023) since the Montreux Convention cannot be applied to this new route.

The third route is by trucks via Northern Italy (currently they originate in regas terminals in Spain) and prospectively from coastal regas/FSRU in North Mediterranean. This cannot be considered as a major SSLNG supply chain to SEE.

The fourth route can originate from a proposed SSLNG plant to be developed in the Russian Black Sea coast near-by a compressor station (CS) in Russkaya where the "TurkStream" offshore pipeline starts. In 2014, the earlier planned offshore pipeline "South Stream" (four pipes of total capacity 63 BCM) was changed to "TurkStream", with half the capacity of "South Stream" (two pipes, 31.5 BCM). But the onshore capacities of incoming pipelines to the Russkaya CS area are adequate as they had been built to supply the former South Stream.

This is why the incoming onshore infrastructure is available to consider building an SSLNG plant there if the export market in the Black Sea-Danube area (level of prospective SSLNG demand in SEE) can support construction of such a plant. Its architecture and logistics can be described as follows. SSLNG is to be produced and marketed in changeable cryogenic tank-containers.

They would be delivered by container vessels of sea-river class upstream Danube and along the Black Sea coastal area for onshore end-users in the area. This plant can also bunker ships within the Black Sea area (for the ships beyond the Black Sea area Marmara regas terminal would be more appropriate if bunkering facilities are made there). This means that there will be no supply monopoly of SSLNG in the area. Gazprom has made a pre-feasibility study of the LNG plant to be located at the Black Sea coast of Russia of the size 0.5-1.5 BCM, but it was looking mostly to deliver LNG beyond the Black Sea area (see chart), which is a different concept.

At the 2016 Saint-Petersburg Economic Forum (SPEF), Gazprom and OMV signed a framework agreement for the development of an SSLNG industry in the Black Sea area. The parties are currently at the pre-investment phase of the project. At the 2019 SPEF, they signed a Memorandum of Understanding regarding cooperation in the LNG field. Creation of the Black Sea-Danube SSLNG market can be a good project for broader international cooperation of the countries in the area. The central and cementing element for this can be the Black Sea Economic Cooperation (BSEC) organization and its financial vehicle, the Black Sea Trade and Development Bank (BSTDB). IENE can provide the necessary research for the project (to assess prospective demand for SSLNG, etc.) and also act as an advisor and promoter.

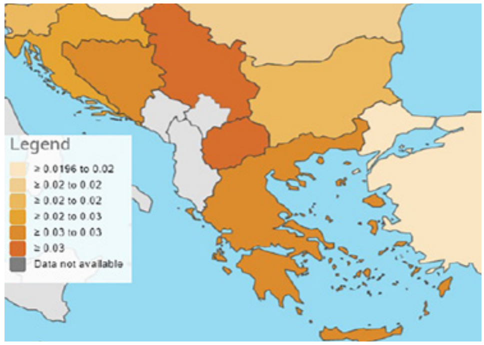
* Contributed by Prof. **Andrey A. Konoplyanik,** who is an adviser to the Director General, Gazprom export LLC, and Co-chair from the Russian side of the Work Stream 2 "Internal Markets" of the Russia-EU Gas Advisory Council, Member of the Scientific Council for System Research in Energy, Russian Academy of Sciences, and a Distinguished Research Fellow of IENE.

In the following Maps 9.17 and 9.18, Natural Gas Energy and Supply costs for household consumers and non-household consumers are illustrated for selected countries of SE Europe.

Map 9.17 **Natural Gas Energy & Supply Cost for household Consumers in Euro/KWh – 2019**

Source:Eurostat

Map 9.18 **Natural Gas Energy & Supply Cost for non-household Consumers in Euro/KWh – 2019**



Source:Eurostat

9.2.2 Gas supply and gas flows in SE Europe

The region's total gas demand is some 83 bcma with Turkey claiming the lion's share over 57% of total demand. Apart from Romania (9,5 bcm annual production in 2018), there is very little production in the region. Indigenous gas production in SE Europe (excluding Turkey), at 12.9 bcm/year, is sufficient to cover around half of current gas demand. Croatia covers 60% of its demand from domestic production and Serbia has a small production covering 20% of its demand. Regional import dependency is high and the three most gas dependent countries of the SE European region are Turkey, Bulgaria and Greece. However, not all countries in the region are gas consumers. This is especially true in Western Balkans which in the vast majority of their geographical expanse do not have any gas infrastructure.

Map 9.19 **The Trans Balkan Pipeline Network**

Source: ICIS

[14] BIM - The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically this would be one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Usually there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.

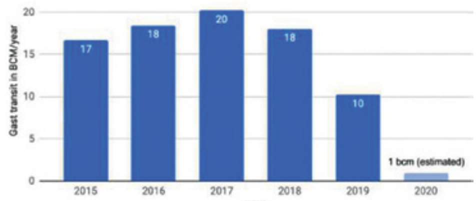
[15] RSP - The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to sell below the cost, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.

The SEE area used to be a transit region for Russian gas which entered from Ukraine and passed through the Trans Balkan Pipeline (Map 9.19) through Romania, Bulgaria, Greece, Turkey and North Macedonia. However, on January 1, 2020, the operation of the Trans Balkan pipeline started to close down as at the same time the first quantities of Russian gas started to be delivered through Turk Stream.

Whereas until the end of 2019, both Turkey and Ukraine were considered as parallel transit routes for Russian gas to eastern Europe, this assessment changed from the 1st of January 2020 as Turk Stream came onstream. On the 8th of January 2020, TurkStream pipeline was officially launched[16] and on the 27th of January 2020[17] the first billion cubic meters were delivered. TurkStream 1 and 2 which have a combined capacity of 31,5 bcma (each of the lines has a capacity of 15,75 bcma), started diverting volumes currently shipped through the Trans-Balkan pipeline across Ukraine (30 bcma capacity on the Ukrainian - Romanian border) to Turkey and further to the Balkan region and central Europe. Turk Stream 1 is dedicated to supply Turkey's market and it actually removed some 13bcma from Ukraine transit. TurkStream 2 will be fully utilized when new infrastructure is built in Bulgaria, Serbia and Hungary. Gas supplies for Bulgaria, Greece and North Macedonia also started flowing via Turk Stream at the beginning of 2020. Serbia is expected to be supplied by mid-2020 and Hungary in 2021. Although Turkey became the main supply route for Russian gas to the region, it will have little control over the supplies since the exit border capacity into Bulgaria belongs to Gazprom.

This capacity would not be booked under EU rules, since Turkey is neither an EU state, nor a contracting party of the Energy Community. Nevertheless, Turkey may have a say in negotiations with Russia over supplies via TurkStream 1, which as mentioned above, will exclusively feed the domestic market. By the end of 2019, Ukraine and Russia had signed a five-year agreement setting minimum transit flows across the Ukrainian network: 65 bcm/year for 2020 and 40 bcm/year onwards. The latter figure is half the sum of the volumes transited across Ukraine in 2019. These future supplies will be mainly targeted to Central Europe and Moldova. By contrast, the new Turk Stream will re-route Russian flows towards South-East Europe. Reverse flows, through the Trans-Balkan pipeline, were introduced in 2015 - virtual or otherwise - and have proven the value of bidirectional east-west transit. And, for the first time on August 26, 2020, Gas TSO of Ukraine carried out a south-north transmission request. It was placed by a local commodity trader, shipping natural gas up the Trans-Balkan pipeline from Greece through Bulgaria and Romania to Ukraine. The purchase was a proof of concept designed to demonstrate the technical viability of this route, even if it is not yet commercially attractive to other gas traders. The question of "whether the gas will continue to flow across the Trans-Balkan pipeline via Ukraine, the Republic of Moldova, Romania, Bulgaria, Turkey, Greece and the Republic of North Macedonia, or whether the direction will be reversed" has been asked numerous times by several gas analysts over the last years. Although we have seen a sharp decline in transmitted volumes since 2018, as shown in Figure 9.78, the Trans-Balkan pipeline can be used as an alternative route and as a back-up pipeline. It should be noted that the pipeline has not been decommissioned by its operator in anticipation of increased regional trading and the bidirectional use of its facilities.

Figure 9.78 **Gas Volumes through Trans-Balkan Pipeline**



Source: Natural Gas World

[15] RSP - The price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to sell below the cost, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.

[16] https://www.gazprom.com/press/news/2020/january/article497324/

[17] https://www.gazprom.com/press/news/2020/january/article498525/

Another major milestone achieved in the region is the commissioning of TAP at the end of 2020. TAP, which is a continuation of the TANAP pipeline crossing Turkey, is actually the last part for the development of the Southern Gas Corridor (SGC). TAP will be bringing Shah Deniz II gas to Italy, Greece and Bulgaria. There will also be a connection between Greece and Bulgaria and Bulgaria to Turkey via new interconnector pipelines (see Maps 9.29 and 9.30).

Other developments that underline supply diversification taking place in the region is the new Romania - Hungary interconnector that enabled Romania to receive additional reverse flows from Hungary since October 2019 (1,75 bcma capacity from Hungary to Romania). Also, Bulgaria acquired some small deliveries of LNG from the Greek Revithoussa terminal. Other developments concern the enabling of reverse flows from Croatia into Slovenia and Hungary, plans to interconnect Hungary and Italy across Slovenia and as referred, the linking of Bulgaria to Hungary through Serbia. Besides, the forthcoming IGB interconnector between Bulgaria and Greece will allow access to Azeri gas via TAP and also possibly to LNG. Concerning the wider SEE region, Israel is becoming a major regional exporter, especially at a time when Egypt is making efforts to absorb and offload its own gas supplies by restarting the operations of Damietta LNG plant by mid-2021[18].

The SEE region will remain a transit region and probably will become larger. The Trans Balkan Pipeline (TBP) system may be used for bidirectional flows as Russia since the start of 2020 moves gas through Turk Stream. Of course, the proviso that Turk Stream is fully utilized, is the construction of new infrastructure through Bulgaria and Serbia. Some sections of the Trans Balkan pipeline would still be covered by long-term legacy contracts which expire within the upcoming decade. These include Bulgaria's own transit contract with Russia's Gazprom which expires in 2030 and another transit contract held by Romania's Transgaz which ends in 2023.

9.2.3 Gas Markets per country

The latest natural gas developments in each country of SE Europe are described below.

Albania

There is not an actual gas market in Albania yet, as the small production associated with its oil production, is all used at the field. Natural Gas Gross Available Energy (GAE) in 2018 reached 35 ktoe, as illustrated in Figure 9.79. Natural Gas share in Total GAE still remains minimal at 1,5% in 2018. Correspondingly, there is less than 0,5% share of Natural Gas in Final Energy Consumption in 2018.

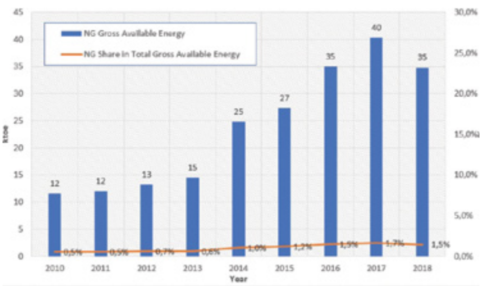
Table 9.38 **Production of the associated gas in Albania, imported LPG and balance between them**

Natural Gas plus LPG	unit	2005	2010	2011	2012	2013	2014	2015	2016	2017
Primary production (Accompanying Gas)	ktoe	9	12	12	13	15	25	27	35	37
Net imports LPG (propane plus butane)	ktoe	64	110	114	99	159	177	208	214	285
Gross available energy (Gas plus LPG)	ktoe	73	122	126	112	174	202	235	249	322
Primary production Net imports	ktoe	-55	-98	-102	-86	-144	-152	-181	-179	-248
Dependency	%	75,3	80,3	81,0	76,8	82,8	75,2	77,0	71,9	77,0

Source: EUROSTAT, 2019

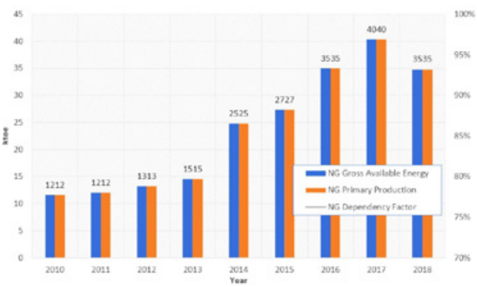
[19] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

Figure 9.79 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



Source: Eurostat Energy Balance Sheets

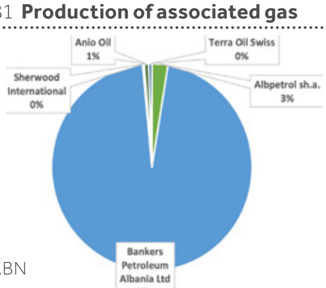
Figure 9.80 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

In 2018 natural gas production from existing oil fields reached 35 ktoe[19] which accounts only 1,5% of total domestic production of primary energy products. Albanian produces only limited amounts of associated natural gas from the existing oilfields while there is an increasing amount of LPG imported to cover the growing demand as shown by data in Table 9.38. The amount of associated gas produced in Albania in year 2019 was 69 ktoe (80 mncm) mostly produced by Patos Marinza oilfield as shown by the Figure below:

Figure 9.81 **Production of associated gas**



Source: AKBN

Shell Upstream Albania declared in May 2019 the discovery of a new oilfield in Shpiragu region in Albania[20]. The company has started the evaluation phase of the project. The initial tests have shown signs of a gas condensate discovery with high percentage of natural gas content.

Albania is a Contracting Party of the Energy Community Treaty and has continuously progressed into the adoption of the EU acquis in the energy sector. Law No. 102/2015 on the Natural Gas Sector transposes the Directive 2009/73/EC. Several other secondary legislative acts have been developed and approved and work on additional acts is progressing.

Albania's Gas Master Plan (financed through an EU grant of 1,1 million Euros), sets as key priorities the construction of the national gas network and the participation in the Ionian Adriatic Pipeline (IAP) after the construction of TAP, as well as gas connections with Kosovo and Macedonia. According to the master plan, by 2040 the average annual gas consumption of Albania will reach 1,7 bcma.

With the implementation of the National Energy Strategy (NES)[21], Albania aims to achieve penetration of natural gas in the energy sector through infrastructure investments and develop a competitive natural gas market. The NES scenario for the period 2018-2030 promotes the use of natural gas.

However, until end of 2019, there is no significant domestic infrastructural developments in the field while the Trans Adriatic Pipeline (TAP) has started commercial operation by the end of 2020 (no Shah Deniz Stage 2 gas has been contracted for delivery in Albania). With the aforementioned expected development in mind, the Albanian government established a state-owned company, Albgaz, in December 2016 to run as a combined operator for the transmission and distribution of natural gas in the country.

[20] https://ata.gov.al/2019/05/27/kerkimet-e-shell-ne-shpirag-zbulimi-i-pare-i-nje-vendburimi-te-ri-te-naftes-ne-30-vitet-e-fundit/, www.reuters.com/article/us-albania-shell-oil-idUSKCN1SU1N2

[21] Decision of the Council of Ministers No. 480, dated 31.7.2018 'On approval of the National Energy Strategy for the period 2018–30'

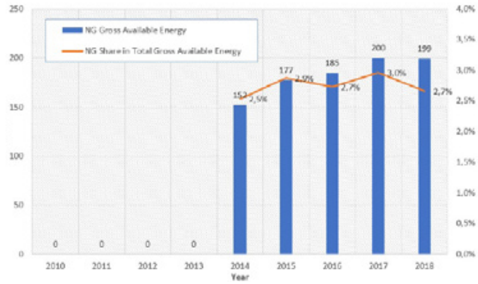
TAP is the main achievement made so far in Albania. The Host Government Agreement (HGA) between Government of Albania and TAP and the energy regulators decision (Final Joint Opinion) creates all necessary conditions for Albania to benefit from the availability of the transiting gas across the country as well as for expediting any excess gas production in the country in case of new commercial discovery. TAP has the obligation to build two exit points in Albania with capacities to be finally agreed with the Government of Albania. The locations of both exit points are already agreed at Fier compressor station and the second in Ura Vajgurore. In accordance with the joint decision of the energy regulators of Greece-Albania and Italy known as the Final Joint Opinion, TAP has the obligation to run market tests every two years and in case of positive results to make the justifiable exit capacities available. As already mentioned, the Government of Albania is making efforts to take advantage of the presence of transiting natural gas flows in the country.

Bosnia and Herzegovina

In 2017 natural gas contribution in total primary energy supply reached 200 ktoe[22] or 3% and 199 ktoe or 2,7% in 2018. The contribution of natural gas in final energy consumption in 2017 reached 149 ktoe or 4 % and 148 ktoe or 3% in 2018.

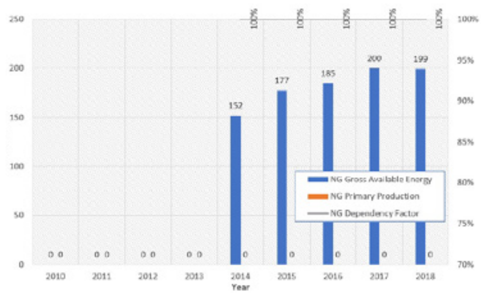
One of the reasons for the aforementioned low contribution of natural gas in final consumption, is that Bosnia and Herzegovina do not have domestic production of natural gas and does not have any installed thermal power plant gas capacities in the generation mix.

Figure 9.82 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



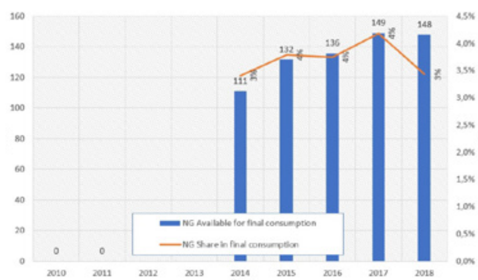
Source: Eurostat Energy Balance Sheet

Figure 9.83 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

Figure 9.84 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

[22] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

Import of natural gas to Bosnia and Herzegovina for 2018 is 199 ktoe. In final natural gas consumption of 148 ktoe, industry participates with share of 59%, households with 24% and other consumers with 17%. History of natural gas consumptions in Bosnia and Herzegovina by sector is presented in Figure 9.85.

Table 9.39 **Bosnia and Herzegovina, Annual balance of natural gas**

1000 Sm³	2016	2017	2018
Available for Supply	226.927	245.415	244.578
Production			
Import	226.927	245.415	247.012
Export			2.408
Stock exchange			-26

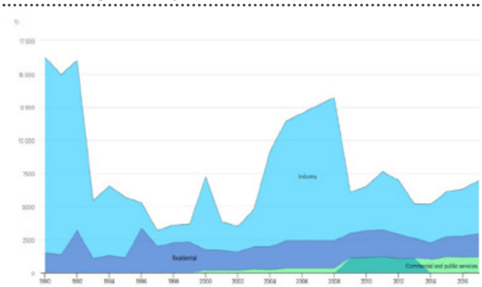
Source: Energy statistics: Natural gas, Agency for Statistics of Bosnia and Herzegovina, 2017, 2018, 2019

Table 9.40 **Consumption of natural gas by categories in Bosnia and Herzegovina**

1000 Sm³	2016	2017	2018
Consumption in energy sector	59.362	61.747	61.672
Total losses	626	542	966
Final consumption	166.939	183.126	181.940
Industry	93.344	105.198	106.984
Transport	110	1.336	2.505
Households	42.438	46.418	44.216
Other	31.047	30.174	28.235

Source: Energy statistics: Natural gas, Agency for Statistics of Bosnia and Herzegovina, 2017, 2018, 2019

Figure 9.85 **Consumption of Natural Gas in Bosnia and Herzegovina by sector in TJ**



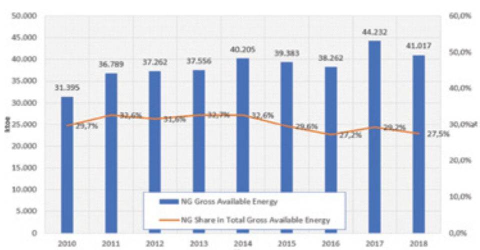
Source: IEA

Bosnia and Herzegovina's gas demand of 0,25 bcma is supplied from Russia under two acting supply contracts with suppliers Energoinvest and GAS-RES. Practically all quantities of natural gas is 100% Russian gas and therefore the country is 100% dependent on a single source and one pipeline. Russian gas is delivered via Ukraine, and then via transit routes through Hungary and Slovakia and Serbia. Concerning regulating legislation, the Energy Community introduced measures against Bosnia and Herzegovina related to non-implementation of obligations (gas legislation at state level) in accordance with the Third Energy Package (Energy Community Treaty). Last year the situation concerning further market development was still unclear and unfavourable for potential investors. The actual gas market is characterized by lack of competition and the absence in the entry of new players. Gas end users are not eligible to switch their gas supplier, and gas prices are regulated.

Turkey

In 2017 natural gas contribution in total primary energy supply reached 44.232 ktoe[23](51,441 bcm) or 29,2% and 41.171 ktoe (47,881 bcma) or 27,5% in 2018. In 2019 there was also a decrease of 9,2%, reaching 44,794 bcma[24]. The decreases of the last 2 years came in full contrast with the impressive energy demand growth of 4 - 8% between 2011 and 2016. Natural gas reached equal shares with Oil and Coal in Tukey's energy mix. In terms of final energy consumption, the share of natural gas reached 24.922 ktoe in 2017 (24 %) and 25.037 ktoe in 2018 (24%).

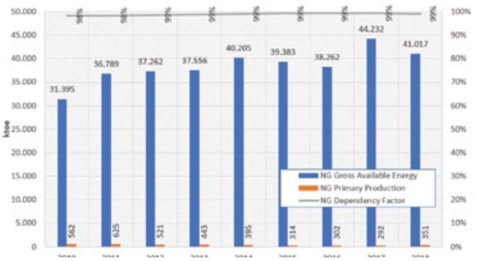
Figure 9.86 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



Source: Eurostat Energy Balance Sheets)

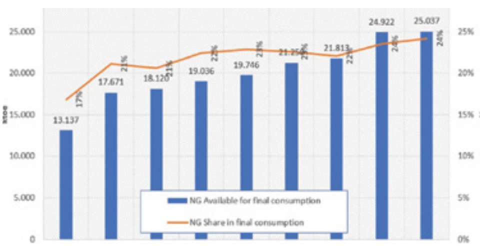
[23] Eurostat Energy Balance Sheets 2017 Data, 2019 edition
[24] EPDK

Figure 9.87 **Natural Gas Gross Primary Production**



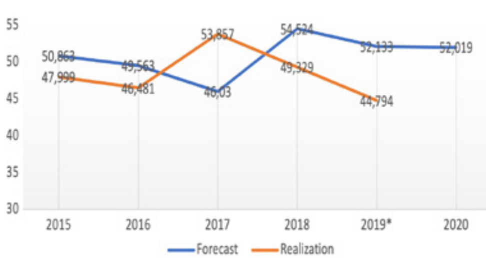
Source: Eurostat Energy Balance Sheets

Figure 9.88 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

Figure 9.89 **Natural Gas actual and forecasted consumption**



* 2019 realization is a preliminary figure subject to change.
Source: Energy Market Regulatory Authority

The basic aspects of Turkey's gas strategy as highlighted in its Strategic Plan 2015-2019 and the 11th Development Plan 2019-2023 are listed as follows:

- The share of natural gas in electricity generation will be reduced to 20,7% in 2023,
- Competition promotion by cost-based pricing will be adopted,
- In order to increase access to natural gas where appropriate, transmission and distribution networks will be increased,
- Natural gas supply security will be further enhanced,
- Underground storage capacity will be expanded to 10 bcm in 2023,
- To increase source, country and route diversification FSRU procurement and FSRU network connections will be completed,
- Deepening of trade in the Organized Wholesale Market and the start of a Future Market and Derivatives Markets to be established.

The economic downturn in the second half of 2018 and the first three quarters of 2019 may be the reason for the reduced natural gas consumption, but in 2019 the effects of the mild winter and high electricity generation from renewables and hydropower plants were also accountable. Table 9.41 shows the sectorarial allocation of natural gas consumption between years 2015 to 2018.

Table 9.41 **Natural Gas consumption in bcma**

	2015	**2016**	**2017**	**2018**
Energy & Conversion	19,313	18,493	22,593	19,933
Industry	13,966	12,600	13,372	11,988
Residential	11,000	11,701	13,515	12,702
Services	3,161	3,123	3,726	4,043
Transport	0,423	0,457	0,529	0,431
Others	0,137	0,107	0,122	0,233
Total	**47,999**	**46,481**	**53,857**	**49,329**

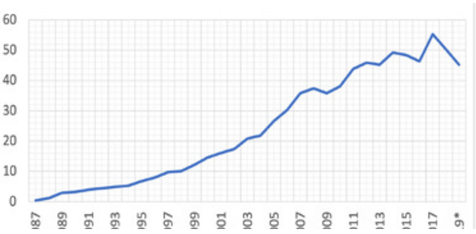
Source:Turkish Natural Gas Market Report 2016, 2017, 2018, Energy Market Regulatory Authority

In 2018, Energy & Conversion sector consumed 40% of the natural gas followed by the Households 26% and the Industry 24%. Parallel to the extension of the distribution network to remote cities of the country the share of the residential consumption surpassed the share of industry in recent years.

Turkey's natural gas imports were increasing continuously for 21 years in the period of 1987-2008. The highest import level was in 2017 with 55,250 bcma. In 2018, imports were reduced to 50,360 bcma by 8,8%. Imports reduced again in 2019 to 45,207 bcm by 10,2% (Figure 9.90).

As above mentioned, the latest decline in 2019 was caused not only by the sluggish economy but also by the weather conditions and historically high generation from hydro and renewables reaching a share of 44% in electricity generation.

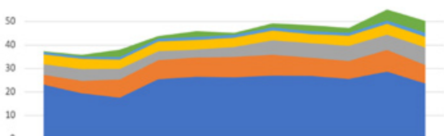
Figure 9.90 **Natural Gas Imports 1987-2019 in bcma**



* Preliminary figure may subject to change)
Source: BOTAŞ, Energy Market Regulatory Authority

The main natural gas supplier of Turkey is the Russian Federation with a share of 47% in 2018 followed by Iran 16% and Azerbaijan 15% (Figure 9.91. All three countries supply their gas by pipelines. Major LNG suppliers of Turkey with long term contracts Algeria and Nigeria had in 2018 a share of 9% and 3% respectively. The remaining 10% of the supply in 2018 came in the form of spot LNG purchases from eleven countries.

Figure 9.91 **Turkey's Natural Gas Imports by Country**



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Spot LNG	0,33	0,78	3,08	1,07	2,46	0,89	1,69	2,49	2,12	4,8	5,14
Nigeria	1,02	0,9	1,19	1,25	1,32	1,27	1,41	1,24	1,22	1,34	1,67
Algeria	4,15	4,45	3,91	4,16	4,08	3,92	4,18	3,92	4,28	4,62	4,52
Azerbaijan	4,58	4,96	4,52	3,81	3,35	4,25	6,07	6,17	6,48	6,54	7,53
Iran	4,11	5,25	7,77	8,19	8,22	8,73	8,93	7,83	7,71	9,25	7,86
Russia	23,16	19,47	17,58	25,41	26,49	26,21	26,98	26,78	25,54	28,69	23,64

Russia Iran Azerbaijan Algeria Nigeria Spot LNG

Source: Turkish Natural Gas Market Report 2018, Energy Market Regulatory Authority, 2019

Some 90% of Turkish natural gas imports were realized in the framework of long-term contracts (LTC) from Russia, Iran, Azerbaijan, Algeria and Nigeria. According to the Natural Gas Market Law BOTAŞ transferred 4 bcma of its Gazprom Contract ending in 2022 to four private importers. BOTAŞ also did not extend its 6 bcma Gazprom contract which ended in 2011. Four private importers signed new contracts of 1+5 bcm ending in 2036 and 2043.

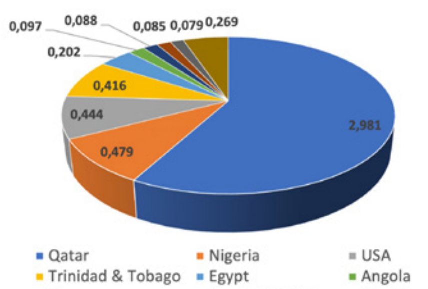
Table 9.42 **Long term natural gas import contracts**

Country	Importer	Volume	Duration	Start
Algeria LNG	BOTAŞ	4,4	30	1994/2024
Nigeria LNG	BOTAŞ	1,3	22	1999/2021
Russia*	BOTAŞ	4,	23	1998/2022
Russia*	Other**	4	23	1998/2022
Iran	BOTAŞ	9,6	25	2001/2026
Russia	BOTAŞ	16	25	2003/2028
Azerbaijan I	BOTAŞ	6,6	15	2007/2022
Russia*	Other***	1	23	2013/2036
Russia*	Private****	5	30	2013/2043
Azerbaijan II	BOTAŞ*****	6	15	2018/2033
Total			**57,9**	

* Since Jan 2020 via TurkStream (Balkan)
** Contract transfer from BOTAŞ: 2.5 bcm Enerco, 0.75 bcm BosphorusGaz, 0.5 bcm Avrasya, 0.25 bcm Shell
*** Batı Hattı
**** 2.25 bcm Akfel, 1.75 bcm BoshorusGaz, 1 bcm Kibar,
*****1.2 bcm imported by BOTAŞ for SOCAR.
Source: BOTAS, GAZID Natural Gas Importers Association

In 2018, 77,5% of Turkey's gas imports were pipeline gas and 22,5% LNG. In 2017 Turkey became the second largest LNG importer in Europe after Spain. Spot LNG imports of Turkey were growing remarkably fast during the last years. Figure 9.92 depicts spot LNG imports by country.

Figure 9.92 **Spot LNG imports by country in bcm**



Source: Turkish Natural Gas Market Report, 2018, Energy Market Regulatory Authority)

Qatar had the largest share with 58% in spot LNG imports in 2018 followed by Nigeria 9,3%, USA 8,6% and Trinidad & Tobago 8,1%. In 2007, Turkey started to re-export Azerbaijani natural gas in the framework of a 0,75 bcma Long-Term Sales Agreement to Greece.

After the build-up period 2007-2008 the exports swing around the plateau figure and reached in 2018 0,685 bcm and in 2019 0,776 bcm.

Russia's share of Turkey's natural gas imports reduced from 52% in 2017 to 33% in 2019, according to the Turkish Energy Market Regulatory Authority (EMRA). Turkey imported 45,21 bcma (out of which Russia supplied 15,19 bcm) in 2019 with liquefied natural gas (LNG) corresponding to a 29% share. The decrease of Russia's share was even steeper in the 1st semester of 2020. In March 2020, the country's LNG imports outpaced pipeline gas imports for the first time, according to EMRA, as LNG accounted for 52,5% of total gas imports in the month. The diversification of Turkey's gas supplies was promoted by the steep decrease of spot LNG prices. Gas prices dropped with increased competition and the abundance of supply on the global market.

In 2020 BOTAŞ signed a deal to buy 1,2 million tons of LNG from Total. Deliveries started at the end of 2020 and will run up to 2023. BOTAŞ' spot LNG agreements will be based on hub-linked prices instead of the oil-indexed pricing mechanism of the expiring contracts. In accordance with the latest developments of natural gas markets in SE Europe and as long-term contracts between Turkey and its existing suppliers expire in the following year, it is expected that long term contracts, based on oil price indexation and take-or-pay schemes will be replaced by gas-to-gas indexation and short and mid-term contracts, without take-or-pay obligations.

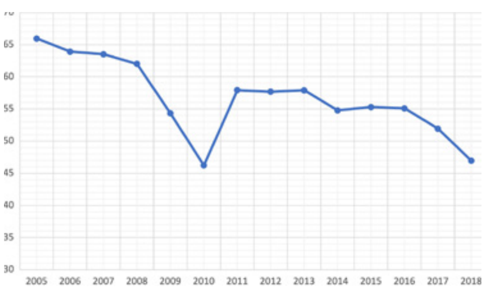
Turkey is also making efforts to develop a natural gas hub for the region. In that direction it would need Botas, the dominant player of the market, to create links with European market hubs. Also another option is developing pipeline connections through reverse flows on the Turkey-Greece interconnector pipeline, the TANAP and Turkstream, all of which would allow Turkish buyers to access pipeline gas from the rest of Europe at gas hub prices.

Despite all the aforementioned diversification efforts, Turkey is still highly dependent on natural gas imports from the Russian Federation (Figure 9.93).

Immediately after the start of natural gas imports from USSR in 1987, Turkey reinforced its diversification efforts by signing long term LNG supply contracts with Algeria and Nigeria and erecting the first LNG regasification terminal in Marmara Ereğlisi. 100% dependence on Russian gas reduced with the first LNG delivery from Algeria in 1994 and from Nigeria in 1999.

Despite Turkey starting to receive pipeline gas from Iran in 2001 and from Azerbaijan in 2007, the share of supplies from Russian Federation are still high and accounted for a 66% share in 2005, reduced with the increased spot LNG imports in 2017 and 2018 to 47% in 2018 by 19%.

Figure 9.93 **The share of Russian Gas Volumes in Turkey**

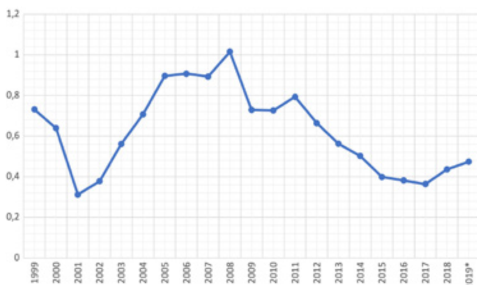


Source: Natural Gas Market 2010 Sectoral Report, Turkish Natural Gas Market Report 2018, EPDK

Domestic natural gas production reached its highest level in 2008 with 1,015 bcma. In 2018, 0,436 bcma production covered less than one percent of the demand (Figure 9.94). Also, natural gas domestic production reached 292 ktoe[25] (0,339 bcma) in 2017 and 359 ktoe (0,417 bcma) in 2018.

[25] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

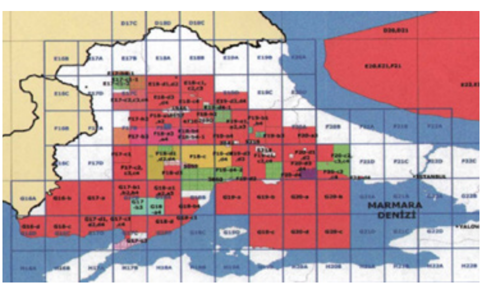
Figure 9.94 **Domestic natural gas production in bcma 1999-2019**



Source: MAPEG, 2019, Natural Gas Market Monthly Report December 2019, EPDK 2020

The recoverable natural gas reserves of Turkey were estimated at 3,8 bcma in 2018. 51% of the reserves belong to the Turkish Petroleum Corporation and the remaining 49% to other natural gas producing companies (MAPEG). 98% of the natural gas has been produced from onshore fields and only 2% from shallow depth offshore field at the Black Sea coast near Akçakoca. 97,5% of the production comes from Thrace Basin fields in European part of Turkey (Map 9.20). In 2018, 10 companies holding wholesale licence from EPDK were conducting natural gas exploration and production activities in Turkey. According to EPDK, the largest producer was TPAO with 74,5% followed by Thrace Basin Natural Gas Corporation with 12,3% and Marsa Turkey with 10,2%. According to its sector report, TPAO produced 0,405 bcma of natural gas in 2018.

Map 9.20 **Exploration and Production licences of the Thrace Basin**



Source: MAPEG

A joint venture formed by Equinor from Norway and Valeura Energy from Canada to explore formations deeper than 2.500 m in Banarlı and West Thrace licence areas made with their first deep exploration well Yamalık-1 a gas and condensate discovery (Map 9.21). The joint venture partners announced a potential of 286 bcma yet to be proved with appraisal tests. In February 2020 it was announced that Equinor will stop participating in the appraisal program and Valeura will continue[26].

Map 9.21 **Exploration areas of Equinor-Valeura Energy joint venture**

Source: www.equinor.com

In March 2020, TPAO discovered in Thrace Basin 0,200 bcma natural gas in 2 wells[27]. Next to Thrace Basin, TPAO will focus on offshore exploration in its licence areas (shown in red colour) at the Black Sea and Mediterranean. In 2018, TPAO conducted two offshore drillings. Kuzey Erdemli-1 shallow water and Alanya-1 deep sea wells at the Mediterranean.

[26] Alliance News, 4 February 2020.
[27] Daily Sabah, 12 March 2020.

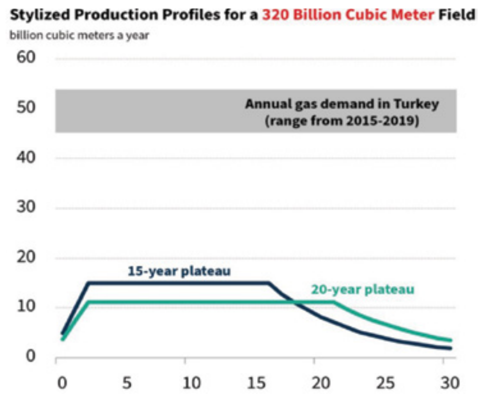
In August 2020, President Tayyip Erdogan announced Turkey has found significant gas resources in the region of Black Sea, as described in Map 9.22.

Map 9.22 **Turkey's Natural gas discovery in Black Sea**

Source: Anadolu Agency

In the summit of 2020 TPAO made a major gas discovery in the Black Sea. The discovery is on TUNA-1 location and the expected reserves are estimated at 320 bcm, which classifies the discovery in the medium-large discoveries of last decade. However, it could take at least 5 years to start production, and anticipated investment costs are between $1,5 billion and $2 billion. According to estimations by the Center for Strategic and International Studies (CSIS), a 320 bcm field would normally produce 11 to 15 bcma, as pictured in Figure 9.95.

Figure 9.95 **Estimated production profiles for Turkey's new gas discovery**



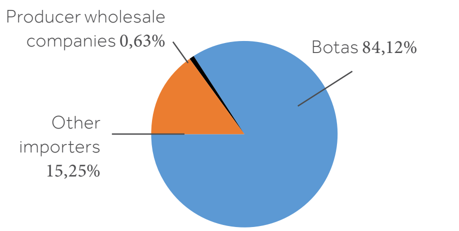
Source: : CSIS

Concerning unbundling of gas market in Turkey (Energy Community Observer) there has been limited progress, as BOTAS in still acting as the major player in transport & wholesale businesses. During 2018, natural gas was physically transported by 12 entering shippers and 22 exiting shippers in national natural gas transmission network. In addition, there were 30 entering shippers and 27 exiting shippers at virtual trade points[28]. In 2018, 0,8 bcm was transmitted by 9 licenced LNG transmission companies with LNG vehicles. (which is operating by EgeGaz and are capable of degasifying LNG while they can also load LNG onto trucks).

The basic goals of Natural Gas Market Law No.4646 (of 2001) to create competition and to avoid dominant structures have not been achieved yet. The law abolished BOTAŞ's monopoly rights on imports, distribution, sales and pricing. Account unbundling for trade, transmission and storage was realized. However, an autonomous TSO has not been established yet. BOTAŞ is at the same time TSO and the dominant player in the natural gas market. In 2018, 84,12% of 50,789 bcma total supply was realized by BOTAŞ, while 15,25% by other importers and 0,63% by domestic gas producing wholesale companies (Figure 9.96). The wholesale activities are conducted by import licence and wholesale licence holding companies. By the end of 2018 they were 54 companies with wholesale licence and 11 of them were domestic natural gas producers.

In 2018, 8 companies with an Import licence conducted wholesale activities. Those are BOTAŞ, Shell, Avrasya Gaz, Enerco, Kibar, Batı Hattı, Akfel and BosphorusGaz. From 47 Spot LNG Licence holders 16 realized wholesale activities and only two, BOTAŞ and Egegaz imported spot LNG. The remaining traded with domestic gas.

Figure 9.96 **Share of importers and domestic natural gas producers in total supply in 2018**



Source: : : Turkish Natural Gas Market Report 2018, Energy Market Regulatory Authority, 2019

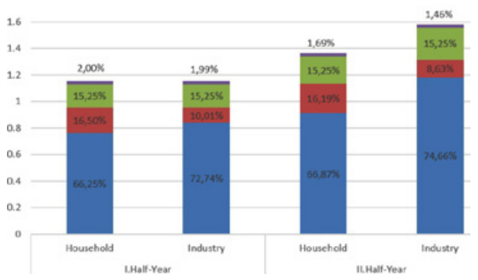
After publication of the Regulation on Wholesale Natural Gas Market in March 2017 and its Operating Procedures and Principles in September 2019 in the Official Gazette, online testing of the Spot Natural Gas Trade System was launched on 1 April 2018. On 1 September 2018, Organized Wholesale Natural Gas Market OTSP at the Energy Exchange of Istanbul, EPİAŞ started. OTSP allows the users of the natural gas transmission system to trade and to eliminate their imbalances on the basis of a continuous trade[29]. Table 9.43 summarizes the first four months of market activity in the OTSP.

Table 9.43 **Organized Wholesale Natural Gas Market**

Country	Number of offers	Number of matches	Volume of matches	Transaction value
Sept-Dec 2018	3.626	2.450	0,587	890,1

Average Unit Prices of Natural Gas Sold by Distribution and Supplier Companies to Household and Industrial Consumers was in the first half of 2018 around 1,15 TL/m³ and increased in the second half of the year to 1,36 TL/m³ for households and 1,78 TL/m³ for industry. Final sales price includes System usage cost, Value Added Tax VAT and Special Consumption Tax SCT (Figure 9.97).

Figure 9.97 **Breakdown of Natural Gas Price for Household and Industrial Consumers by Distribution and Supply Companies in 2018**



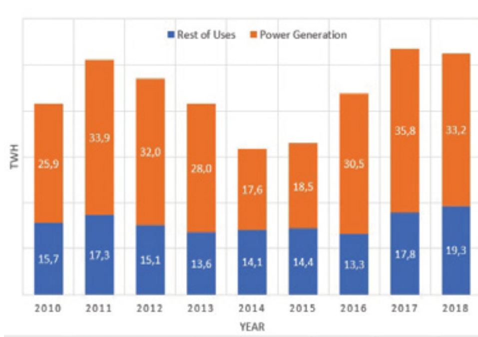
Source: Turkish Natural Gas Market Report 2018, EPDK

Greece

Over the last two years, gas demand in Greece has recovered strongly, following the prolonged economic crisis of 2010-2018 and approached 5 bcma in 2017 and 2018. Gas demand reached the highest level since the introduction of the natural gas in the energy mix in 1996. In comparison with the majority of the SE European countries, Greece has the most diverse supply.

In 2017 natural gas contribution in total primary energy supply reached 4.204 ktoe[30] or 16% and 4.117 ktoe in 2018. Natural gas domestic production reached a trivial amount of 9 ktoe in 2017, as imports – and therefore dependence accounted for 100% of the total volumes of gas consumed in Greece.

Figure 9.98 **Natural Gas Demand 2010-2018**

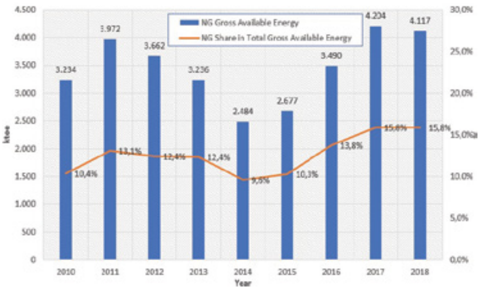


Source: Regulatory Authority of Energy

[30] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

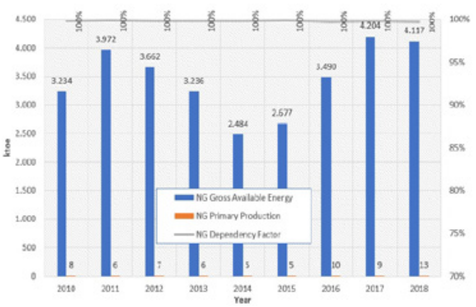
[31] DEFSA Natural Gas Annual Data 2019

Figure 9.99 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



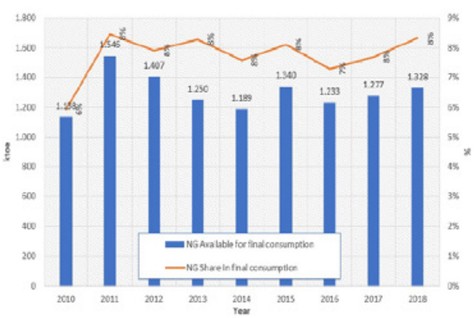
Source: Eurostat Energy Balance Sheet

Figure 9.100 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

Figure 9.101 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**

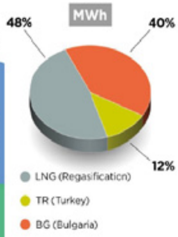


Source: Eurostat Energy Balance Sheets

In year 2019 Greek Natural Gas Market seems to have fully recovered after a 10 - year period of financial crisis and recession, as Natural Gas annual consumption reached 4.936 ktoe[31] which is the highest annual consumption since Natural Gas was introduced in Greek energy mix.

Figure 9.102 **Natural Gas Annual Data 2019**

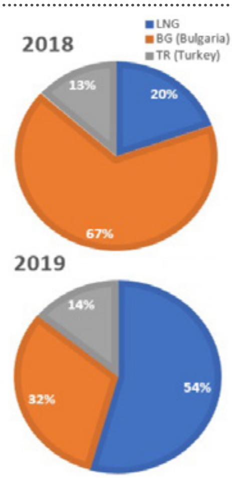
	MWh	Nm³
Natural Gas Consumption	57.407.326	4.943.457.468
Natural Gas Imports		
LNG (Regasification)	31.008.180	2.635.382.903
TR (Turkey)	8.108.942	695.244.866
BG (Bulgaria)	25.667.513	2.261.454.873
Natural Gas Exports		
BG (Bulgaria)	7.701.872	678.579.018



Source: DESFA

Power generation remains the basic demand driver in Greece as it corresponds to more than 60% of total demand. The contribution of power generation is expected to increase even more in the following years in accordance with the National Energy & Climate Plan (NECP) and the government's decision to eliminate all coal use in the country's energy system by 2028. In addition to a 826 MW Natural Gas CCGT powerplant which is under construction in Voiotia by Mytilineos Group, another two Natural Gas CCGT powerplants (662 MW in Alexandroupolis by DAMCO and 826 MW in Thessaloniki by Elpedison) were expected to reach FID by the end of 2020. In contrast with the previous years and especially 2018, most of Natural Gas imports in 2019 (54%) were delivered via LNG through the Revythoussa LNG Terminal, 32% were imported via pipeline from Russia and 14% from Turkey (Turkish Basket).

Figure 9.103 **Natural Gas Sources Contribution 2018-2019**



Source: DESFA

The remarkable increase of LNG imports is mainly attributed to the following reasons:

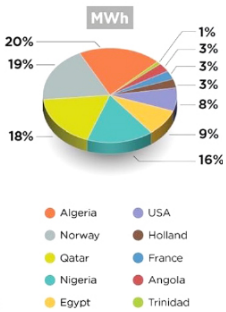
- Commissioning of the expanded facilities at Revythoussa LNG Terminal following the 2nd Upgrade Phase,
- Plummeting of LNG spot prices in comparison to 2018.

The following figure depicts LNG countries of origin during 2019 according to DESFA data.

Since 1996, when Public Gas Corporation (DEPA) was the country's sole importer of Natural Gas, the wholesale market has been liberalized and during the period 2013-2019 there has been a substantial increase in active Transmission users (especially at the GR/BG interconnection point) and LNG users according to Figure 9.105. According to RAE, 25 NNGTS Users were enlisted in the NNGTS Registry in December 2019.

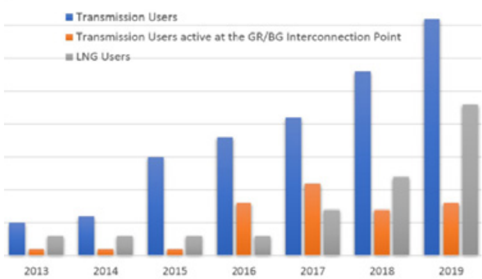
Figure 9.104 **LNG imports by country 2019**

COUNTRY	MWh	Nm³
Algeria	6.166.541	513.098.451
Norway	6.085.509	514.448.639
Qatar	5.592.037	483.373.246
Nigeria	4.931.177	409.092.592
Egypt	2.794.460	244.240.665
USA	2.502.578	217.837.201
Angola	1.009.032	85.470.978
France	1.003.672	85.640.392
Holland	929.896	78.975.390
Trinidad	273.795	24.319.296
TOTAL	**31.288.697**	**2.656.496.850**



Source: DESFA

Figure 9.105 **Number of active Transmission & LNG Users 2013-2019**



Source: DESFA

Table 9.44 **Base case demand estimation for natural gas – NECP Adjusted scenario**

	PP n.g. demand	Other Consumers		Interconnection Points - exports	NNGTS total
		Customers connected to HP network	Distribution Networks		
2021	3.371	816	1.065	350	**5.602**
2022	2.868	817	1.132	350	**5.167**
2023	3.213	874	1.169	430	**5.687**
2024	3.544	878	1.298	505	**6.225**
2025	3.459	924	1.334	635	**6.352**
2026	3.284	928	1.366	710	**6.289**
2027	3.060	928	1.402	800	**6.190**
2028	2.962	932	1.441	800	**6.134**
2029	3.001	929	1.467	800	**6.196**
2030	2.967	929	1.499	800	**6.195**

Source: DESFA

Transactions in Greek Wholesale Natural Gas Market are based on bilateral contracts between suppliers and eligible customers either via a Virtual Trading Point or by physical delivery. Also, during the years 2017-2019 a Natural Gas Release program was implemented by incumbent DEPA. It must be noted that according to RAE, DEPA's import share was reduced to 42% in 2019 from 72% in 2018. Also, DEPA's sales share bottomed to 33% in 2019 from 58% in 2018. Apart from the incumbent, other major players that emerged in the period 2017-2019 include Mytilineos Group, Elpedison, PPC, Heron, HELPE and Motoroil Hellas. According to the latest planning of Hellenic Energy Exchange, a natural gas Trading Platform will be implemented in 2021, establishing a Gas Spot Market.

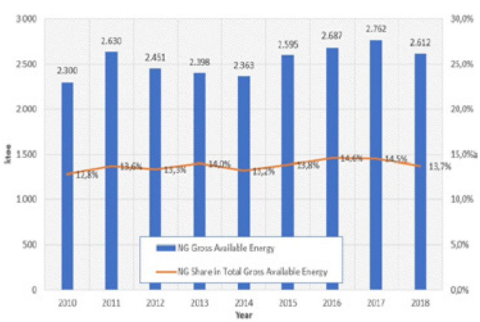
Capacity at the Kulata-Sidirokastro border point between Bulgaria and Greece is partially booked by Gazprom until 2027 as it has long-term supply agreements with three companies in Greece. However, there is capacity available for third party access from Bulgaria to Greece as well as in the opposite direction. The available capacity is booked in line with EU rules and the ENTSOG calendar. The Retail Natural Gas Market has been fully liberalized since 1st of January 2018, as all residential customers became eligible. By the end of year 2018, Natural Gas Hellenic Energy Company (ex EPA Attikis) and ZeniΘ (ex EPA Thessalonikis – Thessalias), remained the incumbent suppliers with 26,4% and 71,01% shares in respect to connections respectively and 35,75% and 46,81% shares in respect to consumption respectively. Other retail suppliers that gained the largest market shares from the incumbents, were Mytilineos Group, Heron and NRG Trading House (Motoroil Group).

According to DESFA's NNGS Development Study for the years 2021-2030, natural gas demand is expected to reach 6,195 bcma in 2030 (Table 9.45). However, according to independent analysis these are considered highly conservative estimates. IENE for one estimate that given the fast pace of the country's decarbonization programme gas consumption is most likely to reach 7,0-8,0 bcm by 2025. It is worth mentioning that during the current period, the largest project in Europe regarding the extension of gas distribution networks in 34 cities is being carried out in Greece by the Public Gas Distribution Networks (DEDA) SA. The project involves the construction of 1,860 km of distribution networks and service lines and will be completed in 2024. The networks will be installed in areas where biomethane can be produced from biomass, injected and distributed in the new networks as a blend with natural gas. The same company (DEDA) will start in 2022 the construction of non-interconnected distribution networks in major cities of Western Greece, which will be supplied by SSLNG technology. It is probably the first time at European level that distribution networks of cities with almost 200,000 inhabitants (e.g. Patras) will be supplied by implementing the SSLNG technology.

Bulgaria

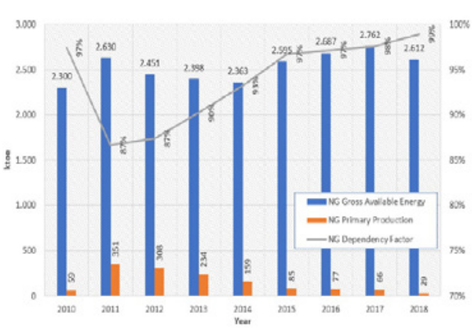
With the exception of the period 2009-2010, when demand fell by one-third due to the economic crisis, natural gas consumption has been steady in the 3,0 to 3,5 bcma range for the last 20 years. Like many markets in the region, demand shows high seasonality, which is managed by storage operations through the Chiren UGS facility and also by some import flexibility. With insignificant domestic production, supply in 2019 is over 95% met by Russian imports. In 2017 the contribution of natural gas in the total primary energy supply reached 2.762 ktoe[32] or 15% and 2.612 ktoe in 2018. Natural gas domestic production reached 66 ktoe in 2017 and 29 ktoe in 2018. Natural gas imports correspond to 94% of total gas supply. Natural gas had an almost constant share of just under 14% in Gross Inland Consumption during 2014-2018.

Figure 9.106 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



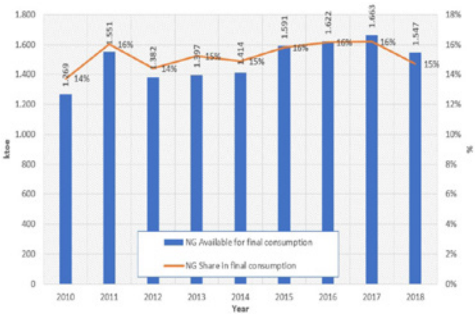
Source: Eurostat Energy Balance Sheet

Figure 9.107 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheet

Figure 9.108 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

About 32% of the natural gas in the country is used for electricity and heat generation. The non-energy use of natural gas in the chemical industry accounted to around 8% of gross inland consumption of natural gas.

Natural gas consumption for electricity and heat had been declining since 2011 due to the lower demand by the industrial sector, however, with economic activity picking up pace since 2014, consumption has increased slightly in recent years. Only 3,5% of the natural gas is consumed by households.

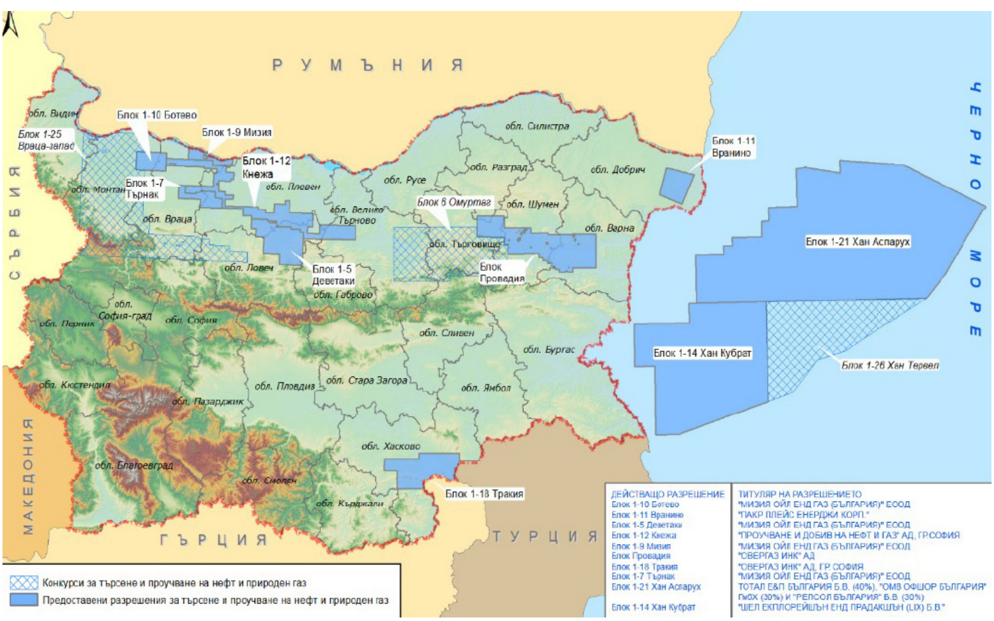
Table 9.45 **Natural Gas demand, Mtoe, 2014-2018**

	2014	**2015**	**2016**	**2017**	**2018**
GIC natural gas	2,4	2,6	2,7	2,8	2,6
FEC natural gas by sectors	1,2	1,3	1,3	1,4	1,3
Industry	0,8	0,9	0,9	0,9	0,9
Transport	0,2	0,2	0,2	0,2	0,2
Households	0,0	0,1	0,1	0,1	0,1
Services	0,1	0,1	0,1	0,1	0,1

Source:Eurostat

Bulgaria has been producing natural gas from its continental shelf in the Black Sea since 2001. The increase of local production in 2011 and 2012 follows the development of new fields in Kaliakra and Kavarna, however, in recent years production has been declining with only a small part (1-3%) of the inland consumption of natural gas covered from indigenous sources. The country relies mostly on natural gas imports to meet its domestic demand.

Map 9.23 **Current Oil & Gas exploration blocks in Bulgaria**



Source: Ministry of Energy

[33] Concession Register of Bulgarian Ministry of Energy

Table 9.46 **Natural Gas supply, Mtoe, 2014-2018**

	2014	2015	2016	2017	2018
Production	0,2	0,1	0,1	0,1	0,0
Import	2,2	2,5	2,6	2,7	2,6
Export	0,0	0,0	0,0	0,0	0,0
Stock Changes	0,0	0,0	0,0	0,0	0,0
Gross Inland Consumption	2,4	2,6	2,7	2,8	2,6

Source:Eurostat

Up to 2018 the sole importer of natural gas in Bulgaria was Russia. Bulgaria also acts as a transit route for Russian gas destined for Turkey, Greece and North Macedonia. Natural gas imports were almost stable during 2014-2018, albeit higher when compared to 2010-2013. The import of natural gas is based on long term Take-or-Pay" contracts between Bulgargaz (Bulgaria) and Gazprom (Russia) and cover exclusively inland consumption needs. The Take-or-Pay clause in Gazprom contracts was abolished as part of commitments related to the European Commission's antitrust CASE AT.39816 - Upstream gas supplies in Central and Eastern Europe.Being nearly 100% dependent on gas imports from Russia via a single route, Bulgaria continued to be vulnerable to gas supply disruptions over the period 2015-2019. The realization of new interconnection projects with neighbouring countries is likely to contribute both to the diversification of routes and, partially, suppliers over the next 5 years.

Table 9.47 **Energy dependence of Natural Gas**

	2014	2015	2016	2017	2018
Energy dependence of Natural Gas	94,1%	97,0%	96,5%	97,6%	98,7%

Source:Eurostat

Concerning upstream developments, currently there are 13 concession contracts[33] for gas exploration and production. The gas fields are located mainly on the north and north-east of Bulgaria. The main exploration and production companies are Melrose Resources, Oil and Gas Exploration and Production, and Direct Petroleum. The map below illustrates the current oil & gas exploration fields in Bulgaria. Bulgaria even though has a long-term transit agreement with Gazprom until 2030 and has been shipping Russian gas to Turkey, Greece and the Republic of Macedonia along the Trans-Balkan pipeline, is no longer transiting gas to Turkey, since from 2020 onwards it off-takes volumes from TurkStream 2 via the Strandja 2 – Malkoclar interconnection point for its own needs as well as for onward supplies to Greece and the Republic of North Macedonia. It is also expected to ship gas to Romania via the Negru Voda 1 – Kardam interconnection point where capacities will be made available for Third Party Access (TPA), and transit gas to Greece and the Republic of North Macedonia under the terms of its existing 2030 agreement with Gazprom.

Bulgartransgaz is the owner and operator of the national gas transmission network and of the Chiren single underground storage. Bulgartransgaz is also responsible for the administration of the natural gas market and balancing market under Natural Gas Trading Rules. The company is a 100% subsidiary of the state-owned Bulgarian Energy Holding (BEH) and is under process of certification as an independent transmission operator under the Energy Law, transposing the requirements of Gas Directive 2009/73/EC. Bulgargaz, which is a subsidiary of the BEH, is a single supplier and a public provider of natural gas for the whole country. Although there are rules and procedures stipulating the free access to the national grid, there have not been any companies taking advantage of this facility.

In January 2019, the Gas Hub Balkan EAD company was established by Bulgartransgaz EAD in line with the implementation of the concept for establishing a gas distribution centre on the territory of Bulgaria and the company has started stock exchange trading since December 2019. Gas Hub Balkan was developed with the assistance of the European Commission and envisages the construction of a natural gas distribution centre on the territory of Bulgaria, including the necessary gas transmission infrastructure, and a stock exchange for natural gas trade. The gas distribution centre will aim to connect the natural gas markets of Hungary, Croatia, of Slovenia and through them the Member States of Central and Western Europe and the countries of the Energy Community - Serbia, Northern Macedonia, Bosnia and Herzegovina. The company operates a trading platform for the needs of the domestic natural gas market. In synergy with the physical infrastructure of the gas distribution centre, the company aspires to operate the first liquid physical and commercial gas hub in the region. Gas distribution is performed by private regional and local companies, which perform licensed activities of gas distribution and supply for final consumers, connected to the gas distribution grids. However, the gas distribution network is not well developed. About 17% of natural gas consumption corresponds to customers of the distribution companies. Diversification of the sources and routes for the supply of natural gas is important for the country's energy security and independence.

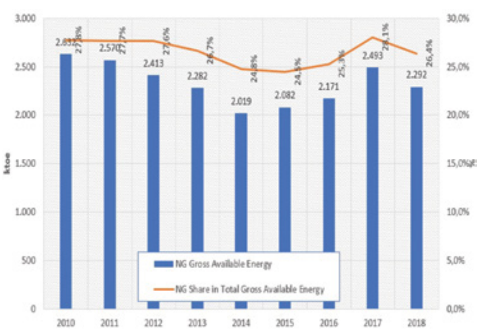
According to the Energy Strategy (ES) the country will strive to build reverse interconnections with Greece, Turkey, and Serbia and will look into possibilities for the extension of the existing gas storage at Chiren, as well as for building of a new storage facility at Galata. There is already an interconnection with the Romanian transmission system, established in 2016, while the compression station on the Romanian side is still to be put into operation. The National Energy and Climate Plan 2021-2030 has the same goals as the ES.

Concerning unbundling of the gas market in Bulgaria, Bulgargaz & Bulgartransgaz (BEH subsidiaries) are in charge of gas supply & national gas infrastructure and also the sole storage facility operator. On the 24th of August 2020 Gastrade SA (operator of Alexandroupolis LNG Terminal) announced the signing of the agreement for the acquisition of 20% of its share capital by the Bulgarian company Bulgartransgaz. It is expected that through the implementation of ongoing or forthcoming projects aiming at diversification of routes and sources of gas supply (participation in transnational gas corridors, interconnectors with the neighbouring countries and access to LNG terminals and storages) and continuing development of production from domestic reserves, energy security of domestic consumers will be guaranteed. A priority of the National Energy and Climate Plan 2021-2030 is the development and extension of households' gasification. On one hand, this will increase gas imports, increasing gas dependency, but on the other hand, higher use of natural gas will improve the energy efficiency ratios as less energy will be lost in transformation processes.

Croatia

Croatia's gas demand reached 3 bcma in 2020. It has the second highest contribution from domestic production in the region after Romania, although domestic production is declining gradually (especially the offshore production). About 45% of demand comes from the power generation and especially heat cogeneration sectors. In 2017 natural gas contribution in total primary energy supply reached 2.493 ktoe[34] or 28%. Also, domestic natural gas production reached 1.230 ktoe (1,43 bcma) or 29% of total domestic production. Primary energy production in Croatia in 2013-2018 decreased at an average annual rate of 1,9%. Noteworthy decreasing trends are recorded in the production of natural gas at 7,4% long term annual decrease. Indigenous natural gas production in 2017 met 51% of total domestic demand according to Eurostat Energy Balance Sheets 2017 Data. On the contrary, natural gas consumption has recovered in years 2017-2018 after a steady decrease between 2010 and 2014.

Figure 9.109 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**

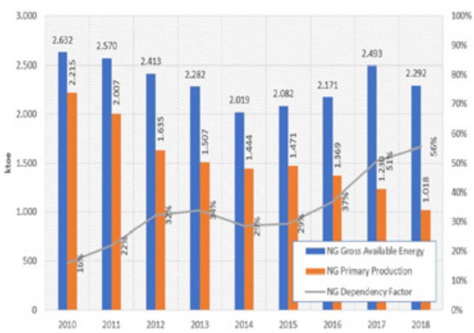


Source: Eurostat Energy Balance Sheets

[34] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

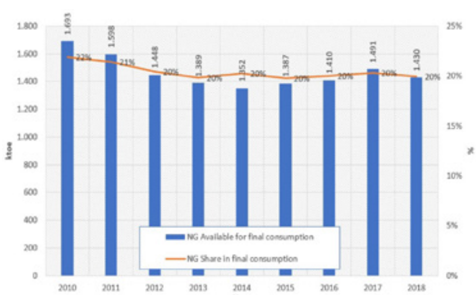
9

Figure 9.110 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

Figure 9.111 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

Croatia's total consumption of natural gas in 2018 amounted to 96,43 PJ (2,8 bcma). Total consumption of natural gas increased from 2013 by 0,2% yearly, with a decrease during 2018-2017 amounting to 7,9%. In terms of final energy consumption, the share of natural gas fuels is much lower and it amounts 13,0% in 2013 (1 bcma). Croatian gas demand rose by around 3% year on year to 2,46 bcma in 2019, according to HEP (Hrvatska elektroprivreda).

Around 59% of the total consumption accounted for rising industrial and power generation demand, while the remainder came from falling demand at local distribution zones. Rising gas-fired power generation may support gas consumption in the coming years as HEP will construct an additional 150MW gas-fired heat and power (CHP) unit at the EL-TO Zagreb plant by 2022.The country currently has around 762MW of installed gas-fired capacity in total.

In the upstream sector, Croatia produces 43,07PJ of natural gas (1,2 bcma) which correspond to about 45% of its natural gas needs. Proven reserves of natural gas amount to 10,3 bcm. Natural gas is produced from 18 on-shore and 3 off-shore exploration areas meeting 45 % of total domestic demand. Historically, Croatian offshore and onshore natural gas production had covered most of the country's annual demand but production output has been declining gradually in recent years. Data by Hrvatska elektroprivreda (HEP Group), showed that local production dropped by around 15% year on year to 760 million cubic metres (mcm) in 2019, accounting for around 30% of annual demand. The consequence is a rise in imports, which enter via the interconnectors from Slovenia and Hungary.

In addition to domestic production, privately owned Croatian energy trader PPD has a 1 bcma supply contract with Russia's Gazprom, which creates tough competition for potential LNG deliveries. In 2018 1,6 bcma of natural gas was imported from various countries. All imported natural gas was acquired in the open gas market. Croatia does not have any long-term import contracts. Transportation of natural gas is a regulated energy activity performed as a public service. The energy entity Plinacro d.o.o. is the transport system operator of the Republic of Croatia and is owned by the Republic of Croatia. Plinacro d.o.o. manages the network of the main gas and regional gas pipelines through which natural gas from domestic production (the northern part of continental Croatia and the Northern Adriatic) and from imports via Slovenia (Rogatec - Zabok) and Hungary (Donji Miholjac–Dravaszerdahely) is transmitted to exit metering/regulating stations where the gas is delivered to gas distribution systems and to end (industrial) customers directly connected to the transport system.

Gas distribution is a regulated energy activity performed as a public service. In 2018, gas distribution in the Republic of Croatia was performed by 35 energy entities. According to the Croatian Gas Association total distributed gas quantities in the Republic of Croatia in 2018 amounted to 1,2 bcma, of which 0,6 bcma were distributed to households and 0,6 bcma to users of the commercial sector. In 2018, the total number of distribution system end - users amounted to 671.740. In 2018 there were 626.307 household customers, and 45.433 commercial users. In 2018, 49 gas suppliers grouped into 14 balancing groups, used the gas transmission service. The head of the balance group HEP Trade d.o.o. has taken a 31,2% share of the gas volume from the transportation system, the head of the balance group HEP d.d. took a 27,4% of the gas volume, the leader of the INA balance group d.d. a 15,4% quantity of gas, and the leader of the balance group Prvo plinarsko društvo d.o.o. used 12,2% of gas, while the remaining 10 balance groups between them took over 13,8% of gas.

Cyprus

One of the main targets of the Cyprus National Energy and Climate Plan for the period 2021-2030, is the development and exploitation of Cyprus' indigenous natural gas sources and the introduction of natural gas in country's energy mix for decarbonising the islands of energy system (primarily power generation) and its adaptation to natural gas as an intermediate fuel that will allow the development of Renewable Energy Sources. Also, the development of necessary natural gas infrastructure (e.g. LNG imports) will increase flexibility of the national energy system and safeguard Security of Supply. Concerning the development of an internal natural gas market and network, the Natural Gas Public Company (DEFA), has been established and is responsible for the import, storage, distribution, transmission, supply and trading of natural gas, and the management of the distribution and supply system of natural gas in Cyprus. The council of Ministers of the Republic of Cyprus has issued a decree dated 18/06/2008, which appoints DEFA as the sole importer and distributor of natural gas in Cyprus, which effectively means that DEFA is not only the sole importer and distributor of natural gas on the island but also the solitary entity allowed to supply the fuel.

Although there are major natural gas discoveries in Cyprus since 2011 (Aphrodite gas field), up until now there is no natural gas production. The domestic natural gas market is regulated by the Cyprus Energy Regulatory Authority (CERA) and all the relevant EU Directives have been fully transposed and dictate the regulatory regime for the gas sector in Cyprus. The natural gas segments and potential gas consuming sectors consists of power generation, industrial users, domestic & commercial users, road transport & marine fuel/bunkering. According to recent studies the domestic natural gas demand is estimated to be 0,8 bcma in 2023 and reach 1,6 bcma by 2039.

Efforts are underway for bringing gas to the island to be utilized in the local market for electricity production and in the future to cover the demand of other consumers as well. More specifically:

- on the 4th of June 2019[35] DEFA launched a tender process for the supply of LNG for the Vasilikos FSRU, attracting expression of interest from 25 suppliers. Through this Request for Expressions of Interest (RfEoI), DEFA invited LNG suppliers to express an interest in supplying LNG to the LNG Import Terminal through a combination of medium and long-term supply via one or more LNG Sales and Purchase Agreements (SPAs) and supplemental cargos via multiple Master Sales Agreements (MSAs). DEFA intends to import 0,6 bcm of LNG through Gas Sale – Purchase Agreements (GSPAs) with duration between three to four years, maintaining the option to purchase LNG also from SPOT markets.
- On the 13th of December 2019[36], a contract for the design, construction, and operation of the LNG terminal in Vasiliko, was signed between the Natural Gas Infrastructure Company (ETYFA) and the international consortium China Petroleum Pipeline Engineering CO LTD, Hudong - Zhonghua Shipbuilding, Metron SA and Wilhelmsen Ship Management. The LNG import

[35] https//www.eprocurement.gov.cy/epps/cft/prepareViewCfTWS.do?resourceId=3710219
[36] https://www.defa.com.cy/en/announcements/80-
[37] https://www.energean.com/media/3549/20191119-proposal-to-cyprus-eng.pdf
[38] Greece – Cyprus in New Energy Era, IENE – June 2019 / https://www.iene.gr/page.asp?pid=5058&lng=1

terminal will be located at Vasiliko Bay, near Limassol, and consists of a floating storage and regasification unit (FSRU), a jetty for mooring the FSRU, a jetty borne gas pipeline and related infrastructure. The FSRU will be permanently berthed in Vasilikos bay and have a storage capacity of 125.000m³.

It will be capable of unloading LNG from LNG carriers ranging in size between 120.000m³ and 217.000m³. The project has an estimated cost of 290 million Euros and has already secured a funding of 40%, or up to 101 million Euros, as a grant from the EU under the Connecting Europe Facility (CEF) financial instruments, while the Electricity Authority of Cyprus (EAC) will contribute 43 million Euros securing a 30% stake in ETYFA. The construction of the project is expected to be completed by end the summer of 2022. Furthermore, ETYFA will cover the remaining part of the cost with funding from international lenders such as the European Investment Bank and the European Bank of Reconstruction and Development, with state guarantees. The infrastructure's operational expenditure (OPEX) is estimated at €10,5m a year.

- On the 19th of December 2019[37] Energean Oil & Gas submitted an application to import and supply natural gas to Cyprus commencing in 2021. The submission of the applications follows the 'Karish to Cyprus Preliminary Pipeline Development Plan', according to which, natural gas will be transported through pipelines from the Karish offshore block to the "Energean Power" Floating Production, Storage and Offloading unit (FPSO), and from there through a pipeline to Vasiliko. The pipeline from the Energean Power FPSO to Vasiliko will have a total length of 215 kilometres and the investment is estimated to 350 million US Dollars.
- On June 2020, the European Investment Bank (EIB) approved €150 mln to fund the landmark construction of the LNG terminal. The EIB loan has a duration of 20 years with a favourably low-interest rate and will cover capital construction expenditure.

Regarding indigenous hydrocarbon deposits offshore Cyprus, a thorough investigation of the latest developments was published by IENE in June 2019[38]. Concerning the Aphrodite gas field, contractor and the Republic of Cyprus have completed discussions on the Aphrodite Field Development and Production Plan (AFDPP), which was approved.

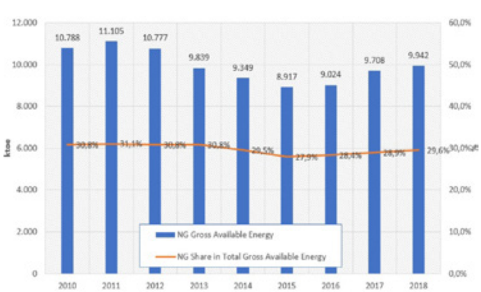
As a result, an Exploitation License for the production of the Aphrodite field issued in November 2019. According to the AFDPP, natural gas production is expected to begin in 2025. Gas from the Aphrodite gas field is going to be transmitted to Egypt via a subsea pipeline, mainly to the Idku LNG Terminal for liquefaction and re-export, as well as for the domestic market.

On the 20th of July 2020, Chevron announced[39] that has entered into an agreement with Noble Energy (the primary concession holder on the Aphrodite gas field) to acquire all of the outstanding shares of Noble Energy in an all-stock transaction valued at $5 billion.

Romania

Gas demand in Romania reached 9.708 ktoe in 2017 and 9.942 ktoe in 2018. Romania's gas consumption reached a low in 2015, has rebounded since, without however reaching the 2010-2012 levels (Figure 9.112).

Figure 9.112 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



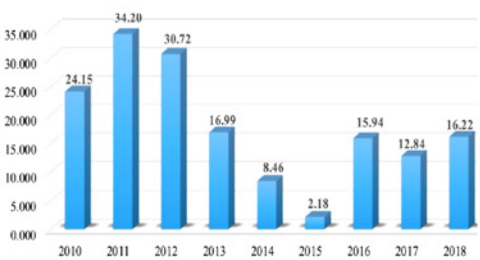
Source: Eurostat Energy Balance Sheets

[39] https://www.chevron.com/stories/chevron-announces-agreement-to-acquire-noble-energy

Romania is the second largest gas market in the region after Turkey. Also, Romania is the region's major gas producer (currently 2nd largest in the EU after Netherlands). Production currently stands at 10 bcma and is dominated by Romgaz and OMV Petrom, accounting for 95% of national output and split almost equally between OMV Petrom (48%) and Romgaz (46%). Romania is traditionally an onshore gas producer. The most impressive discovery to date – the Neptune gas field in the Black Sea, in 2012 - has not led to an investment decision yet. The first Romanian Black Sea gas may start flowing in 2021 from the Ana and Doina gas fields, part of the Midia project, developed by Black Sea Oil and Gas (BSOG) which will add 1 bcma to the market.

Romania's consumption profile is determined by high gas imports during winter and low gas imports during summer (when consumption relies mostly on domestic gas). The highest gas imports in the past decade were recorded in 2011 and 2012, and the lowest gas imports were recorded in 2015 (Figures 9.113 & 9.114).

Figure 9.113 **Natural Gas Imports 2010-2018**

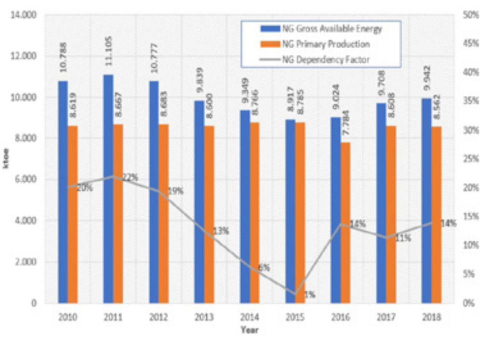


With imports from Russia and since 2010 from Hungary now at low levels, Romanian supply/ demand is very close to being balanced (Figure 9.114). If onshore production can be held at present levels, then the opening of the new offshore fields would turn Romania into a small exporter by the mid-2020s.

In case that Romania meets the demand growth potential of the region, gas from the Caspian (Southern Gas Corridor) or the East Mediterranean, would have to move further to find markets.

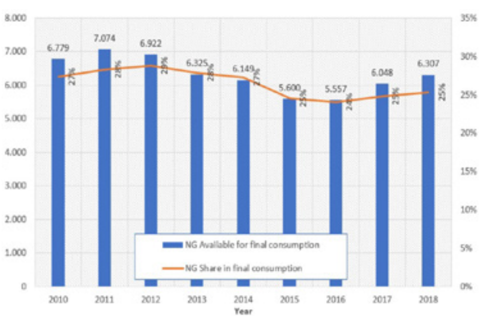
Romania in 2018 imported 1,6 bcma of natural gas, representing 14% of its domestic consumption (11,5 bcma) and therefore achieving the lowest Natural Gas Dependency Factor of the region.

Figure 9.114 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

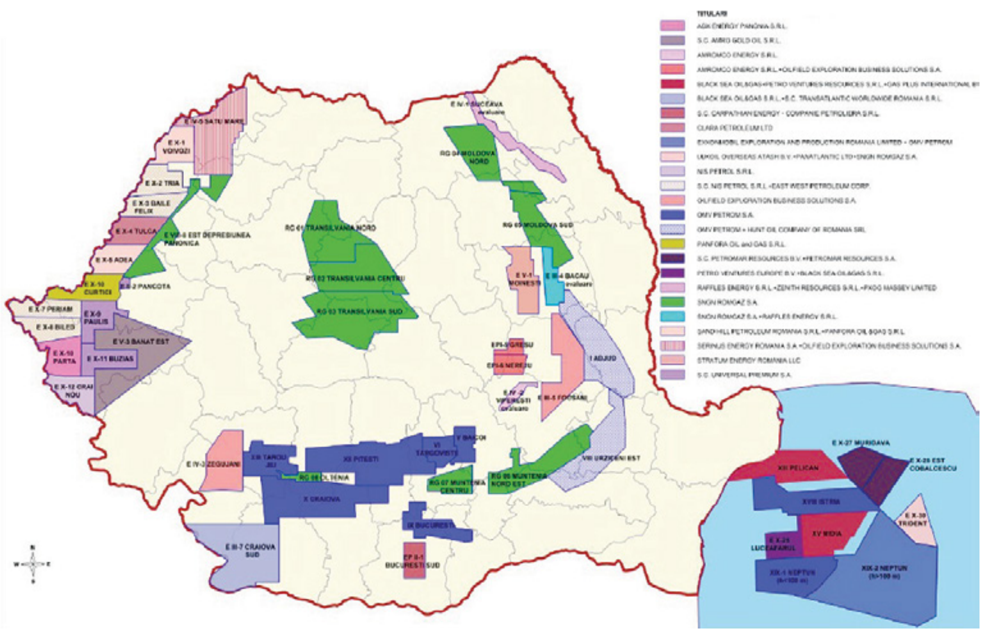
Figure 9.115 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets EnerBalance-Sheets

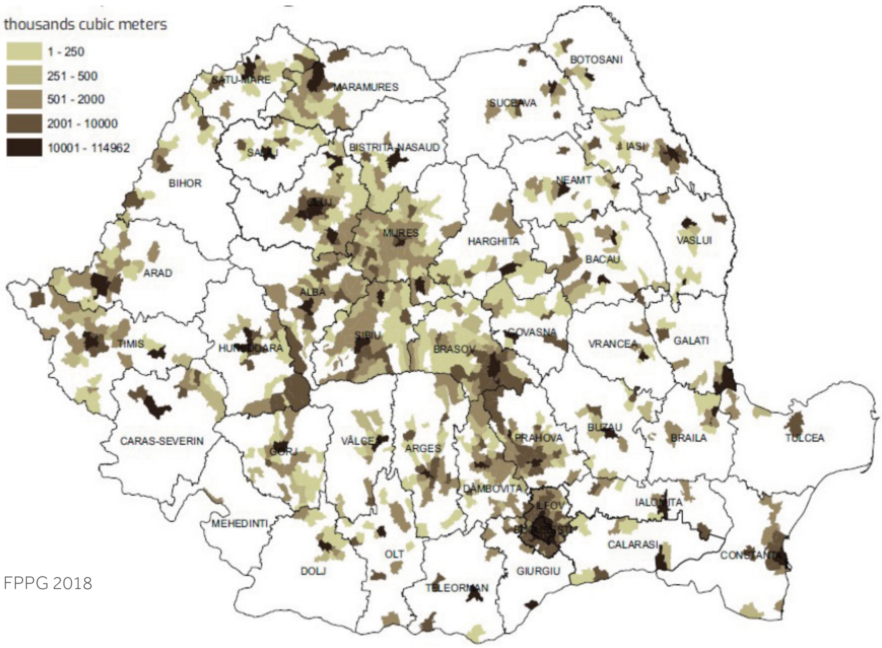
Romania remains a transit route even though with a diminished role. With the direction of transit from south to north, Romania would not be able to off-take gas for its needs from the Trans-Balkan line. It would have to secure volumes from Ukraine via the Mediesul Aurit-Tekovo interconnection point, some 700 km northwest from the Isaccea-Orlovka interconnection point.

Map 9.24 **Romania's Concession Areas**



Romania has achieved full liberalization of the gas market on July 1, 2020. Until June 30, 2020, there was a de facto price cap on domestic gas at 68 lei/MWh. More broadly, the current situation in the gas market is shaped by demand destruction (due to the economic Covid-induced slowdown).

The Romanian gas market is highly concentrated on the production side, it is essentially an oligopolistic market, with 2 big players: Romgaz and OMV Petrom (together they account for 90% of the domestic gas production) as mentioned above. The other players are Amromco Energy, Serinus Energy Romania, Stratum Energy Romania, Raffles Energy, Mazarine Energy Romania, Hunt Oil Romania, and Foraje Sonde.It is less concentrated market on the supply side, with 84 gas suppliers and 31 gas distributors. Gas transport, storage and distribution is regulated, the rest of activities are in the free market. Households account for up to 30% of gas consumption, while industry and commercial end-users account for 70%. Households in urban areas use natural gas, while in the countryside it is largely biomass (firewood) that is used for heating and cooking. There are 3,6 million residential consumers. Gas supply in the residential sector is dominated by Engie and E.ON, which together account for 90%.



Source: FPPG 2018

The non-residential consumers (industry, electricity production, district heating, chemical industry) are up to 200.000 customers. OMV Petrom is an important supplier to large industrial customers and commercial customers (businesses, small industrial customers), but is not present on the residential segment. Both Romgaz and Petrom's domestic production, but also import gas, supply the chemical industry which is one of the biggest consumers. Azomures (the biggest producer of fertilizers, owned since 2011 by Swiss company Ameropa) is now the main industrial consumer of gas, especially since Interagro's plants have closed down or have been under restructuring following bankruptcy procedures in the past years.

CHPs are major users of natural gas, with ELCEN (the main supplier of heat in Bucharest) being the biggest such customer. Romgaz is the main gas supplier for CHPs. Many coal-fired power plants have switched in recent years to natural gas in order to comply with stricter environmental standards. This trend will continue in the coming years, with natural gas displacing coal-fired power generation, especially in cogeneration.

Utilization of Natural Gas in transport is incipient. Despite having domestic gas production, Romania did not give too much thought until now to Natural Gas as an alternative fuel (as CNG or LNG) for sustainable transport. No LNG re-fueling infrastructure exists to date.

At EU level, here is a major shift away from natural gas under way. Financial institutions (such as the European Investment Bank) have excluded fossil fuel projects (including gas) from future financing. As climate finance develops further driven by the EU decarbonization agenda, this will reduce funding opportunities available for gas projects.

In Romania, it took more than 10 years for decision-makers to understand that natural gas is a transition fuel (hence its days are numbered). Therefore, the upcoming decade presents a last window of opportunity to invest in domestic gas related infrastructure. Despite being a gas producer since 1909, Romania's gas grid covers less than half of the country's household use (estimates range between 35% and 40% in terms of household that have access to the gas grid).

In October 2020, Romania's president approved Law no. 214, which enacts GEO no. 128/2020 which creates a National program for connecting the population to the gas grid. The law creates the possibility for the costs of connecting to the gas grid to be covered by EU funds during 2014-2020 (under LIOP, Axis 8) as well as in the upcoming 2021-2027 period. The funding will support the transformation of existing natural gas grids into smart gas distribution grids. In September 2020, the EU Parliament has passed an amendment which would allow EU countries to use the Just Transition Fund also for natural gas projects in coal dependent mono industrial regions. This keeps the door open for gas as a transition fuel in the next decade.

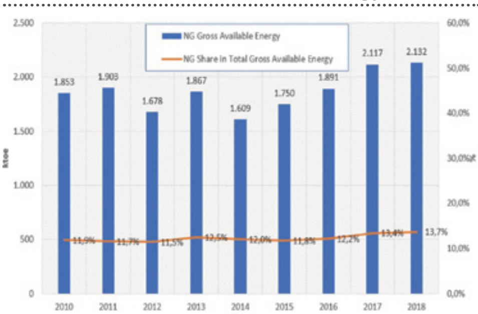
On the upstream side, 6 years were lost (between 2012-2018) with adopting a fiscal regulatory framework for Black Sea gas development. When finally adopted in 2018, the oil and gas companies held back on making an investment decision. Furthermore, with the changed global circumstances (gas glut and demand destruction), Exxon wants to exit the Romanian Black Sea, and so does Lukoil. Both are looking to sell their shares in the perimeters where gas discoveries were made. Exxon has been looking for 2 years for potential buyers of its 50% stake. Finally, after much foot-dragging and other proposals under consideration, Romgaz submitted a bid to buy Exxon's share of the perimeter for €900 million in early April 2021. If Romania manages to get its act together and kickstart production of the Black Sea gas, that would be the biggest development on the natural gas market.

Onshore, the situation does not look better. Excessive and haphazard regulation (such as the price freeze at 68 lei for sale of domestic gas to end-consumers in 2019-2020) resulted in over-taxation of domestically produced gas in comparison to imported gas (which was not subject to these additional taxes) and led to an increase of gas imports in 2019 and the shutdown of some domestic gas wells deemed unprofitable (mostly belonging to Romgaz). A dash for gas in power generation has been underway since 2015, with more and more CHPs gradually switching from coal to natural gas in Romania.

Serbia

Serbia's gas demand in 2017 increased by 12% in comparison to 2016 at 2,7 bcma. The market is extremely concentrated between State gas company Srbijagas and Gazprom throughout its supply and distribution chain. Domestic gas production covers around 20% of the market and the Petroleum Industry of Serbia (NIS) is the sole producer. The remaining supply is imported from Russia. Gazprom Export sends gas via Yugorosgaz, under long-term contract with Srbijagas. The long-term contract runs until 2021 and provides 1,8 bcma in 2018 and up to 2 bcma to 2021, although actual imports were higher in 2017. Natural gas is the third most used primary energy source in Serbia, after coal and oil. In 2017 natural gas contribution in the total primary energy supply reached 2.117 ktoe[42] or 13% and 2.132 ktoe (2,479 bcm) or 14% in 2018.

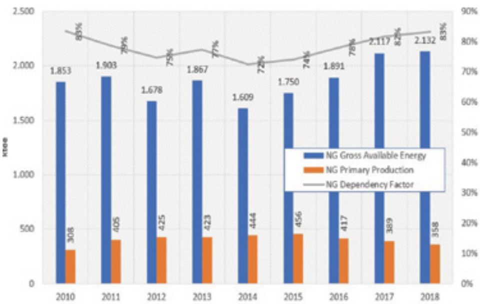
Figure 9.116 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



Source: Eurostat Energy Balance Sheets

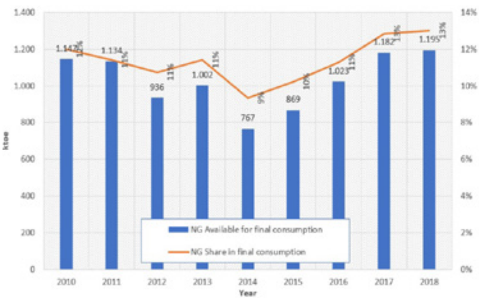
[40] The National program financed from EU funds allocated for 2014-2020 will run until December 31, 2023.
[41] The National program financed from EU funds allocated for 2021-2027 will run until December 31, 2029.
[42] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

Figure 9.117 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

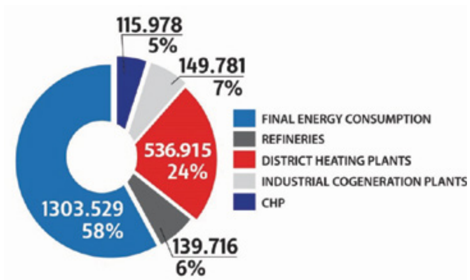
Figure 9.118 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

Also, natural gas domestic production reached 389 ktoe (0,452 bcma) in 2017 or 3,7% of total domestic production. Domestic production covered 18% of gas demand while the remaining amounts were secured by imports from Russia. Natural gas imports from Russia under long-term and other contracts amounted to 2,198 bcm in 2018, and all imported quantities were taken over from Hungary's transportation system. In 2018 import dependence had already reached 82% for natural gas. In terms of final energy consumption, the share of natural gas reached 1.182 ktoe in 2017 (13 %) and 1.195 ktoe in 2018 (13%).

Figure 9.119 **Natural gas transformation and consumption structure - 2018 (mcm, %)**



Serbia's proved and probable (2P) natural gas reserves amounts up to 3,37 Mtoe. Serbia's total geological reserves of natural gas are small and can be estimated at 50 Mtoe. Natural gas exploration and production in Serbia is performed exclusively by the Petroleum Industry of Serbia (NIS).

A race is underway among coal, natural gas and renewables to provide power and heat to Serbia's fast-growing economy. Coal share decreases, natural gas consumption increases, and renewables have a greater share in the energy mix than before. Considering the depleted natural gas and crude oil deposits in Serbia, the trend of increased import dependence continues. Transmission and transmission system operation are performed by natural gas transmission system operators: Srbijagas-Transportgas and Yugorosgaz-Transport.

Natural gas market participants include:

- producers (NIS JSC),
- suppliers (66 companies),
- public suppliers (33 companies),
- transmission system operators Srbijagas-Transportgas and Yugorosgaz-Transport,
- distribution system operators (33 active companies) and
- one storage operator UGS Banatski Dvor.

Serbia currently consumes about 2,5 bcma. Industrial production is beginning to grow and Serbia will certainly need more gas. In the past five years, Serbia's natural gas consumption increased by about 5% per year, while the domestic production has fallen significantly. In the upcoming period, it is expected that the domestic production will continue to decline.

Given the increase in industrial consumption, the planned construction of several CHP installations and expanding the country's natural gas transportation and distribution network it is estimated that annual consumption in 2030 will be about 4 bcma.

Under the Energy Law, the following regulated energy activities are of general interest:

- natural gas transmission and natural gas transmission system management,
- natural gas storage and natural gas storage facility management,
- natural gas distribution and natural gas distribution system management and
- public supply of natural gas.

Serbia's Energy Agency (AERS) is the competent body regulating the natural gas price for public supply, determining the natural gas transmission and distribution system access price and the natural gas storage access price.

In order to ensure Security of Supply for end users, it is stipulated that households and small customers whose facilities are connected to the natural gas distribution system are entitled to public supply at regulated prices, if they opt not to choose another supplier. Small natural gas consumers are the final customers whose annual consumption of natural gas is less than 100.000m³. The Serbian Government has appointed Srbijagas as the supplier of public natural gas suppliers under public tendering.

Bilateral market is functioning in the natural gas sector. In the wholesale natural gas market, buying and selling takes place directly between market participants. The wholesale natural gas market in 2018 was based on trade between natural gas suppliers and between natural gas suppliers and producers. In 2018, three suppliers (Srbijagas, King gas and Cestor Veks) and one producer, NIS, participated in the wholesale market. The average wholesale price at which suppliers sold natural gas to other suppliers in 2018 was 34,03 RSD/m³ (~0,29 €/m³).

At the end of 2018, the business of distribution and distribution system operation was performed by 32 licensed distribution system operators. In addition to distribution system operators, Srbijagas and Yugorosgaz, distribution and distribution system operation is performed by 30 other companies, most of which are owned by municipalities and cities, some are mixed and partly privately owned. The average weighted approved distribution system access price for all distribution networks in Serbia as of 31 December 2018 was 4,35 RSD/m³ (~0,037 €/m³).

In the retail market, supply was carried out at unregulated and regulated prices. Since 2018 all customers, except households and small customers, had to buy natural gas on the free market. As in the case of end users the Serbian Government appointed Srbijagas as a public supplier with natural gas under the same conditions and price.

During 2018, a total of 1.881 million m3 was delivered to buyers on the free market, while 321 million m3 was delivered to buyers under regulated prices. The average weighted retail price realized on the free market in 2018, including the transportation and distribution system use costs, was 35,26 RSD/m³ (~0,30 €/m³), while the realized weighted average retail price on the regulated market was 34,82 RSD/m³ (~0,29 €/m³).

The greatest share of natural gas, over 1.778 million m³ (81%) of the total amount was sold to final customers by Srbijagas in 2018. The second greatest share was sold by the DP Novi Sad Gas with 72 million m³, or about 3,3%, while Yugorosgaz came third with 51 million m³ or 2,4% of the total amount sold in 2018. Individual share of the remaining suppliers in the total amount is some 2%.

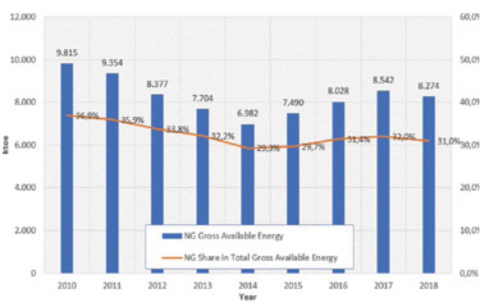
The 2025-2030 Energy Sector Development Strategy considers two natural gas consumption scenarios: reference scenario and energy efficiency measures implementation scenario. Both scenarios foresee an increase of gas consumption, both for transformation input (CHP gas facilities, increase of gas share in district heating plants and auto producers) and for final consumption.

Around 5 million, or 70% of Serbia's population, lives in areas with a developed gas transportation network, with further natural gas system expansion and consumption growth potential. In the upcoming period, natural gas consumption will be governed by various energy sector factors (natural gas price, infrastructure development, prices of other energy sources, etc.), general economic and social development factors (GDP growth, purchasing power of the population, implementation of environmental regulations, demographic indicators, structure of industrial production, etc.). Further increase of import dependence can be expected, from 82% in 2018 to around 90% by 2025.

Hungary

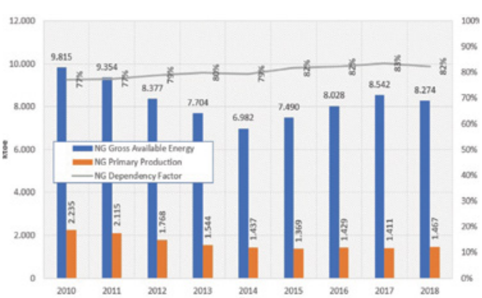
In 2017 natural gas contribution in total primary energy supply reached 8.542 ktoe[43] or 32% and in 2018 it reached 8.274 ktoe or 31%.

Figure 9.120 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



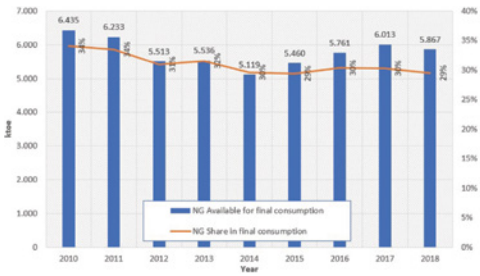
Source: Eurostat Energy Balance Sheets

Figure 9.121 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

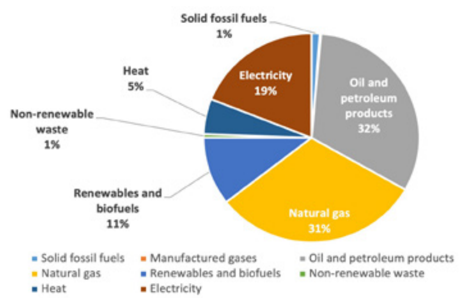
Figure 9.122 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

The contribution of natural gas in final energy consumption in 2017 reached 6.013 ktoe or 30%. Domestic natural gas production reached 1.441 ktoe in 2017. Natural gas represents circa 33% of the final energy consumption, with electricity representing circa 20%.

Figure 9.123 **Final Energy Consumption Breakdown 2018**

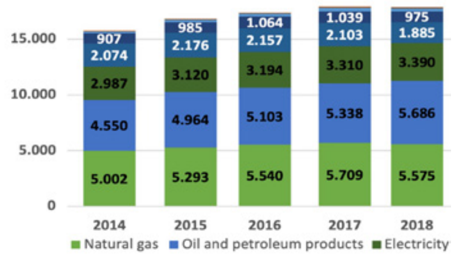


Source: HEA - National detailed Energy Balance -Eurostat format, 2018

In the years following up to 2018 the share of oil and petroleum products has slightly increased, whereas the share of renewables and biofuels has decreased. The share of natural gas and electricity stayed practically the same.

[43] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

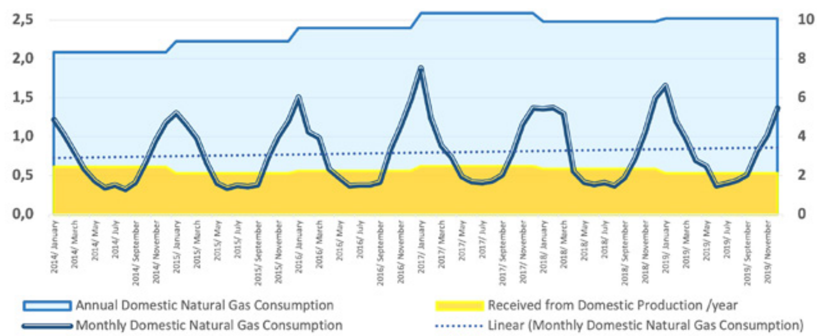
Figure 9.124 **Final Energy Consumption Breakdown 2014 - 2018**



Source: HEA - National detailed Energy Balance - Eurostat format, 2018

The domestic gas consumption[44] in 2019 was 10,08 bcma. The average domestic gas consumption in the 2017-2019 period amounted to 10,12 bcma, with a slight upward trend. The average y-o-y increase in annual domestic gas consumption was 3,94% in the 2014-2019 period. However, it must be noted that gas consumption is strongly influenced by the number of Heating Degree Days (HDD) occurring each year. The domestic production[45] in 2019 amounted to 2,13bcma vs 2,46 in 2014. The trend of production is slightly decreasing, -2,4% in the period of 2014-2019. The difference between domestic consumption and production must be covered by imports. The share of imports in the domestic consumption reached 78,8% in 2019 vs 70,5% in 2014. The share of natural gas imports in primary energy imports reached 44,29% in 2018 vs. 32,4% in 2015. The natural gas consumption related to GDP however has decreased significantly to ca. 60% of the 2000 value.

Figure 9.125 **Domestic Natural Gas Consumption (bcm/month & year, 15C)**



Source: HEA - Data of Natural Gas Companies – 2020

Figure 9.126 **Domestic Natural Gas**

Source: HEA-FGSZ – Data of the Hungarian Natural Gas System 2018

[44] Does not include the production directly delivered to consumers, associated gas from thermal water production, domestic CH4 production and the auto consumption of producers.

[45] Certified quantity delivered to the natural gas grid from the producers. Does not include production delivered to island networks, directly to consumers or auto consumption of the producers.

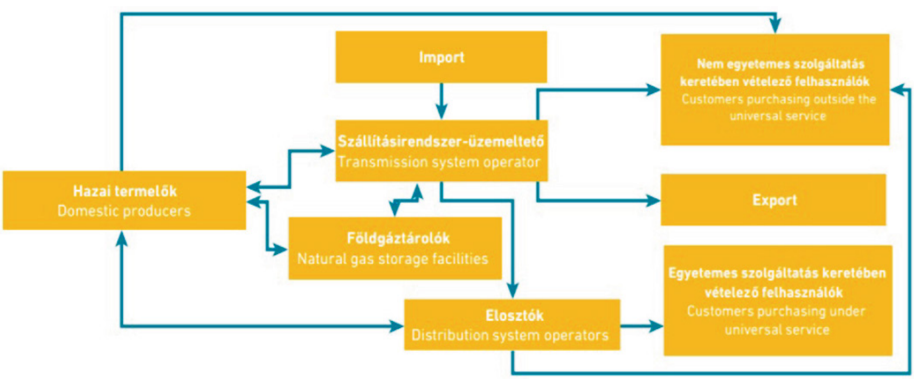
The imported and domestically produced natural gas is sold to domestic users by traders and universal service providers. Natural gas distribution systems are operated by the 10 regional distributor companies. Most of the regional distribution activity is carried out by five large companies that are geographically divided between them.

Since the market opening in 2004 the retail market has been characterized by a dual structure. In the free market segment, prices are formed by the market. Consumers eligible for universal service can get natural gas on a regulated (maximized) price. The customers of eligible for universal service are the household consumers, other customers with purchased capacity below 20 m³/hour, and the local governments up to their capacity in supplying consumers living in rented apartments controlled by governments. Non-eligible customers either purchased natural gas from the competitive market as before or entered the free market upon termination of their eligibility to universal services (customers with medium and low consumption and district heating generators). In 2018, 3,7 bcm of natural gas was sold within the universal service for eligible customers (3,35 bcm household customers and 0,36 bcm other) and 4,8 bcm was sold to non-eligible customers on the wholesale market (99,9% non-household customers).

The universal supplier is the NKM Energia Zrt, a subsidiary of the NKM Nemzeti Közművek Zrt, a subsidiary of the state owned, MVM Group. The HHI[46] competition index of the sales to household end users was 9984 in 2018. In 2018, there were 43 companies active in the wholesale market, while the HHI competition index of sales in the wholesale market was 1987 in 2018.

The model currently in place in the domestic natural gas sector is presented in Figure 9.127.

Figure 9.127 **Domestic Natural Gas Sector**



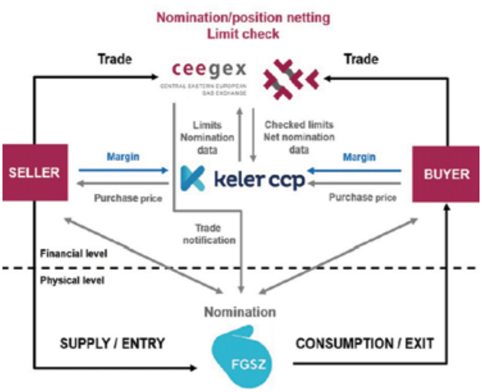
Source: HEA-FGSZ – Data of the Hungarian Natural Gas System 2018

The Central Eastern European Gas Exchange CEEGEX Ltd[47] is the organized gas market providing physical within-day and Day-Ahead market trading on Hungarian Virtual Point (MGP) and on locational points. Total spot volumes reached 34.338 GWh in 2019, a four-fold increase compared to the 8.405 GWh volumes of 2018. There are 37 exchange members and two market makers. In 2019, the premium over the CEGH price was between -0,2 – 2,5 EUR/MWh and over TTF was between 0,2 – 4,0 EUR/MWh.

[46] The Herfindahl-Hirschman Index (HHI) is a common measure of market concentration and is used to determine market competitiveness, often pre- and post-M&A transactions.
[47] Part of the HUPX Group, a subsidiary of the electricity TSO MAVIR, a subsidiary of the state owned MVM Group

The Central Eastern European Gas Exchange CEEGEX Ltd[47] is the organized gas market providing physical within-day and Day-Ahead market trading on Hungarian Virtual Point (MGP) and on locational points. Total spot volumes reached 34.338 GWh in 2019, a four-fold increase compared to the 8.405 GWh volumes of 2018. There are 37 exchange members and two market makers. In 2019, the premium over the CEGH price was between -0,2 – 2,5 EUR/MWh and over TTF was between 0,2 – 4,0 EUR/MWh.

Figure 9.128 **Hungarian Virtual Point**



Source: HUPX Group Brochure 2020-Energy Business Motion

Gas Future Contracts[48] are available on Hungarian Derivative Energy Exchange – HUDEX Energy Exchange Ltd., member of the HUPX Group with two market makers: RWE and MFGK.

The balancing market is organized by FGSZ, the gas TSO within its FGSZ Trading Platform Ltd., where there are currently 21 members. The main policy and strategic goal in Hungary has been and still is the provision of competitively priced and secure natural gas to domestic consumers. Also, the new energy strategy foresees energy efficiency increase, thus potentially reducing household consumption in the following decade. In order to achieve these goals, Hungary over the last decade has connected its transmission network with all neighboring countries except for Slovenia, thus facilitating access to different gas supply sources available in the region which can ensure security of supply under a diverse set of adverse conditions.

In line with the Capacity Allocation Mechanisms Network Code (CAM NC), FGSZ carried out the non-binding phase of the incremental capacity process and has found that the incremental capacity process shall start on HU>AT; HU>SK and HU>SI directions.

Energy major Shell has signed a supply deal with Hungary to supply the nation with LNG via the upcoming Krk import terminal in Croatia. Hungary has agreed to buy 250 mcm of natural gas equivalent per annum for a period of six years, which secures 10% of its gas supply from the West, a critical step in Hungary's attempts at energy diversification. Until now Hungary has imported only Russian pipeline gas under long-term supply agreements with Gazprom and its export arm.

Hungary's government has also agreed on a 6,2 bcma deal with Gazprom and has said it wants a flexible long-term agreement (LTA) with the company. In June 2020, Hungary's state-owned firm MVM announced plans to purchase up to 1 bcma of gas through the Krk terminal from 2021 to 2028.

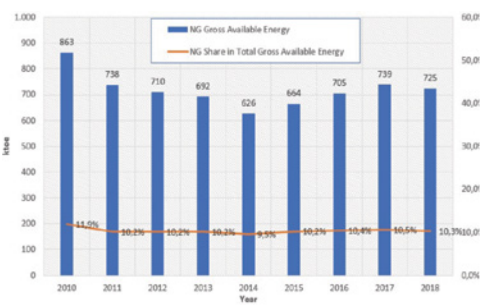
In June 2020, TSO FGSZ approved an investment plan to construct a pipeline to Serbia with a capacity of 6 bcma. Hungary expects to start importing Russian natural gas via Serbia in October 2021. Also, Hungary is ready to invest in additional capacities to ensure imports of larger-than-planned volumes of gas if local companies indicate that there could be an annual demand of more than 6 bcma. The governments of Serbia and Hungary will soon sign an agreement on the construction of a cross-border natural gas interconnection.

[48] Balance of Month, Seasonal, Yearly contracts

Slovenia

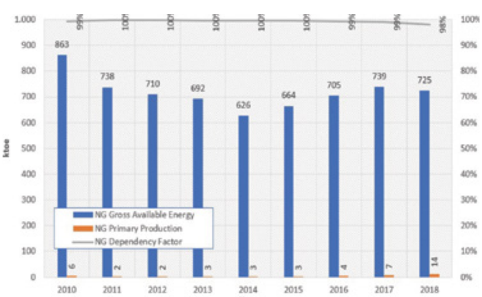
Slovenia's gas demand in 2017 was 0,9 bcma, supplied roughly equally from Gazprom and from the Austrian hub. In 2013 there have been also small imports credited to Algeria. Most demand comes from industry. Power sector demand is tiny, in part because of the 700 MW nuclear plant at Krsko, a Joint Venture with Croatia which started commercial operations in 1983. In 2017 natural gas contribution in total primary energy supply reached 739 ktoe or 11% and in 2018 it reached 725 ktoe[49] or 10%. The contribution of natural gas in final energy consumption in 2017 reached 615 ktoe or 12%. Domestic natural gas production is minimal reaching 7 ktoe in 2017, although it increased in 2017 and 2018, amounting 0,016 bcm in 2018 and representing 1.8 % of Slovenia's demand, being several times higher than in 2015 (See Figure 9.129).

Figure 9.129 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



Source: Eurostat Energy Balance Sheets

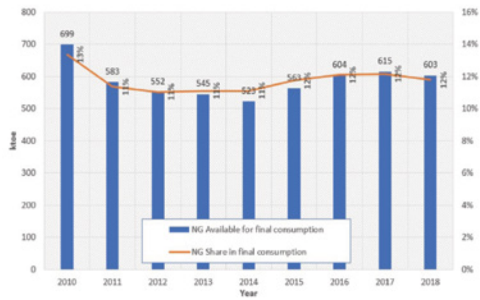
Figure 9.130 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

[49] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

Figure 9.131 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



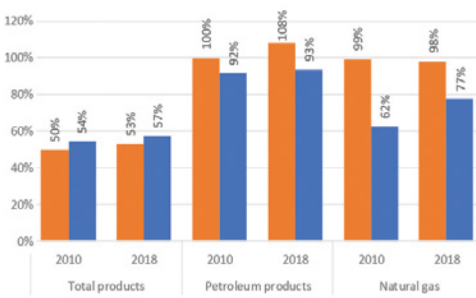
Source: Eurostat Energy Balance Sheets

Market development and liquidity growth in Slovenia depends on residential gas consumption and the industry as the country has no storage capacity and has only 492 MW installed gas-fired generation capacity. At the same time, Slovenia will benefit from developments in its southern neighbour as the country has been a supply transit country to Croatia, competing with Hungary. However, Slovenia's share was challenged by Hungary in 2017, after the expiry of long-term supply contracts between a number of suppliers in Slovenia and the latter, significantly lowering export tariffs, leading to a drop in Slovene transit flows to Croatia. Exports rose sharply again in 2019 as Slovenia exported around 588 mcm in 2019, up by 66% compared to 2018, according to data by Slovene system operator Plinovodi. This also had a positive impact on liquidity on the Slovene virtual point operated by Plinovodi, where 767GWh changed hands on the Over-The-Counter (OTC) market in 2019, up by 55% year on year, according to Plinovodi. At the same time, 263GWh was traded on the Slovene balancing market, which was a 23% year-on-year increase.

Slovenia will likely benefit from future LNG deliveries to Croatia as Plinovodi, the Hungarian counterpart of FGSZ and Italy's Snam Rete. Gas recently reshaped the long-awaited Slovene-Hungarian interconnector project and broadened its concept into a Hungary-Slovenia-Italy (HUSIIT) supply corridor. Plinovodi and FGSZ will offer capacity on the proposed interconnector at the annual yearly capacity auctions 6 July. The project would provide access for Slovene shippers to the vast Hungarian storage capacity and also allow Hungarian shippers to reach the Italian PSV market. The pipeline would not only open storage arbitrage opportunities but also improve Slovenia's security of supply. In the upstream sector, exploration of natural gas in Slovenia is ongoing in one location in the North-Eastern part of Slovenia, in the "Petišovci globoko" reservoir. Exploration of natural gas has in 1943, and from 1963-2017 342 mcm of natural gas have been extracted. The largest production was reached in 1989, when more than 33 mcm was produced. Company Geoenergo d.o.o., which is a subsidiary of Slovenian oil company Petrol, is the holder of an exploitation concession contract for this field since 2002, giving it the exclusive right for oil and gas redevelopment project in this area until 2022. The project of natural gas production is in joint venture with Geoenergo d.o.o. being undertaken by Ascent Slovenia Limited, the Project Manager. In 2017 a contract with Croatian oil and gas company INA was signed for delivery of raw natural gas to the Molve processing facility since they were not able to get permit for the construction of a natural gas processing facility in Slovenia. Geoenergo and Ascent are facing strong opposition to this project from environmental organizations. The latest decision of the Slovenian Environmental Agency, that separate permits for hydraulic fracturing are needed, has once again delayed the production. Unfortunately, Ascent Resources plans to take multi-pronged legal action against Slovenia because of this. Exploration of natural gas is regulated by the Mining Act[50].

Today, Slovenia is completely import dependent for natural gas where the import dependency is also very close to 100 % (Figure 9.132).

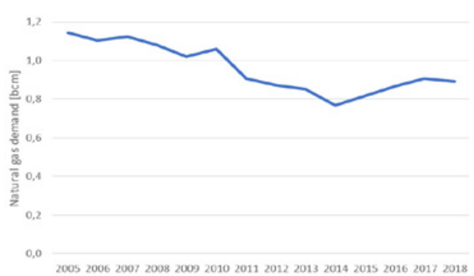
Figure 9.132 **Slovenia's Import Dependency**



Source: Eurostat

National gas demand has been decreasing from 2005 and it reached a minimum in 2014 of 0,728 bcma. In the period 2015-2017 demand increased, reaching 0,859 bcma in 2017. In 2018 a slight decrease has been observed resulting in consumption of 0,843 bcma. First data for 2019 is indicating a small increase of consumption (0,5 %).

Figure 9.133 **Natural gas demand in Slovenia (2005-2018)**



Source: SORS

Table 9.48 **Key natural gas data in Slovenia**

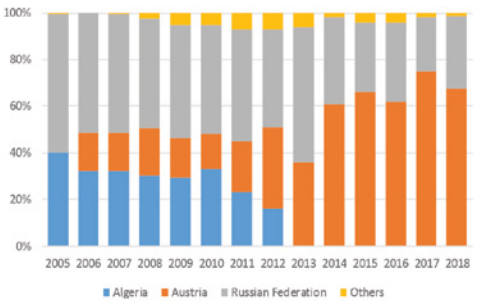
	2000	2005	2010	2015	2017	2018	2019*
Production	7	4	7	3	8	16	
Demand	1.014	1.141	1.059	816	907	890	895
Transformation	164	165	193	121	150	148	
Industry	604	665	593	494	539	572	
Residential	72	121	140	127	146	136	
Other sectors	174	191	134	74	72	34	
Net imports	1.007	1.137	1.053	813	899	874	
Import dependency	99%	100%	99%	100%	99%	98%	
Natural gas in TPES	**13%**	**13%**	**12%**	**10%**	**11%**	**11%**	

Source: SORS *2019 data are estimates

[50] Official Gazette of the Republic of Slovenia No. 14/2014.

In 2018, Slovenia gas was imported from Austria, Russia and Italy. 70% was purchased from Austria, while the majority of the rest from Russia and 0,5 % from Italy. In the period from 2014 to 2018 majority of natural gas came from Austria, while in the past also Italy (natural gas of Algerian origin) was an important source country. However, it is important to mention that natural gas from Austria is mainly originating from Russia.

Figure 9.134 **Natural gas imports in Slovenia by Country**



Source: SORS

Thus, the Slovenian wholesale natural gas market is shaped by imports through neighbouring transmission systems (Austria, Italy and Croatia), as mentioned above. Slovenian natural gas market is open and fully liberalized. Market transparency is ensured by prohibition of market manipulation and trading on the basis of inside information, a requirement for effective and timely disclosure of inside information, and appropriate legislative framework for market monitoring. In this context the Slovenian Energy Agency, as the market regulator, plays a key role.

The majority of natural gas has been imported through the interconnection with Austria, where at the Baumgartner gas hub and Austrian storages Slovenian energy traders buy most of the natural gas for the domestic market. In 2018 70% of all gas imports in Slovenia came through interconnection with Austria. As a result of market liberalization there is a trend in a decrease in the number of long-term contracts established directly with natural gas producers in Russia. According to the Slovenian Energy Agency, in 2018 some 61,2% of natural gas was purchased on the basis of short-term contracts and the remaining 38,8% was purchased on the basis of long-term contracts. The major players at the Slovenian wholesale natural gas market are listed in Table 9.49 below. Also, Table 9.49 contains the so called Herfindahl-Hirschman index (HHI) of the Slovenian wholesale market. According to the Energy Agency, natural gas market concentration measured by HHI shows a very high degree of concentration on the Slovenian wholesale market. The HHI value strongly exceeds the limit (usually is 2000), which is a boundary between middle and high concentration level.

Table 9.49 **Market shares and the HHI of the natural gas wholesale market in 2018**

Name of the company	Market share
Geoplin	80,33%
Petrol	15,57%
Plinarna Maribor	2,71%
GEN-I	1,31%
Adriaplin	0,09%
Total	100%
HHI of the wholesale market	6.704

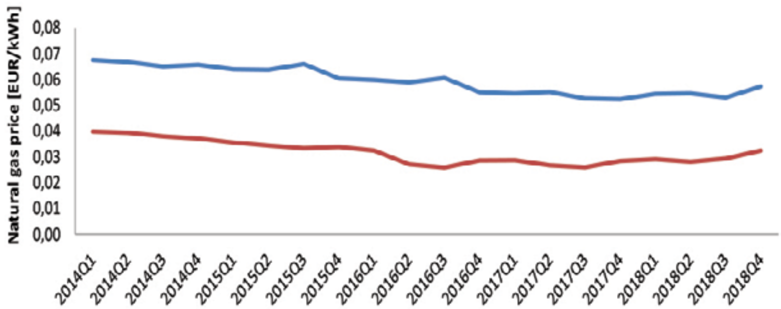
Source:Slovenia Energy Agency

Traditionally, the largest market share on the Slovenian wholesale market belongs to the company Geoplin, d.o.o, Ljubljana, which in 2018 had a market share of 80,33%. The second largest market player is the company Petrol which in 2018 had a market share of 15,57%. Petrol is also the largest trader and distributor of petroleum products in Slovenia.

In 2018, 23 natural gas suppliers (five less than in 2017) were active in the Slovenian retail market, which according to contracts supplied natural gas to 134.642 consumers (1.312 more than in 2017). A reduction in the number of active natural gas suppliers is the result of mergers and acquisitions but also it has to be emphasized that two suppliers left the retail market last year (2020). Final consumers can change their supplier at any time. Also, suppliers must publish on their websites offers for household and small business consumers. In 2017 prices reached the lowest level since 2011. In 2018 these trends changed a bit for certain groups of consumers.

However average prices remained almost unchanged. Compared with neighbouring countries, natural gas prices for typical household consumer in Slovenia in 2018 (final prices including all taxes and levies) were lower than in Austria and Italy but higher than in Croatia and Hungary. Also, in 2018 natural gas prices for typical household consumers in Slovenia remained below the EU-28 average. On the other hand, final natural gas prices including all taxes and levies for typical industrial consumers in Slovenia in 2018 were higher than in all neighbouring countries and remained above the EU-28 average.The development of natural gas prices in Slovenia since 2014 is shown in Figure 9.135 below.

Figure 9.135 **Development of natural gas prices in Slovenia**



Source: SORS and Ministry of Infrastructure

According to the new Slovenian NECP, natural gas is considered as an important transition fuel towards a climate neutral society. Slovenia has already established a favourable legislative framework for electricity production in natural gas fired highly efficient cogeneration units. Additionally, Slovenia has a favourable geographical position in relation to the flow of natural gas in Europe due to its close proximity to transmission routes from Eastern Europe (from Russia through Slovakia and Austria towards Italy and Croatia) and its border with Italy, where the transmission routes from the Mediterranean Basin and northern Europe converge. NECP includes concrete measures for the promotion of research cooperation and support mechanisms for joint development projects between companies from different energy sectors, namely electricity, natural gas and district heating. Slovenia is planning different projects to increase the operational security and expansion of the transmission system. In this context NECP, supports the implementation of pilot projects for the production of synthetic methane and hydrogen (indicative target of 10% share of methane or hydrogen of renewable origin in the natural gas transmission and distribution network by 2030). The future development of the transmission system will be in line with the expected physical flows of natural gas and system capacities, including new sources of synthetic gas. In the coming years Slovenia will prepare a regulatory and support environment for renewable gas alternatives and based on results of pilot projects, it will determine the maximum hydrogen content in the existing network.

Montenegro

Since the previous IENE SEE Energy Outlook 2016/2017, there has not been any major development concerning natural gas penetration in Montenegro's energy sector. The Government of Montenegro implements preparatory steps for potential gasification which could be achieved through involvement in the infrastructure developments concerning the Ionian-Adriatic Pipeline (IAP) and the Trans Adriatic Pipeline (TAP).

Estimations of final consumption of natural gas were based on the assumption that the IAP regional pipeline would pass along the coast of Montenegro and that gasification would include only coastal towns. Other than raising the energy standard of gasified households, this would represent a strong incentive for the further development of industry, especially tourism, in the coastal area.

Provided that natural gas is introduced over the next five years it is estimated that by 2030, gas final consumption will reach 46 million of m3. Households participate with large share in consumption, followed by the industry. Services, mainly tourism, would have consumption from 9 to 12 million of m^3 of natural gas. The Energy Development Strategy of Montenegro by 2030 stipulates the following recommendations about the development of the gas sector:

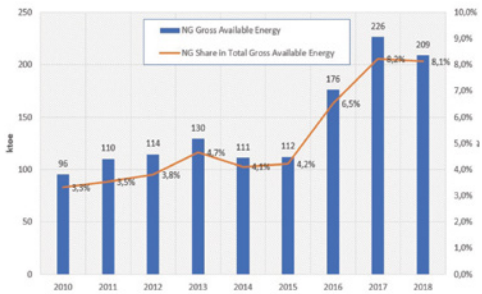
- Continue with intensive research of potential oil and gas reserves in the Adriatic Sea,
- Continue with the feasibility study for Ionian Adriatic Pipeline and determine optimal route through the territory of Montenegro taking in consideration long-term economic growth of the country,
- Continue with intensive cooperation with other participants in key projects (IAP and TAP) in the region.

Natural gas is a sector which is planned to play an important role in the energy market of Montenegro in the coming years. The development prospects of natural gas are promising for future investment. Given the fact, that the tourism is the dominant sector of Montenegrin economic development, the introduction of a system providing natural gas will definitely have a positive impact on the extension of the tourist season. Concerning potential domestic natural gas production, seismic exploration of oil and gas in the underwater began on November 2018. Surveys are planned for approximately 1.200 square kilometres of sea bottom, for which the concession was awarded to the Italian-Russian consortium Eni-Novatek. Some analyses show that Montenegro has 51 bcm of gas reserves. The data referred to the 330 km^2 in Ulcinj.

North Macedonia

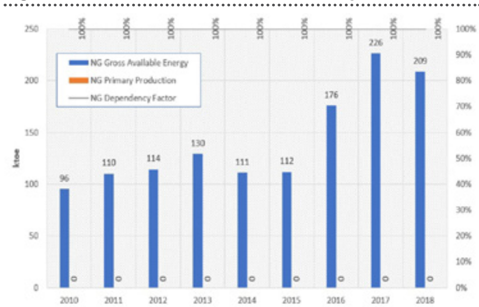
Currently, North Macedonia's gas demand is around 0,2 bcma. All of it is supplied from Russia via Bulgaria and up until the end of 2019 through the Trans Balkan system.In 2017 natural gas consumption reached 226 ktoe[51] which amounts to an 8,2% contribution of total gross available energy and reached 209 ktoe in 2018. Natural gas contribution in the final energy consumption reached 44 ktoe or just 2,2% and 43 ktoe in 2018. The unfavourably small contribution of natural gas in the final energy consumption against the high consumption of electricity is attributed to the limited energy needs of the metal melting industry and the small participation of CHPP plants in the energy economy of the country.

Figure 9.136 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



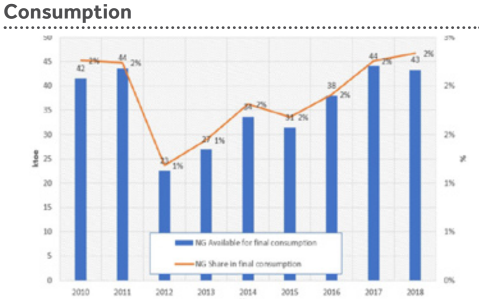
Source: Eurostat Energy Balance Sheets

Figure 9.137 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

Figure 9.138 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



Source: Eurostat Energy Balance Sheets

[51] Eurostat Energy Balance Sheets 2017 Data, 2019 edition

The country has a supply contract with Gazprom for 0,7bcma but has been off taking less than 0,3 bcma in recent years, which means there is sufficient available capacity on the border point with Bulgaria, but until now has been underutilised because of lack of alternative gas supplies in Bulgaria.

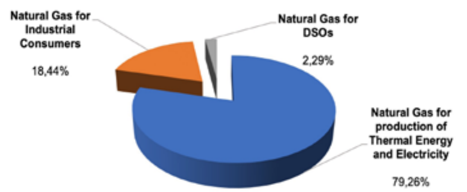
As a Contracting Member of the Energy Community, the country has committed to implement the EU's network codes including those on tariffs and congestion management (CAM) by February 2020. However, since it is not an EU member, there is no obligation for the Republic of North Macedonia to implement the rules as yet.

According to the data of the State Statistical Office and ERC, the total supply/imports of natural gas in North Macedonia rapidly increased during the last few years. In 2016 it reached 0,215 bcma, 0,276 bcma in 2017 and 0,255 bcma in 2018.

The largest consumption of natural gas occurs during winter months, which is to be expected considering that natural gas is mostly used for the production of thermal energy. During July and August there is a consumption deflection which is due to the operation of CHPP TE-TO, followed by significant increase in the winter period when TE-TO and few smaller CHPP operate in full capacity. The industrial consumers which are using natural gas for their processes and operate all year round define the minimum consumption.

Natural gas consumption in North Macedonia is dominated by Combined Heat and Power production plants and thermal power plants. Their portion in the final natural gas consumption for 2018 was 79,26%. Next are the industrial consumers with 18,44% market share, where dominant role belongs to the metal industry. At the end are the distribution companies with a share of 2,29%.

Figure 9.139 **Consumption of natural gas by consumer type in 2018**

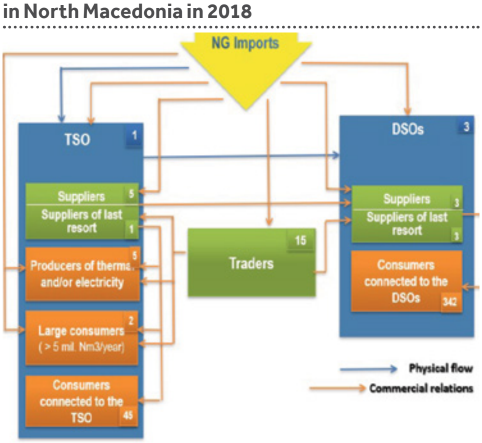


Source: ERC

North Macedonia is 100% dependent on natural gas imports, as there is neither domestic gas production nor ongoing gas exploration in the country. Almost the entire supply of gas is imported from Russia through the only entry point at the Bulgarian border. The natural gas market is governed by the Energy Law of 2018, which essentially transposes the Third Energy Packet. The corresponding secondary legislation is also in place and greatly implemented, with the exception of ownership unbundling and certification of the Natural Gas TSO, GA-MA. The certification is frozen by a long-lasting dispute on the majority ownership over the gas transmission system between the Government and Makpetrol, which currently both own 50% of shares in GA-MA.

The natural gas market in North Macedonia is fully liberalized as of the 1st of January 2015. Since then, no natural gas disruptions have been observed. The structure of the market is presented in Figure 9.140.

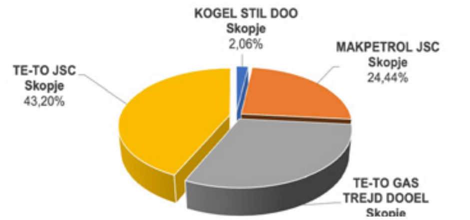
Figure 9.140 **Overview of the natural gas market in North Macedonia in 2018**



Source: ERC, Annual Report 2018

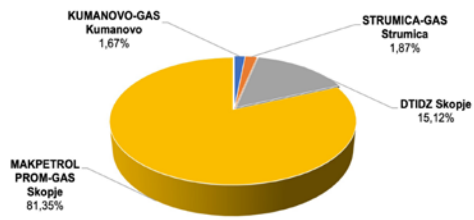
The market share of the traders and suppliers in the wholesale natural market is displayed in Figure 9.141, while the shares in the retail market can be observed in Figure 9.142.

Figure 9.141 **Market share of traders/suppliers at the wholesale natural gas market in 2018**



Source: ERC, Annual Report 2018

Figure 9.142 **Market share of the suppliers at the retail natural gas market for 2018**



Source: ERC, Annual Report 2018

Makpetol Prom-Gas supplies natural gas to consumers connected to the gas transmission system, while DTIDZ Skopje, Kumanovo Gas and Strunica Gas supply natural gas to consumers of the gas distribution network, respectively. DTRIZ Skopje and Kumanovo Gas purchase natural gas from Makpetol Prom-Gas[52].

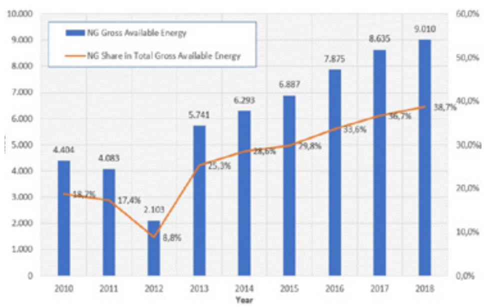
Natural gas is expected to play an important role in replacing coal and as a bridge fuel to 2050. There is an ambitious gasification plan, which includes interconnections with Greece and other countries. As projected by the Energy Development Strategy, the overall consumption of natural gas will constantly increase in the long term, with average annual rate of 7-10% depending on the success of implementing Energy Efficiency and RES measures[53].

[52] ERC, Annual Report 2018
[53] Strategy for Energy Development in North Macedonia for the period until 2040
[54] www.iea.org

Israel

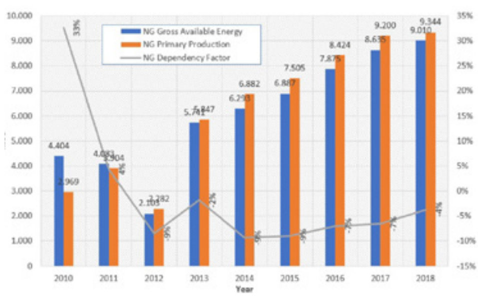
In 2017 natural gas contribution in the total primary energy supply reached 8.635 ktoe (10,04 bcma) or 37% and 9.010 ktoe (10,47 bcma) or 39% in 2018. In 2019 natural gas consumption reached 11,5 bcma, the government's goal is to reach more than 80% natural gas and 17% renewable energy in the power sector by 2030 and minimum coal usage.

Figure 9.143 **Natural Gas Gross Available Energy & Share in Total Gross Available Energy**



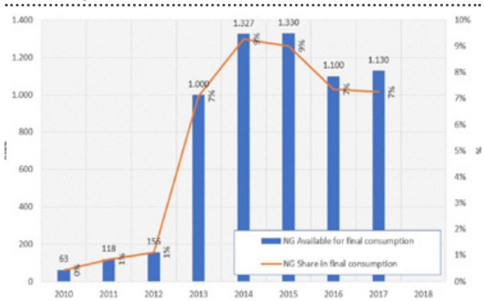
Source: Eurostat Energy Balance Sheets

Figure 9.144 **Natural Gas Gross Primary Production**



Source: Eurostat Energy Balance Sheets

Figure 9.145 **Natural Gas Available for Final Consumption and Natural Gas Share in Final Consumption**



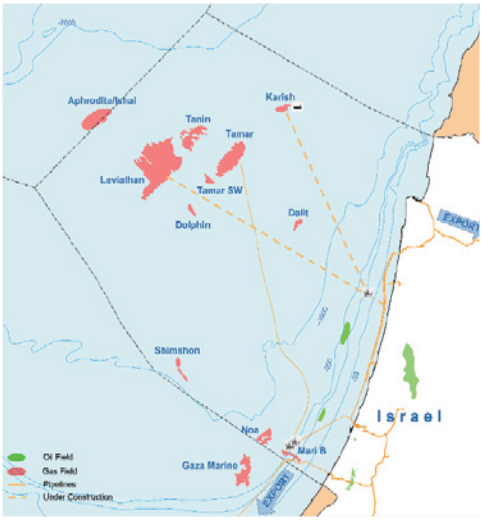
Source: : Eurostat Energy Balance Sheet

Gas consumption in 2018 (including exports) totalled 11,11 bcma – a 7% increase from 2017. During 2018 95% of gas demand was supplied by Tamar and the remaining 5% was imported in the form of LNG. Gas consumption by the industry rose by 12% compared with 2017 to 2,02 bcma, following the connection of new consumers to the distribution network. Since April 2013, with the commissioning of the Tamar field and construction of the LNG buoy, gas consumption in Israel has grown by 63%. By the end of 2018, 5 large conventional IPPs and 5 factories (CHP plants) were connected to the gas transmission system in addition to Israel's Electric Corporation (IEC) stations. New gas connections include 15 large industrial consumers, 69 consumers connected to the distribution network and 7 consumers were supplied CNG by trucks.

Distribution network end users consumed a total of 0,24 bcma in 2018 (21% increase from 0,2 bcma in 2017). In 2019 distribution network end users consumed more than 0,3 bcma. 90% of these customers are located in the South.

In the upstream sector, according to the Ministry of Energy, currently the total amount of recoverable gas reserves found offshore Israel is estimated at about 900 bcma. The first field to be connected to the shore was Mari-B, through the Mari-B production platform and the Ashdod Onshore Terminal (AOT), in 2004. The Tamar field started to supply gas to the domestic market in 2013. The development was accomplished in a record time of less than 3 years and included a 150 km long tie-back pipe connecting its deep-water subsea facilities to the nearshore production platform. The development of the huge Leviathan field started in 2016. This field will allow Israel, for the first time in its history, to export a substantial amount of gas to the neighbouring countries, while the Karish and Tanin fields will be developed through an FPSO, the first one in the region.

Map 9.26 **Israel's Gas Fields**



Source: Ministry of Energy

The LNG buoy in 2018 supplied 0,67 bcma in comparison to 0,52bcma in 2017. The Ministry of Energy collected 860 million NIS in royalties on gas during 2018. Leviathan's development has been completed and is in full commercial operation as stated since January 1st of 2020. Karish and Tanin received approval for part of the onshore pipeline that will later connect to the FPSO and have signed an agreement with INGL for the last 10 km offshore segment. The project is due to be completed in the first semester of 2021.

On the 9th of April 2020, Energean Oil and Gas announced[55] the completion of an independent Competent Persons Report on the Karish North Field, offshore Israel, and submission of an addendum to the Field Development Plan to the State of Israel's Ministry of Energy for Karish North. By the end of June 2020. Energean Oil and Gas had completed the main pipeline to link Karish and Tanin gas fields to Israeli shore. The 90 km pipeline will link to Energean's dedicated 8 bcma FPSO, which will gather gas from the fields before sending it via the new pipeline to Israeli buyers. Energean is developing a cluster of gas fields offshore Israel, comprising the Karish, Tanin and Karish North fields. The installation of the three sets of risers that will connect the three producing wells to the FPSO and then to

[55] https://www.energean.com/media/3774/20200409-karish-north-cpr-and-submission-of-fdp.pdf

the pipeline is expected to start in the fourth quarter and was expected to be completed in Q1 2021. First gas from Energean's fields offshore Israel could slip into the second half of 2021, according to a new timetable released June 8 for work on the FPSO. Energean has firm sales agreements for 5,6 bcma of gas with Israeli buyers and hopes to secure more offtake deals to be able to fully utilize the FPSO's 8 bcma capacity.

The transition to natural gas in the Israeli economy between 2013-2018 has led to a 62% reduction in SO_X and 50% reduction in NO_X emissions. Between 2013 and 2018, the emission of these pollutants declined by 62% and 50% respectively. The decline in emission of sulphur oxide and nitrogen dioxide has saved the Israeli economy $4 billion during this period (Gas Forum). Competition in the natural gas market began in January 2020, as the 610 bcm Leviathan gas field starts commercial production (1st gas flowed on 31.12.2019) and will increase to three independent gas suppliers by mid-2021 as the Greek-British company's Energean's Karish field comes online. In this respect, Israel will have 3 independent and separate gas pipelines coming onshore into Israel with a capacity to supply circa 30 bcma, by mid-2021, plus an FSRU to import LNG in case of emergency or for spot supply needs. The main sector, however, is indeed the country's natural gas market and between 2013 (when the Tamar field came online) and until the end of 2018, natural gas has saved over $17 billion in energy import costs.

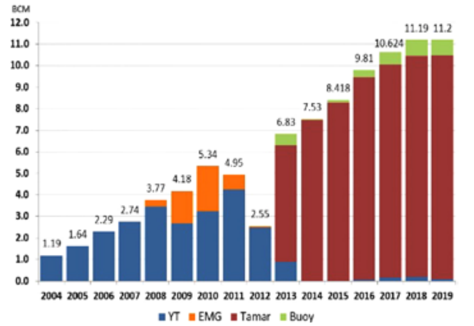
In terms of natural gas consumption, demand for gas has hitherto been restricted by the lack of availability of supplies to grow in line with demand, so that consumption will reach 11,2 bcma in 2019 (full year), comprised mainly of gas from the local Tamar field and circa 0,7 bcm of LNG imports. As of 2020, however, with the start of commercial production from the Leviathan field, consumption will be able to grow organically based on demand as shown in Figure 9.146. In addition to the electricity sector, natural gas is the primary energy source for Israeli industry connected to gas transmission infrastructure. For now, the use of natural gas in small and medium-sized industrial plants is still in its early stages, whilst residential, commercial and gas in transportation has not yet really taken off, partially due to the still limited scope of development of the low-pressure, privately owned, distribution networks, albeit CNG is starting to be used in transportation in Israel.

The first inroads of natural gas and electricity in the transportation sector, was facilitated thanks to supportive governmental regulations and policies, directed towards ceasing to use oil and to transition to natural gas and electricity for transportation. The government's goal is that in the industrial sector, 95% of the energy and steam required will be generated from natural gas as of 2030.

At the same time, the impetus for coal-to-gas switching continued in Israel, with a government panel approving a proposal to build two gas fired power plants that will allow the country to get closer to eliminating its dependence on coal by 2025. Even so, the quest for export markets continued, with Delek, one of the partners in Leviathan, saying that floating liquefaction was back on the table as an option to enable the expansion of the Leviathan project.

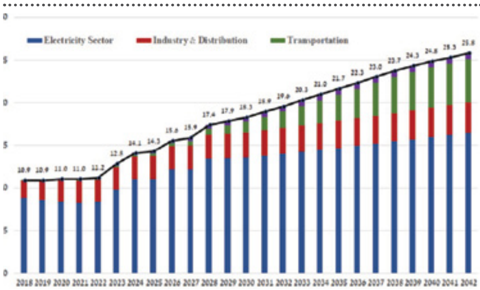
Although Israel has a lot of energy in the form of natural gas, Israel has hitherto only achieved just over 40% energy independence. The objective in the next few years is that more than 50% of the energy will be locally produced (increased use of natural gas and renewables and reduced coal imports and use in power generation and liquid fuels in transportation). The total saving for the market from the transition to gas between 2004 and the end of 2018 is estimated at 63,7 billion NIS, 49 billion NIS of which is in the electricity sector. Gas consumption has saved the Israeli industry 14,7 billion NIS. Between 2004 and the end of 2018, 83 bcm of gas were supplied in place of coal and distillates.

Figure 9.146 **Gas Supply 2004-2019**



According to the Ministry of Energy, accelerated growth in the use of natural gas is expected to continue in the coming years, increasing to 14-15 bcma in 2025, and to 18-19 bcm by 2030. The total forecast demand for the years 2018 to 2042 is 450 bcma (Figure 9.147).

Figure 9.147 **Gas Demand Outlook by Sector 2021-2042**



Source: Ministry of Energy

Kosovo

A natural gas market does not yet exist in Kosovo, as Kosovo has not any domestic production of natural gas and it is not linked to any operational natural gas supply network. A connection to natural gas supply would be an important option for the introduction of natural gas in Kosovo, which would impact the diversification of its fuel supply and also help increase Security of Supply. Gas supply and consumption in Kosovo is therefore limited to bottled LPG (liquefied petroleum gas).

The official policy of the Kosovo Government is to promote and support the inclusion of Kosovo in the regional natural gas projects. The Trans Adriatic Pipeline (TAP) project can offer a good opportunity to Kosovo to connect to the international natural gas network. In this regard, depending on the regional developments of gas projects in SE Europe, the Government of Kosovo remains committed to take advantage of all opportunities to be involved in joint natural gas projects in the Energy Community.

In order to create a perspective for development of the natural gas sector and fulfilment of the obligations that Kosovo has as a full member in Energy Community Treaty, the Kosovo Assembly in June 2016, adopted the Law no. 05/L-082 on Natural Gas, as part of its package of energy laws. Following this Law, the transposition of the European 3rd Package legislation was carried out, which was relevant for natural gas, mainly:

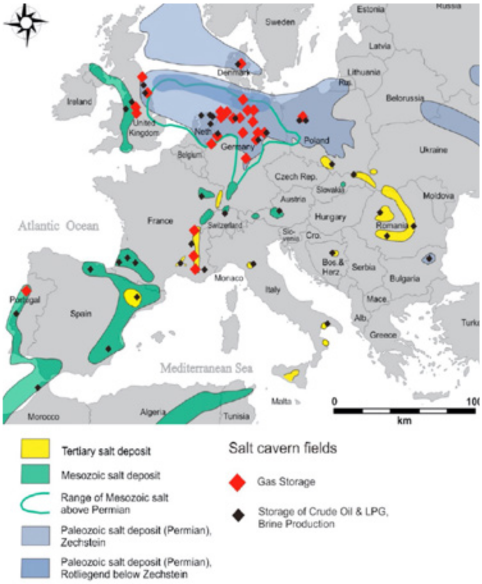
- Directive No. 2009/73/EC concerning common rules for the internal market in natural gas.
- Regulation No. 715/2009/EC on conditions for access to the natural gas transmission networks.

The law on natural gas lays the foundations of legal and regulatory framework for the transmission, distribution, storage and supply with natural gas and the operation of gas transmission and distribution systems. Consequently, this law determines the organization and functioning of the natural gas sector and access to networks and the gas market, once natural gas starts to be imported and used in the country

9.2.4 Natural Gas Storage in SE Europe

Storage sites constitute crucial energy infrastructure as they guarantee seasonal Security of Supply (SoS) by holding strategic gas reserves. Map 9.27 depicts Underground salt deposits and cavern fields in Europe.

Map 9.27 **Underground salt deposits and cavern fields**



Source: A review at the role of storage in energy systems with a focus on Power to Gas and long-term storage www.sciencedirect.com/science/article/pii/S1364032117311310)

In the SE European region, only 6 countries (Romania, Croatia, Serbia, Bulgaria, Hungary and Turkey) out of 15 examined have in place gas storage facilities. The total storage capacity amounts to 14,27 bcm with 44% of the region's capacity located in Hungary, 24% in Turkey and 22% in Romania. The majority of the rest countries of the region, taking into account the importance of storage facilities, plan to build new facilities or upgrade existing ones in the following years.

Table 9.50 **Underground Storage Capacity in SE Europe**

Country	Storage Capacity in bcm
Bulgaria	0,55
Croatia	0,44
Serbia	0,45
Hungary	6,33
Romania	3,10
Turkey	3,40
Total	**14,27**

Source: IENE

[56] Turkish Natural Gas Market Report 2018, EPDK 2019.

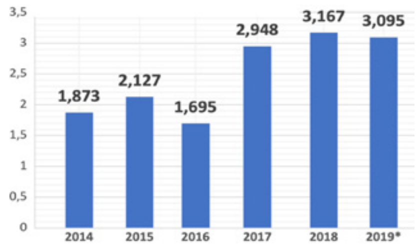
Apart from the operating storage facilities, new gas storage projects are under planning or in implementation phase in the region. More details about the technical characteristics and capacities of operating facilities, facilities under planning or potential facilities per country are described below. **Albania** has several suitable sites for gas storage, including, a salt dome in Dumrea (up to 2 bcm) and the depleted Divjaka gas field (up to 1 bcm). In **Turkey**, considerable efforts are under way to increase the natural gas storage capacities to 11 bcm by the year 2023. The first underground storage facility of Turkey BOTAŞ in Silivri is using the depleted natural gas fields of TPAO in northern Marmara Sea and Değirmenköy. The facility started its commercial operation in 2007 and reached with Phase II investments a working gas storage capacity of 2,8 bcm (Table 9.51). After the commissioning of the third phase of investment the capacity will increase to 4,6 bcm.

Table 9.51 **Underground storage capacity in Turkey**

Location	**Capacity (bcm)**	**Injection rate (mcm/d)**	**Withdrawal rate (mcm/d)**
Operational			
Botaş Silivri Phase II	2.8	16	25
Botaş Tuz Gölü Phase I	0.6	30	20
Under Implementation			
Botaş Silivri Phase III	4.6	40	75
Botaş Tuz Gölü Phase II	5.4	60	80
Planning			
Toren Tarsus Phase I	0.5		24
Çalık Tuz Gölü	1.0	10	20

Tuz Gölü underground storage facility is located near Sultanhani in Central Turkey. The facility is using salt caverns in 1.100-1.400 m depth created by solution mining. The first phase of the project was completed in February 2017. With the ongoing second phase investment the storage capacity will increase to 5,4 bcm. The other two envisaged projects are also planned to be implemented in salt domes in the Tarsus area near the Mediterranean Sea and in Tuz Gölü area, but no progress has been reported. In 2018 Turkey's underground storage capacity reached 3,291 bcm. The LNG storage capacity also increased from 0,943 bcm in 2018 to 0,968 bcm in 2019. The year-end natural gas stock in 2018 was 3,167 bcm and 3,095 bcm in 2019 (Figure 9.148).

Figure 9.148 **End of the year natural gas stock in Turkey**



* Preliminary figure, subject to change
Source: Energy Market Regulatory Authority

In 2018, the volume of the stored natural gas in the pipeline system was swinging between 0,250 and 0,380 bcm[16]. Finally, large investments in underground storage will be realized by BOTAŞ. Silivri Underground Storage Phase III project, tendered in December 2019, will be completed in 2022. Total investment of the project is estimated around 3,5 bill TL. Tuz Gölü Underground Storage Phase II investment project was also tendered in 2019 and has an investment budget of 19.3 bill TL. The project is expected to be commissioned in 2024.

In **Greece**, the Hellenic Republic Asset Development Fund launched an international tender for the concession for the use, development, and operation of an underground natural gas storage facility (UGS) in the depleted "South Kavala" natural gas reservoir. The UGS South Kavala, which is able to store up to 1bcm of natural gas, is intended to serve as an energy infrastructure that will enhance the security of supply in the Greek market as well as in Southeastern Europe by ensuring gas supply to end users and facilitating the Security-of-Supply obligations of power producers and natural gas suppliers. DESFA has already planned the connection of NNGTS to UGS South Kavala in the latest TYNDP.

In **Bulgaria**, the underground gas storage at Chiren is located near the city of Vratsa. It consists of 22 exploitation wells, a compressor station with an installed capacity of 10 MW and other equipment required to secure the injection, withdrawal, and quality of stored gas. The withdrawal rate in periods of high demand can be up to 4,2 mcm/d, while the respective rate for injection is 3,5 mcm/d.

In **Croatia**, there is an underground gas storage facility located in Okoli (UGS Okoli). The underground gas storage Okoli is controlled by Podzemno skladište plina, Ltd. which is owned by Plinarco. The designed capacity of the underground gas storage is 5.050 GWh. Maximum injection capacity is 200 MWh/h and the maximum withdrawal capacity is 300 MWh/h. PSP d.o.o. underground gas storage operator intends develop peak storage facility at Grubisno Polje.

The Peak storage facility at Grubisno Polje project will consist of two phases:

- Phase I foresees the extraction of gas from the gas reservoir/gas field Grubisno polje. Facilities and installations will be built for the gas treatment (natural gas plant), supervision system and process management, connecting pipelines to the wells, connecting pipelines to the main pipeline Virovotica-Kutina, access roads, water system etc.
- Phase II will be the development of the underground gas storage in the partially depleted gas reservoir of Grubisno polje. Working volume of the new UGS will be minimal at 25 million m^3, with a maximum level of injection capacity up to 1,4 million m^3/per day and maximum level of withdrawal capacity from 1,7 to 2,4 million m^3/per day, with a possibility of multiple injection and withdrawal cycles during winter season. The primary task of this underground gas storage would be to ensure peak withdrawal capacities during winter season, or more precisely as a support during withdrawal of gas from the seasonal gas storage in UGS Okoli.

In **Romania**, Underground Gas Storage facilities are located mainly at the centre of the country. Romania has the 4th largest storage capacity after Hungary, Turkey and Serbia at 4,5 bcm (47 TWh), with a regular use of 3 bcm/cycle (31 TWh). The maximum daily gas withdrawal rate exceeds 24 mcm/d, while the corresponding injection rate is 30 mcm/d. There are two storage operators: Romgaz (Depogaz) and Depomures. There are 6 UGS set up in depleted reservoirs, five of which are operated by Romgaz (total capacity of 2.76 bcm), and only one by Depomures (0.3 bcm).

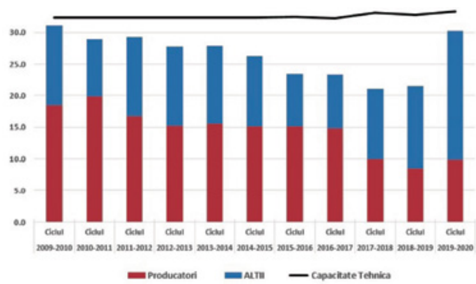
Table 9.52 **Capacity of Underground Gas Storages**

Storage name	Operator	Active capacity (TWh/cycle)	Extraction capacity (GWh/day)	Injection capacity (GWh/day)
Balaceanca	Depogaz	0.5452	13.176	10.98
Bilciuresti	Depogaz	14.3263	152.782	109.13
Ghercesti	Depogaz	1.6343	21.4	21.4
Sarmasel	Depogaz	9.5987	79.035	68.497
Urziceni	Depogaz	4.0168	50.157	33.438
Targu Mures	Depomures	3.1545	29	27
Total		**33.2758**	**345.55**	**270.445**

Source: Transgaz, PDSNT 2020-2029

Storage is not very flexible, as it developed mainly to deal with seasonal variations. Rate of injection/extraction is not designed for fast commercial use. Tariffs for gas storage are regulated.

Figure 9.149 **Reserved Gas Storage Capacity 2009-2019**



Note: color code: red= producers, blue= others, black= technical capacity, Source: Transgaz

As Figure 9.149 depicts, in the previous 4 cycles before the last one, storage usage dropped below 25 TWh, and climbed back tp 30 TWh in the 2019-2020 cycle, reflecting a wider stock build up and glut on the market. In addition, national legislation now obliges gas suppliers to hold minimum required quantities for each market segment.

In **Serbia**, Banatski Dvor Underground Gas Storage (UGS) is located in a depleted gas deposit whose capacity used to be 3,3 billion cubic meters of natural gas. There is currently 450 mcm of available capacity while the maximum productivity in the withdrawal process amounts to 5 million m³/day. After phase two of construction, the storage will have the capacity of 800 million cubic meters. This storage is connected by two gas pipelines. During 2018, more natural gas was taken from than delivered to storage facilities. At the beginning of 2018, there was 404 million m³ of commercial gas available in storage. From the transportation system, 273 million m³ were delivered to the storage, of which 3 million m³ was consumed by the storage's own consumption, while the remaining 270 million m³ of gas was injected for commercial purposes. Users have taken over 299 million m³ from the storage, also delivered to the transport system. At the end of 2018, there was 375 million m³ of commercial gas inside the storage facility. There are plans to build a new underground storage at Banatski Itebej, with capacity similar to the existing Banatski Dvor as well as a smaller one at Tilva.

In **Hungary,** there are 5 gas storage facilities, with a combined working gas volume of 6,33 bcm. The gas withdrawal capacity amounts to 78 mcm/d and injection capacity reaches 45,3 mcm/d.

Map 9.28 **GIE Storage Map 2018**

In **Slovenia** there is no Underground Gas Storage and there are no plans to construct a storage facility in the future. Good connection to European gas network system enables Slovenia to have high security of natural gas supply. The nearest underground gas storage is in Austria with capacity of more than 4,7 bcm, while Slovenia consumes 0,8 bcm per year.

9.2.5 Major gas infrastructure projects in SE Europe

Considering that the SE European region as a whole one can see that currently it is poorly interconnected as already pointed out. Hence, the development of natural gas infrastructure is of the utmost importance. Over the last 10-12 years, we have seen the emergence of a number of projects involving the construction of major, and smaller, gas pipelines across SE Europe. Most of these projects have evolved around the Southern Gas Corridor (SGC), through which gas from the Caspian region would be channeled to energy demanding European markets, via several countries in SE Europe. The realization of the SGC (Map 9.29) which was completed at the end of 2020 is undeniably a major milestone not only for wider SE European region but also for Central and Western European gas markets.

Map 9.29 **The South Gas corridor and the TAP pipeline**

Source: TAP AG, Snam, DESFA, ICGB, Gastrade, IENE, S&P Global Platts

Some of these projects, grand in formulation and ambitious in terms of deliverable gas volumes, have collapsed (e.g. the Nabucco pipeline), while others have been mothballed (e.g. the ITGI route). Other grandiose schemes such as the South Stream, although strictly speaking outside the remit of the South Corridor, but of relative importance, have been cancelled and pushed aside mostly due to political considerations, part of the never ending East-West (read USA/ EU-Russia) wrangle. In view of a preponderance of new regional projects, recently completed or under development, it is time to redefine the South Corridor, as already proposed by IENE, by including all different routes and gas supply sources. Therefore, an Expanded South Corridor, as shown in the following map (Map 9.30), may be considered, and defined as such, to include all major gas trunk pipelines, land based LNG terminals and FSRUs.

Map 9.30 **The Expanded South Corridor**

NB: The TANAP, TAP and Turk Stream have been completed, while BRUA and IGB are still under construction. The IAP, the IGI Poseidon in connection with East Med pipeline and the Vertical Corridor and the IGF are still in the study phase. Blue Stream and Trans Balkan are existing pipelines.

Source: IENE

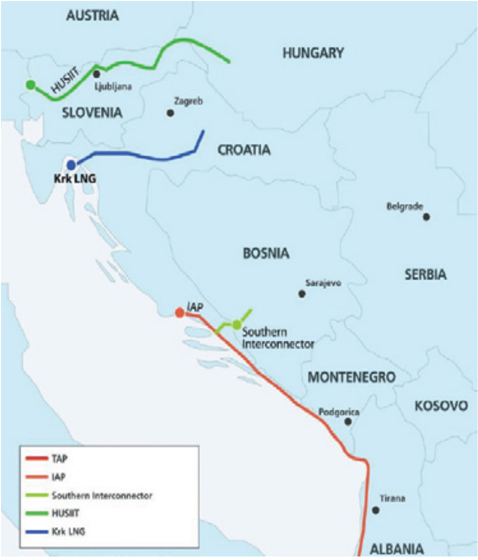
Concerning countries heavily dependent on coal for power generation, according to the Economic and Investment Plan for the West Balkans EU , the construction of the following gas infrastructure will facilitate the transition from coal:

- The construction of Fier-Vlora gas pipeline in Albania (see Albania Section) and the Ionian-Adriatic pipeline along the coast should be prioritised, facilitating a major diversification of the sources of gas supply to the Western Balkans region and beyond,
- The Gas-Interconnector Bosnia and Herzegovina – Croatia, complementing the above diversification, and increasing the potential and diversification of the existing gas distribution system in the country, must be completed,
- The North Macedonia – Kosovo Gas Interconnection should be seen in context of the already under North Macedonia – Greece interconnector. Hence, every effort should be made to develop this new interconnection.
- The North Macedonia – Serbia Gas Interconnection, which should soon enter construction stage.

For those countries which are heavily reliant on coal, the move away from coal in the short to medium term means a switch to modern, low emission gas infrastructure. This can offer the region a widely available, secure and affordable source of energy that will keep the countries involved competitive at international level, while significantly improving air quality and lowering emissions. At the heart of new gas infrastructure are new pipelines, including the extension of the Trans Adriatic Pipeline, which could offer an opportunity for diversifying the gas sources of the European market and thus bring gas to the region to speed-up transition from coal to clean energy production. It goes without saying that any new pipeline in the Western Balkans must fully respect EU rules, in line with the Energy Community Treaty and be able to demonstrate its long-term viability. A growing global role of liquefied natural gas (LNG) should also be considered as an opportunity to diversify gas supplies in the region via LNG terminals in Greece and Croatia at this stage.
In the longer term, these gas infrastructure investments will provide the basis for the next step in environmental protection, as they will allow for the introduction of decarbonised gas once available and competitive, allowing further reductions in carbon dioxide and the impact of air pollution. Therefore, these investments will future-proof the region's energy supply.

Especially the West Balkan region, currently relying heavily on Russian gas, may transform into an interconnected gas trading area in the following years. This transformation can be facilitated through the operation of the Croatian LNG Terminal at Krk (which commenced operation early in 2020) and cross border pipeline projects between Hungary, Slovenia and Italy.

Map 9.31 **West Balkan Infrastructure Projects**



Source: BH-Gas, ENTSOG,FGSZ, Pilnarco, Plinovodi, Snam Rete, TAP

Any future prospects of market development in the West Balkan region will largely depend on the completion of infrastructure projects. Some of the more ambitious project like the Ionian Adriatic Pipeline (IAP) may not be implemented but the region should nevertheless have sufficient supply in the coming year.

The bidirectional IAP pipe is planned to connect the existing Croatian infrastructure and the proposed Krk LNG terminal, via Montenegro and Albania, with the Trans Adriatic Pipeline, which will deliver Azerbaijani gas to Italy through Turkey, Greece and Albania. The 511km-long IAP pipe could supply Albania with 1 bcma, Montenegro with 0,5 bcma, Bosnia and Herzegovina with 1 bcma and Croatia with 2,5 bcma (total capacity around 5 bcma). Intended flow would be south-north, although it would be bi-directional. A branch could go to Bosnia and Herzegovina and provide enough supply for the gasification of Western Balkans. IAP alone would need to place gas outside the immediate IAP market envelope, and this would imply the need for interconnector capacity with Slovenia and/or Hungary, turning it into what it really is, a regional transit system.

An equally important project in regional terms is the planned East Med pipeline, which, on the 2nd of January 2020, reached a critical point in its development history when the first major intergovernmental agreement for its realization was signed in Athens by the energy ministers of Greece, Cyprus and Israel and with the Italian government's backing. The East Med pipeline is considered by the European Union as a major new gas artery which will help to diversify European gas supply and hence it has been included in the Projects of Common Interest (PCI) thus ensuring the necessary funding for its study, including the FEED phase. There is no doubt that the agreements signed on January 2 in Athens form a turning point in the project's development phase. Efforts will now focus in attracting the necessary investor interest and secure binding gas sale agreements with Energean customers which is necessary in order to reach an FID before the end of 2022.

Especially during the years 2019-2020, European Union's leaders appear to have totally embraced a Climate Action approach in laying out the bloc's latest energy strategy, as this is spelled out in the "Green New Deal for Europe". Consequently, there is an open war has been declared against fossil fuels. Natural Gas has been declared persona-non-grata in total disregard to until recently stated policies and agreed commitments (e.g. PCI gas projects, drive to encourage wide scale use of gas for domestic and industrial needs, etc.). On November 14, 2019, EIB decided to suspend all funding to fossil fuels projects, including natural gas, as early as the end of 2020. As EIB is the foremost EU lender and a trend setter at that, it is expected that the Bank's example will soon be followed by EBRD, but also by major commercial banks across Europe.

EIB's decision is bound to have a very negative impact on the development of natural gas projects in the SE European region, where approximately €40bn is required over the next 10 years for hundreds of new projects in the country core group which IENE tracks. As already mentioned, unlike the rest of Europe, gas infrastructure in SE European countries is still under development, especially as natural gas has until recently been widely promoted by the EC and governments as substitute to coal powered generation. EIB's decision has come under sharp criticism since it not only ignores the geopolitical realities in the region related to natural gas exploration, production and utilization but is also undermining economic development prospects in this poorer part of Europe. In addition, EIB's decision, a mirror of EC thinking, is highly discriminatory against SE Europe.

On the 14th of January 2021, EU launched a public consultation[58] on the 5th list of candidate Projects of Common Interest (PCI) in electricity and gas as shown in Tables 9.53 and 9.54. The 5th PCI list will be adopted by the European Commission by the end of 2021 under the existing regulation on Trans-European Energy Networks (TEN-E).

Table 9.53 **List of candidate PCI gas projects in SE Europe**

TYNDP Project numb	Name of the project	Countries	PCI Priority Corridors	Current phase of the project	FIRST Project date of commissioning	LAST Project date of commissioning
LNG-A-1146	Cyprus Gas2EU	Cyprus	SGC	Detailed Engineering & Permitting are the main ongoing tasks. Overall Project Implementn period 24m	2022	2022
LNG-N-62	LNG terminal in northern Greece / Alexandroupolis - LNG Section	Greece	NSI East Gas	Preparing for FID. Concluding construction contracts award and Project Financing	2022	2022
LNG-N-815	LNG terminal Krk 2nd phase	Croatia	NSI East Gas	Market development	2027	2027
TRA-A-10	Poseidon Pipeline (only offshore part applying)	Greece	SGC	Construction tenders	2022	2025
TRA-A-1322	Development on the Romanian territory of the NTS (BG-RO-HU-AT)-Phase II	Romania	NSI East Gas	Permitting	2022	2022
TRA-A-302	Interconnection Croatia-Bosnia and Herzegovina (South)	Croatia	NSI East Gas;#SGC	Basic Design for the section Imotski-HR/BH border	2023	2023
TRA-A-330	EastMed Pipeline	Greece	SGC	Permitting	2025	2025
TRA-A-362	Development on the Romanian territory of the Southern Transmission Corridor	Romania	NSI East Gas	Contract awarding	2021	2021
TRA-A-377	Romanian-Hungarian reverse flow Hungarian section 2nd stage	Hungary	NSI East Gas	Preparing the next non binding capacity market survey	2022	2022
TRA-A-654	Eastring - Bulgaria	Bulgaria	NSI East Gas	FEED	2025	2030
TRA-A-655	Eastring - Romania	Romania	NSI East Gas	FEED	2025	2030
TRA-A-656	Eastring - Hungary	Hungary	NSI East Gas	FEED	2025	2030
TRA-A-68	Ionian Adriatic Pipeline	Croatia	NSI East Gas;#SGC	Preliminary Design in Montenegro and Albania	2023	2025
TRA-A-70	Interconnection Croatia/Serbia (Slobdnica-Sotin-Bačko Novo Selo)	Croatia	NSI East Gas	Revison of ESIA and Preliminary Design for Sotin-Bačko Novo Selo	2023	2027
TRA-A-782	TANAP X- Expansion of Trans Anatolian Natural Gas Pipeline Projec	Turkey	SGC	Desktop study on blending hydrogen with natural gas and its transpo	2025	2025
TRA-F-1276	Compressor station at Nea Messimvria (3rd unit)	Greece	SGC	Construction	2022	2022
TRA-F-298	Modernization and rehabilitation of the Bulgarian GTS	Bulgaria	NSI East Gas	Construction	2021	2024
TRA-F-378	Interconnector Greece-Bulgaria (IGB Project)	Bulgaria	NSI East Gas	Construction	2020	2025

Source: European Commission

TRA-N-1058	LNG Evacuation Pipeline Kozarac-Slobodnica	Croatia	NSI East Gas	Main Design	2027	2027
TRA-N-108	M3 pipeline reconstruction from CS Ajdovščina to Šempeter/Gorizia	Slovenia	NSI East Gas	Extended EIA. Ready for FEED, FEED end date 1.12.2023	2025	2025
TRA-N-1090	Metering and Regulating Station at Alexandroupoli	Greece	NSI East Gas	Basic Design Study, Permitting and Land Acquisition Procedure	2022	2022
TRA-N-1091	Metering and Regulating station at Megalopoli	Greece	SGC	On hold	2025	2025
TRA-N-1092	Metering and Regulating Station at UGS South Kavala	Greece	NSI East Gas	Ongoing tender procedure for the UGS S. Kavala (UGS-N-385)	2023	2023
TRA-N-112	R15/1 Pince - Lendava - Kidričevo	Slovenia	NSI East Gas	National spatial plan R15/1 for sections Lendava-Ljutomer and Ljutomer-Kidričevo is in progress.	2023	2025
TRA-N-1278	Compressor station at Ambelia	Greece	SGC	Open Tender Procedure for EPC contract	2023	2023
TRA-N-128	Compressor Station Kipi	Greece	NSI East Gas	Awarding procedure for the Basic Design study	2024	2024
TRA-N-137	Interconnection Bulgaria - Serbia	Bulgaria	NSI East Gas	FEED; Permitting Phase	2022	2022
TRA-N-224	Gaspipeline Brod - Zenica	Bosnia Herzegovina	NSI East Gas	Expectation of an agreement between the BiH entities on the prioritisation of the Project	2025	2025
TRA-N-325	Slovenian-Hungarian interconnector	Hungary	NSI East Gas	CBA, CBCA preparation	2023	2025
TRA-N-389	Upgrade of Murfeld/Ceršak interconnection (M1/3 Interconnection Ceršak)	Slovenia	NSI East Gas	Ready for FEED. FEED end date 1. 7. 2022.	2023	2023
TRA-N-390	Upgrade of Rogatec interconnection (M1A/1 Interconnection Rogatec)	Slovenia	NSI East Gas	National spatial plan - will be adopted in 2021. Ready for FEED - FEED end date 1. 7. 2022.	2021	2023
TRA-N-524	Enhancement of Transmission Capacity of Slovak-Hungarian interconnector	Hungary	NSI East Gas	FEED	2022	2022
TRA-N-63	LNG terminal in northern Greece / Alexandroupolis - Pipeline Section	Greece	NSI East Gas	Preparing for FID, Concluding construction contracts award and Project Financing	2022	2022
TRA-N-66	Interconnection Croatia -Bosnia and Herzegovina (Slobodnica- Bosanski Brod)	Croatia	NSI East Gas	Prepering request for the new ESIA	2025	2025
TRA-N-75	LNG evacuation pipeline Zlobin-Bosiljevo-Sisak-Kozarac	Croatia	NSI East Gas	Obtaining the Building Permits	2027	2027
TRA-N-810	TAP Expansion	Greece	SGC	Submission of the Project Proposal for the NRAs approval, as per Article 28(1) EU CAM NC.	2025	2025
TRA-N-851	Southern Interconnection pipeline BiH/CRO	Bosnia Herzegovina	SGC	Policy/local legislation; Tender Dossier; TD Revision through JASPERS;	2023	2023
TRA-N-86	Interconnection Croatia/Slovenia (Lučko - Zabok - Jezerišće - Sotla)	Croatia	NSI East Gas	Issuing Building Permit for section Lučko - Zabok	2021	2023
TRA-N-92	CS Ajdovščina, 1st phase of upgrade	Slovenia	NSI East Gas	Ready for FEED. FEED end date 1.12.2023.	2025	2025
TRA-N-94	CS Kidričevo, 2nd phase of upgrade	Slovenia	NSI East Gas	Ready for FEED. FEED end date 1. 7. 2022.	2023	2023
TRA-N-959	Further enlargement of the BG—RO—HU—AT transmission corridor (BRUA) phase 3	Romania	NSI East Gas	Preparation for feasibility study	2023	2023
TRA-N-971	Compressor station at Nea Messimvria	Greece	SGC	Studies (Basic Design and ESIA)	2023	2023

Source: European Commission

A short description of major gas infrastructure projects per country in the SEE region follows.

In **Albania**, the main natural gas infrastructure projects elaborated by the Albanian government include:

- Construction of a pipeline to supply CCGT Vlora power plant (Fier – Vlora gas pipeline),
- Ionian Adriatic Pipeline (IAP) along the coast that connects Albania, Montenegro, Croatia, Bosnia Herzegovina,
- ALKOGAP, the interconnector which could connect Albania and Kosovo.

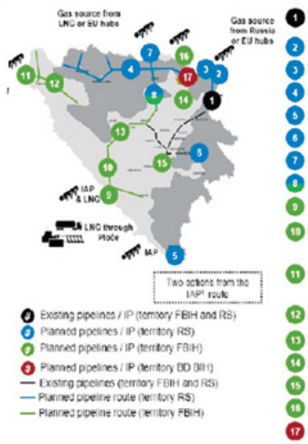
The Fier – Vlora gas pipeline, and especially IAP, will be prioritised as it facilitates a major diversification of the sources of gas supply to the Western Balkans region and beyond[59].

In January of 2020, Albania's infrastructure ministry announced a bid invitation for reviving the idled Vlora thermal power plant and for the construction of a gas pipeline between Vlora and Fier (potential TAP exit point) to link the plant to the Trans Adriatic Pipeline (TAP). The construction of the $130 million Vlora Gas-fired Thermal Power Plant - TPP (97 MW) was completed in 2011 but the plant was never actually put into operation over technical issues. It is expected that TPP Vlore could cover 20 % of Albania's electricity deficit.

In **Bosnia and Herzegovina** there is only one gas interconnection with Serbia. The internal existing gas transmission pipeline connects the interconnection point with cities such as Sarajevo, Visoko and Zenica (Figure 9.150). This single cross-border point and only one pipeline does not allow any possibility for diversified gas supplies to the country and the provision of certain level of Security of Supply (SoS) or to be able to attract potential customers.

Figure 9.150 **Actual status and plan for gas pipelines in Bosnia and Herzegovina**

Project name	Direction		Techn. capacity (bcm/year)	
	From	To	Import	Export
Interconnection Zvornik	SRB	BIH	0,6	-
Šepak - Bijeljina	Šepak	Bijeljina	1,5	-
Interconnection with Serbia in Bijeljina (Novo Selo) area	SRB	BIH	2,0	-
Gas pipeline (Bijeljina – Banja Luka and further)	SRB	BIH	2,0	-
Gasification of Trebinje from IAP	IAP	BIH	n/a	n/a
Gasification of Gornjeg Podrinja	Gasification from an existing system		n/a	n/a
Slobodnica – Brod, northern interconnection BIH & CRO on CRO territory (TRA-N-000)	CRO	BIH	5,6	5,6
Brod - Zenica, northern interconnection BIH & CRO on BIH territory (TRA-N-224)	Brod	Zenica	1,2	1,2
Zagvozd – Imotski – Posušje, Southern interconnection BIH & CRO on CRO territory (TRA-N-302)	CRO	BIH	2,0	2,0
Posušje – Novi Travnik / Travnik with a Mostar section, Southern interconnection BIH & CRO on BIH territory (TRA-N-851)	Posušje	Travnik	1,2	-
Rakovica – Tržac, Western interconnection BIH & CRO on CRO territory (TRA-N-912)	CRO	BIH	0,9	-
Tržac – B. Krupa with sections for Bihać and Velika Kladuša, Western interconnection BIH & CRO on BIH territory (I. phase)	Tržac	B. Krupa & sections	0,9	-
Western interconnection BIH / CRO with gas pipelines B. Krupa – Ključ (II phase) & Pećigrad – Bužim (III phase)	B. Krupa	Ključ	n/a	n/a
	Pećigrad	Bužim	n/a	n/a
Travnik - G. Vakuf & Travnik – Jajce	Expansion of existing infrastructure		n/a	n/a
Underground gas storage near salt caverns in Tetima	+ pipeline Kladanj-Tuzla-Tetima		Min. capacity 60mcm	
Gasification of Gornje Podrinje	Gasification from an existing system		n/a	n/a
Gasification of Orašje	CRO	BIH	n/a	n/a
Gasification of Brčko District of Bosnia and Herzegovina	Connection in line with entity plans			



Source: IENE

As the strategic vision of Bosnia and Herzegovina is a systematic vertical linkage to the Croatian gas pipeline system (gas ring formation and gas supply from multiple sources: LNG, IAP or in general EU gas hubs), there is a proposed pipeline connecting Bosnia and Herzegovina and Croatia which is expected to become operational in 2023, according to a tender for an environmental impact study and feasibility study issued by the Bosnian grid operator BH-Gas in June 2019. The new 162 km-long pipeline will run from inland Novi Travnik to Posusje at the border with a leg to Mostar. Croatia's Plinacro will also need to construct a connection to the Bosnian border from Split via Zagvozd and Imotski. The new pipeline, called Southern Interconnection, will enable greater Security of Supply and supply

[59] Economic and Investment Plan for the Western Balkans EU Oct-2020 /ec.europa.eu/commission/presscorner/detail/en/ip_20_1811

diversification for Bosnia-Herzegovina by linking its grid to the Croatian LNG terminal in Krk and to natural gas storage facilities in neighbouring countries. Pipeline development plans for Bosnia and Herzegovina must follow planned cross-border projects relevant for Bosnia and Herzegovina and part of SE Europe. The goal for both entities is to increase the importance of natural gas as an energy source in the economy with the aim of strengthening the integration of gas market and Security of Supply.

In **Turkey**, the total length of the natural gas transmission grid reached 15.547 km and is operated by BOTAŞ. Third party access to transmission network is regulated. The shippers apply to BOTAŞ in the Framework of BOTAŞ Transmission Network Operation Principles. Natural gas quantities are delivered into the transmission pipeline network at 13 entry points. The distribution network consists of 137.535 km low pressure pipelines[60]. Natural gas distribution was conducted by 72 distribution companies in 510 cities of 81 provinces. The distribution network reached the length of 12.875 km steel pipelines, 88.602 km polyethylene pipelines and 36.058 km service lines. Some 66 million Turkish citizens have access to natural gas and 50,6 million are active consumers. The total number of individual consumers in 2018 reached 15.400.892 and the number of eligible consumers stood at 604.664[61]. The threshold to become an eligible consumer is 75.000 cubic meters consumption per year.

Map 9.32 **Turkey's Natural Gas Transmission System**

Source: Botas, GAZBIR

The first international natural gas pipeline connection of Turkey, the Russia-Turkey Trans-Balkan Pipeline with an initial capacity of 6 bcma was inaugurated in 1987 and as already mentioned Gazprom ceased to supply through this line as of January 2020, as TurkStream pipeline went online. The Blue Stream Pipeline with 16 bcma capacity is since 2003 operational and runs 370 km from Izobilnoye to Djubga onshore in the Russian Federation and 390 km offshore in Black Sea. In Turkey it continues from Durusu measuring station near Samsun 501 km via Amasya, Çorum and Kırıkkale to Ankara. The line has one compressor station in Çorum. The Iran- Turkey (Eastern Anatolia) pipeline with 10 bcma capacity is operational since 2001. It has a length of 1.491 km in Turkey from Gürbulak border crossing via Erzurum, Sivas, Kayseri to Ankara. The line has four compressor stations in Doğubayazıt, Erzincan, Sivas and Kırşehir, while the measuring station is in Bazargan on the Iranian side of the border. The Baku-Tbilisi-Erzurum Pipeline with an initial capacity of 7 bcma became operational in 2007. The 690 km long (South Caucasus Pipeline) is connected with a 226 km stretch from the Georgian border to Erzurum and to the Turkish transmission system. There is a measuring station at the entry side at Türkgözü and a compressor station in Hanak near Ardahan.

The interconnector Turkey-Greece ITG with a length of 296 km connects the Turkish and Greek transmission networks between Karacabey and Komotini. The pipeline has a capacity of 7 bcma but is grossly underutilized with less than 1,0 bcma deliveries.

The Trans-Anatolia Pipeline TANAP with a capacity of 16 bcma stretches 1.850 km from the Turkey-Georgia border to the Greek border. At the Georgian border it is connected to the extended South Caucasus Pipeline and at the Greek border to the Trans-Adriatic Pipeline TAP. TANAP has two measuring stations at the borders and two at the off-take points in Eskişehir and in Thrace. Two compressor stations have been erected near entry point at the East and at the off-take point in Eskişehir. The pipeline supplied first gas into the Turkish grid in June 2018 and was connected to TAP in November 2019.

[60] BOTAŞ, 2018 Natural Gas Distribution Sector Report, Natural Gas Distribution Companies Association of Turkey GAZBIR 2019.
[61] 2018 Natural Gas Distribution Sector Report, GAZBIR 2019.

The TurkStream Pipeline starts at Russkaya compressor station near Anapa on the Russian coast in the Black Sea and runs over 930 km in the Black Sea to reach the Turkish coast at Kıyıköy in northwest of Istanbul. TurkStream consists of two strings each with 15,75 bcma capacity. One line is connected to the Turkish grid in Lüleburgaz and delivers the gas previously coming through the Trans-Balkan Line since January 2020. The second line is planned to supply South and Central Europe with Russian gas via Bulgaria, Serbia and Hungary. Bulgaria, Greece and North Macedonia are receiving gas from TurkStream since January 2020.

Map 9.33 **Natural gas import and export infrastructure of Turkey**

Source: : BOTAŞ

Concerning the LNG regasification terminal at Marmara Ereğlisi, after the extension of its jetty, the terminal received in June 2019 the first Q-Flex LNG carrier. In late 2006, thanks to a private sector investment of the Çolakoğlu Group, EgeGaz LNG regasification terminal in Aliağa, north of Izmir, went into service (Table 9.55 summarizes Turkey's LNG terminal characteristics). Egegaz terminal may receive up to Q-Max class LNG vessels.

Table 9.55 **Liquified natural gas import infrastructure**

Terminal	Type	Capacity (bcma)	Storage capacity (cubic meters)	Sendout capacity (mcm/d)
Botaş Marmara Ereğlisi	Onshore LNG	6.0	255,000	37
Egegaz Aliağa	Onshore LNG	6.0	280,000	40
Etki Aliağa	FSRU	5.3	170,000	28
Botaş Dörtyol	FSRU	5.3	263,000	20
Botaş Saros	FSRU	under implementation		

Source: BOTAŞ, Egegaz, Etki FSRU

The Etki Aliağa FSRU terminal is owned by the private sector companies Kalyon (50%), Kolin (30%) and Iska Group (20%) and started its operation in December 2016 with the chartered FSRU Neptune (former GDF Suez Neptune). In July 2019, the new FSRU Turquoise P with 170.000 cubic meters storage capacity, ordered by the owners of the terminal and built at the Ulsan shipyard of Hyundai in South Korea replaced Neptune. BOTAŞ Dörtyol terminal started its operation in February 2018 with the chartered MOL FSRU Challenger with 263.000 cubic meter capacity. BOTAŞ is investing 450 mill TL for Saros FSRU jetty and network connection until 2021 and will realize remaining investments of 45 mill TL at Dörtyol FSRU until 2021. BOTAŞ is also investing 1.4 bill TL for the procurement of a new FSRU facility.

However, at the same time there is no appetite in the industry to invest in new natural gas fired power plants. Transmission and distribution network investments will continue in order to increase the access to natural gas. BOTAŞ is investing 2,6 bill TL in new transmission lines until 2023 and 1,5 bill for rehabilitation of existing lines and infrastructure until 2024. The distribution companies spent 1,7 bill TL for network investments in 2018 and planned to spend a further 1,1 bill TL in 2019[62]. In the coming years, we may expect yearly distribution investments of around 1 bill TL.

Concerning **Greece's** gas infrastructure, a brief description of the National Natural Gas Transmission System (NNGTS) can be found in IENE's South East Europe Energy Outlook 2016/2017. The most important developments in Natural Gas Infrastructure in Greece can be summarized as follows:

- Commissioning of the 2nd Phase Upgrade of the Revythoussa LNG Terminal which took place in the beginning of 2019 (storage capacity increased to 225.000 m^3 LNG),
- In January 2021, first natural gas volumes were delivered to NNGTS through the TAP pipeline at the new Entry Point at Nea Mesimvria.
- The construction of the IGB pipeline (a 182 km pipeline linking Komotini with Stara Zagora in Bulgaria – capacity 3 bcma expandable to 5 bcma) commenced in October 2019. Commissioning of the pipeline is expected by mid-2021. DESFA has already planned the connection of NNGTS to IGB pipeline in the latest TYNDP.
- The binding phase of Market Test for the Alexandoupolis offshore LNG Terminal (5,5 bcma capacity) was concluded successfully in March 2020, reaching binding offers of 2,6 bcma for up to 15 years. FID was expected by the end of February 2021 and commissioning by 2023. DESFA has already planned the connection of NNGTS to FRSU Alexandroupolis in the latest TYNDP.

Concerning LNG infrastructure, it is worth noting that on December 30, 2018, Greece's Revithoussa LNG terminal, following an agreement between Cheniere and DEPA, welcomed the first US LNG cargo at its newly build 3rd tank of 95.000-m^3 storage capacity. Thus, the Revithoussa LNG terminal opened up the way for new prospects in gas supply by differentiating energy sources and enhancing security of supply in SE Europe, enabling Greece to pitch its claim as a regional gas hub.

Regarding the planned Alexandroupolis FSRU in northern Greece, Gastrade, the promoter of the project, successfully launched the binding second-round market test for annual capacity reservations. The FSRU will have a nominal regasification and send-out capacity of 5,5 bcma and a peak technical regasification and send-out capacity of 22,8 million cubic meters per day. One further FSRU project in Greece is now in the planning stage and it is promoted by Motor Oil Hellas, a major refining and oil marketing group. This latest FSRU project, which received approval by RAE on March 5, 2019, is to be located offshore in the Agioi Theodoroi area, next to Motor Oil's refinery. The capacity of the FSRU tank will be 135.000-170.000 m^3, while its regasification capacity peak is expected to be 470.000 Nm^3 /h. (See Box).

Dioriga Gas FSRU Position

The project, proposed and promoted by the Motor Oil Hellas group, consists of a Floating Storage Regasification Unit (FSRU) to be anchored at a distance of 200 m offshore, south-west of Motor Oil's refinery in Agioi Theodoroi near Corinth, located 65 km west from Athens. The project, which in March 2019 obtained a licence from Greece's Regulatory Energy Authority (RAE) as Independent Natural Gas System License, will be connected to the National Natural Gas

[62] 2018 Natural Gas Distribution Sector Report, GAZBIR 2019.

[63] http://www.gastrade.gr/en/the-company/news-press-releases/the-binding-phase-of-the-market-test-for-the-alexandroupolis-offshore-lng-terminal-was-concluded-successfully.aspx

System (NNGS) via an offshore/onshore pipeline (that will be constructed with hydrogen blending technology), while it has been included in DESFA's 10-year NNGS Development Plan (2021-2030).

The planned storage capacity of the unit is up to 210,000 m^3, with regasification capacity of 132,000 MWhs/d and an annual projected demand of 2.5 bcm. The project will strengthen the security of gas supply at national and European level and will constitute a new NNGS entry point. Upon completion, Dioryga FSRU will enhance the anticipated interconnections of the NNGS with neighboring gas systems and will provide further access to the countries of SE Europe.

The project will also give extra benefits to the end consumer, since it will provide additional liquidity to the LNG market (lower procurement prices) and contribute to the decongestion of the LNG terminal at Revithoussa, of which the first indications emerged in the last quarter of 2019. Moreover, the project will act as:

- Complementary to the LNG terminal at Revithoussa (proximity - double unloadings of large LNG vessels of Q-Max size);
- Optimum supply point for the natural gas distribution network of DEDA (Public Gas Distribution Network), which provides LNG supply to the cities of Patras, Agrinio and Pyrgos;
- Key enabler of the development of the emerging Marine LNG & Small-Scale LNG market.

The key milestones of the project as follows:

- 2021: Commercial Development (Market Test) Licensing (Construction Permit, EIA Study, Safety Studies, Approvals, Technical Studies etc.)Detailed Engineering (FSRU (Shipyard, Classification; Marine), Ship to Shore interface, NG Onshore Pipeline Routing, M/R Station)
- 2022-2023: Implementation Procurement & Construction
- 2023: Commissioning & Operation Operation Permit (EIA Permit, Building Permit, Technical Documentation, Safety/Fire Fighting Studies, Navigation Study, Equipment Certificates etc.)

Source: Motor Oil Hellas

In **Bulgaria**, the national gas transmission network is built in a ring-shaped form consisting of high-pressure gas pipelines with a total length of 1.700 km and three compressor stations with installed capacity of 49 MW. Its technical transport capacity amounts to 7,4 bcma, and the maximum working pressure is 54 bar. The transit gas transmission network comprises high pressure gas pipelines of 945 km total length, six compressor stations with total installed capacity of 214 MW. The total technical capacity for natural gas transit transmission amounts to 18,7 bcma and the maximum working pressure is 54 bar. The development of low-pressure gas distribution network started in the last decade and its length is over 3.500 km. (See Map 9.34).

Map 9.34 **Bulgaria's current gas infrastructure**

Source: Bulgartransgaz

The interconnections with Greece and Serbia, as well as increasing Chiren's capacity are included in the list of EU Projects of Common Interest (PCI) and have received grant support for feasibility studies and construction works under the European Energy Programme for Recovery, the European Fund for Regional Development, and the Connecting Europe Facility. Finally, the Interconnector Bulgaria – Romania (IBR) is a 25 km length pipeline, which is a part of the Vertical Gas Corridor.

In **Croatia**, the total length of the gas transport system at the end of 2019 was 2.531 km, of which 952 km were main gas pipelines under a nominal pressure of 75 bars, and 1.579 km gas pipelines under a nominal pressure of 50 bars. The gas is received into the transport system from nine connection points at entry measuring stations, of which six connection points serve for receiving gas from production fields on the territory of the Republic of Croatia, two connection points are international connection points and serve for receiving gas from import routes, while one is for withdrawing gas from the Okoli underground gas storage facility (UGS Okoli). Gas is delivered to transmission system users through 157 exit metering/regulation stations. The total length of all gas distribution systems in Croatia at the end of 2018 amounted to 18.067 km. Major planned new projects are related to gas exploration, development of an LNG terminal, the expansion of the gas transmission network and development of a new underground gas storage facility.

Croatia's FSRU Project

LNG Croatia LLC is a company established for the purpose of building and operating the infrastructure necessary for receiving, storing and regasifying liquid natural gas. In accordance with planned deadlines for the construction of the floating LNG terminal on the Island of Krk, a Final Investment Decision was adopted on 31st January 2019.

Initially, Croatia had been planning to construct a 6 bcma onshore terminal at Krk but insufficient market interest and high costs prompted project promoter LNG Croatia LLC, a joint venture of Plinacro and incumbent HEP, to downsize the proposed technical capacity. As a result, a more feasible floating storage and regasification unit (FSRU) was greenlighted in 2019. Hungary offered to buy a 26% stake in the FSRU but the Croatian government anticipated the acquisition by Hungarian companies buying itself regasification capacity at the proposed terminal. Hungary rejected that proposal as it found the price, including the regasification tariff and transport fees, uncompetitive with Russian gas supplies. Hungarian companies refrained from booking capacity due to lack of clarity around the project framework and the high total costs of getting the gas to Hungary.
The procurement procedure of the floating, storage, and regasification unit (FSRU vessel) was carried out in November 2018. The bid from Golar company was evaluated as the most economically advantageous, which offered a new conversion of the existing LNG tanker to the FSRU vessel worth EUR 159,6 million. It is an LNG carrier, which was built in 2005 and which sails under the name "Golar Viking". In 2019 LNG Croatia LLC completed the binding process for booking the capacity of the LNG terminal (Open Season procedure), which resulted in capacity booking of the terminal in the amount of 0,52 bcma.

In accordance with the conducted procurement procedures the total capital expenditures of the project have been reduced to EUR 233,6 million (the initial planned investment amounted to EUR 383 million). In addition to an already approved grant from the European Commission of EUR 101,4 million, the Government of the Republic of Croatia decided to finance the first phase of the project for the floating LNG terminal on the Island of Krk with which a grant of EUR 100 million. The remaining part of the required capital expenses, i.e. EUR 32,2 million, was to be provided by the shareholders of LNG Croatia LLC through increase in equity.

In January 2019, the Croatian government decided that state-owned companies must provide around 58% of the required funds as low market interest in the binding open season for regasification capacity did not justify realisation of the project. HEP and national oil and gas producer INA booked a total of 520 million cubic metres mcm per annum binding capacity, while two other companies booked 300mcm per annum of conditional, non-binding capacity. In parallel, Qatar's PowerGlobe also booked up to 1,3 Bcma in the 2,6 Bcma in Croatia LNG terminal out to 2035.

Eventually, Croatia's flagship gas project, the downsized 2,6 bcma LNG terminal, came online on the 1st of January[64] 2021, having its full capacity booked for the next few years.

[64] https://www.reuters.com/article/croatia-lng/croatia-kicks-off-lng-terminal-in-north-adriatic-idUKL8N2JC0FN

According to «LNG Hrvatska», the company which runs the project, the terminal capacities have been sold out until October 2023, while for the following four years, until October 2027, the capacity of some 2,1 bcm of gas annually has already been locked in. The new terminal is expected to change supply dynamics in the West Balkan and central European regions. The new terminal would also become a trans-regional infrastructure project as a vertical supply route (North-South Gas Corridor) by linking existing and new infrastructure. Plinacro Gas Transmission System Operator completed the development of the main Croatian gas system. Future system development is related to the development of the regional interconnection pipelines (IAP, neighbouring countries connections) and transmission of gas from the Krk LNG terminal. Most of the pipelines which are in the focus of future development plans are nominated for the EU PCI projects and Energy Community Projects of Mutual Interest - PMI.

Croatia's isolation from neighbouring markets ended in2020 as Plinacro completed the construction of a compressor station on the Croatian-Hungarian border, which has enabled firm export flows along the now bidirectional Dravaszerdahely border point from 16 January. Prior to that Croatia was the only country which had import capacity available on its borders, which was one of the factors limiting trading activity in the market. Due to the lack of export capacity and the proportionally large domestic production, Croatia has remained a balancing market, where shippers were only active on the HROTE-operated balancing and trading platforms in order to balance their physical portfolios. Only Plinacro and balancing group managers are allowed to trade on the HROTE platform. Market participants have been pushing to lift the restriction in recent years, but energy regulator HERA has been reluctant to change the market rules. The HROTE platform has 18 members, which include utilities, suppliers and energy trading houses.

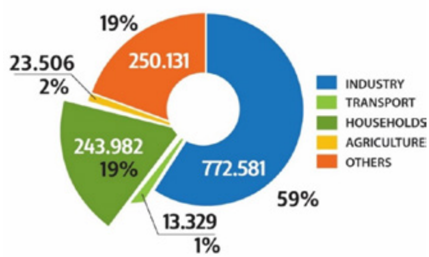
The launch of export capacity on the Croatian-Hungarian border has been part of a set of infrastructure development projects in accordance with EU regulations, which requires interconnectors to be bidirectional across the bloc. Cross-border trading with Hungary may spur liquidity not only in Croatia but also in Slovenia as Slovene shippers are active in Croatia.

In **Serbia**, the length of the Srbijagas-Transportgas transmission system amounted to 2.339 km (95%) in north and central Serbia, while the length of the Yugorosgaz-Transport transmission system is 125 km (5%) in southern Serbia. The natural gas system has one entry point at Hungary's Kiskundorozsma crossing point, with a technical capacity of 4,55 bcma and one exit point at Zvornik for onward delivery of Russian gas to Bosnia & Herzegovina. Srbijagas and Yugorosgaz have undergone the initial unbundling of transmission activities. The two newly established transmission system operators are companies Transportgas Serbia LLC and Yugorosgaz -Transport LLC.

Map 9.35 **Current natural gas transmission network - 2019**

The total distribution network length at the end of 2018 was 18.422 km. The share of the Srbijagas is distribution network in the country's distribution network is 52%. At the end of 2028 there were over 276.581 delivery points of which 64 inside the transmission and 276.517 inside the distribution network. Of these, 262.814 or 95% correspond to households, which is only roughly 10% of all households in Serbia. Average annual consumption of natural gas per connected household in 2018 was 1009 m³.

Figure 9.151 **Final natural gas consumption (1,303.529 bcm) by sector - 2018 (mcm, %)**



Serbia is intensively working on interconnections with neighbouring countries, which will enable gas supplies from new sources. Interconnection with Bulgaria is crucial through the construction of the Nis-Dimitrovgrad-Sofia gas pipeline. The Bulgaria-Serbia Interconnector (IBS) is a priority project agreed under SESEC High Level Group as it will improve Security of Supply and diversification of gas imports in SE Europe. The interconnector is a 170km pipeline with initial capacity at 1,8 bcma, expandable to 4,5 bcma and it will be bi-directional. It is expected to be completed by mid 2022 at the latest, along with the Greece-Bulgaria Interconnection (IGB), connecting Serbia to the Southern Gas Corridor and opening up opportunities for the future supply of Caspian gas via the TANAP and TAP pipelines, as well as the regional LNG terminals.

In addition to the TANAP and TAP pipelines, whose capacity is limited and already "sold out", the Turkish Stream is a realistically promising option. In June 2017, a Road Map was signed between the Ministry of Mining and Energy and Gazprom on the implementation of the project for the construction of the main transport gas pipeline on the territory of the Republic of Serbia from the border with the Republic of Bulgaria (Zajecar) to the border with Hungary (Horgos) and, if necessary, with other countries that are bordering with the Republic of Serbia. The joint project company Gastrans LLC Novi Sad is the project developer and 95% of its activity takes place in Serbia. The "Serbian Stream" gas pipeline is just over 400 kilometres long, the projected pressure is 75 bar, the pipe diameter is 1.220 millimetres and gas transportation capacity is 12,87 bcma. This pipeline is operational since early 2021 and is a continuation of the Turkish Stream pipeline. This project is of strategic importance to Serbia, while the supporting infrastructure will be developed in 2020/21, including compressor stations and three "exits". Bulgaria is thus expected to be the main hub and transit route for Russian gas exported via Turkey when the second string of the 15,75 bcm/year Turkish Stream pipeline is completed.

Implementation of the Bulgaria-Serbia-Hungary main gas pipeline project will significantly increase the level of energy security both in Serbia and the region. On 21 February 2020, the Serbian Energy Agency Council adopted a Decision issuing a certificate to Gastrans LLC as an independent natural gas transmission operator. Srbijagas-Transportgas is creating preconditions for connection to the neighbouring countries network. In addition to the Nis-Sofia interconnector there are plans to build interconnections with Romania (Mokrin-Arad - 1 bcm) and Croatia (Futog – Sotin -1,5 bcm).

Table 9.56 **Technical characteristics of the natural gas transmission system – 2018**

Transmission system characteristics	Srbijagas	Yugorosgaz
Capacity	= 18 mil m³/day	= 2.2 mil m³/day
Pressure	16-75 bar	16-55 bar
Length	2339 km	125 km
Diameter	DN 150 - DN 750	DN 168 - DN530
Number of entries	13	1
Number of exits	248	5
Interconnector to B&H	1	/
Natural gas storage	1	/

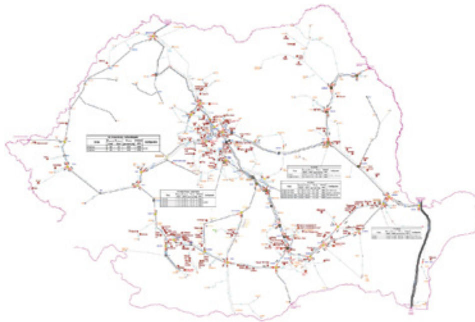
The Bulgaria (Sofia)–Serbia (Nis) Interconnector is one of the priority projects between the two countries. Initially, the interconnector pipeline is expected to deliver 1,8 bcma of natural gas. The Nis-Sofia interconnector in the length of 171 km is planned to be operational by mid-2022. The European Union, through its grants, is contributing to the financing of the project, and 49,6 million Euros has been committed to Serbia. The overall development of the Nis-Sofia transport system, which will provide the full capacity of reverse transmission of natural gas (2,7 bcm from Serbia to Bulgaria and 3,2 bcm from Bulgaria to Serbia), requires an additional 208 mil. Euros.

In **Romania,** the National Gas Transmission System is a radial-ring system interconnected with the starting points in the deposit area of Transylvania, Oltenia and Muntenia East, and the destination area of Bucharest-Ploiești, Moldova, Oltenia and Central and North Transylvania. Natural gas is transported by gas pipelines and gas supply connections, a network operating at pressures between 6 and 35 bar. The gas network is connected to Ukraine, Hungary, Bulgaria and Moldova through seven interconnection points:

- Medieșul Aurit entry point with annual import capacity of 4 bcma (42,2 TWh) and regime pressure of 70 bar,
- Isaccea entry point with an annual import capacity of 8,6 bcma (90,73 TWh) and regime pressure of 55 bar,
- Isaccea 1/Orlovka 1 with capacity of 6,8 bcma. Pressure: 49,5 bar at import, 45 bar at export
- Csanadpalota entry and exit point with an annual import capacity of 1,75 bcma (18.46 TWh), 63 bar pressure, an annual export capacity of 0,087 bcma (0.91 TWh) and annual interruptible export capacity of 0,35 bcma (3.69 TWh). As of October 2019, the import capacity grew to 2,2 bcma.After the completion of phase II of the BRUA gas pipeline, the transport capacity towards Hungary will increase to 4,4 bcma.
- Iași-Ungheni exit point, with an annual capacity of 1,5 bcma (15,8 TWh), 50 bar.
- Giurgiu-Ruse entry/exit point, with annual capacity of 1,5 bcma from Romania to Bulgaria and 0,5 bcma from Bulgaria towards Romania. Pressure: 40 bar at export, 30 bar at import.
- Negru Voda 1/ Kardam with a capacity of 6,4 bcma at export, 55 bar pressure.

Romania's maximum annual import capacity is 14,35 bcma (151.39 TWh). The nominal annual export capacity is 1,58 bcma (16.74 TWh). Physical gas export is possible only with Hungary (Csanadpalota), Bulgaria (Giurgiu-Ruse) and Moldova (Iasi-Ungheni).

Map 9.36 **Romania's National Gas System**



Source: Transgaz, 2017

Table 9.57 **Transgaz investment plan 2017-2026**

Interconnection	Status	Commissioning
Interconnection România-Bulgaria	Final Investment Decision (FID)	Dec. 2016
NTS development in North-East Romania	Non-FID, advanced stage	2018
Interconnection of the NTS with the distribution system and reverse flow at Isaccea	Non-FID (PCI 6.15)	2019
New Developments for the Black Sea projects	Non-FID	2019
Development of the NTS on the Romanian territory: BRUA	Phase I: FID (PCI 6.24.2) Phase II: Non-FID, advanced stage (PIC 6.25.7)	2020 2020
Development of the Southern Corridor on the Romanian territory	Non-FID: advanced stage (PCI 6.24.8)	2020
Eastring – Romania	Non-FID (PIC 6.25.1)	2021
Extension of BRUA – phase 3	Non-FID (PCI 6.25.3)	2023

Source: SNAM-BCG [2017], ENPG [2018])

Romania's flagship project in the last 5 years (2015-2020) has been the BRUA (Bulgaria – Romania – Hungary – Austria) pipeline. When complete will create a transnational system linking Bulgaria with Austria, with work centred on Romania. It serves three purposes: modernisation and enhancement of a large section of the Romanian system, provision of more capacity at the Romania-Hungarian border and the transmission of Black Sea gas to the Romanian gas network.

Phase 1 is a new 32-inch pipeline across southern Romania from Podisor to Recas (479 km). It is considered a Security of Supply project (SoS) and required 478,6 mil. Euros, of which 179,3 mil. Euros was financed by the EU. Construction commenced in June 2018 and ended in November 2020. Phase 2 FiD will be taken only if it considered commercially viable.

The project will result in a 4,4 bcma bi-directional capacity at the Romania-Hungary border, and enable Romanian Black Sea gas to be moved to Central Europe. The Capex is estimated at 74,5 mil. Euros but currently there is lack of market interest. Finally Phase 3 (back-up plan for Phase 2) will be implemented in case additional gas volumes require transportation in excess of the volumes shipped West through BRUA stage II.

In **Hungary**, the natural gas Transmission System Operator FGSZ operates 5.874 km of transmission network with a diameter of 80-1400 mm. Eight compressor stations (Beregdaróc, Nemesbikk, Hajdúszoboszló, Városföld, Csanádpalota, Szada, Báta, Mosonmagyaróvár) provide the pressure for the operation of the system at 40-75 bar. The natural gas is delivered at ca 400 delivery stations to the Distribution System Operators (DSO) and to industrial consumers. There are also 17 main junctions (hubs) of the long-distance pipelines. FGSZ also operates the gas interconnectors to all neighbouring countries, except Slovenia, which is in planning phase. The system is operated via six territorial control centres and a national headquarter: the dispatching centre in Siófok. The task is carried out by the National Telemechanical System (NTS), whereas the data transmission is the responsibility of the Supervisory Control And Data Acquisition (SCADA) function.

Map 9.37 **The Hungarian Natural Gas System**[65]

There is circa 84.100 km of distribution pipelines in the country operated by ten licensed DSOs, with ca. 3,26 million distribution pipeline gas meters. There are ca. 3,47 million consumers connected to the natural gas system, out of which 3,26 million are household consumers.

Table 9.58 **Natural Gas Transmission System/Distribution System/Storage Facilities**

	SZÁLLÍTÓVEZETÉKI MŰSZAKI ADATOK TECHNICAL DATA OF TRANSMISSION PIPELINES		ELOSZTÓVEZETÉKI MŰSZAKI ADATOK TECHNICAL DATA OF DISTRIBUTION PIPELINES		TÁROLÓI MŰSZAKI ADATOK TECHNICAL DATA OF STORAGE FACILITIES		
	SZÁLLÍTÓVEZETÉK HOSSZA [KM] LENGTH OF NATURAL GAS TRANSMISSION PIPELINE [KM]	ÁTADÓÁLLOMÁSOK SZÁMA [DB][1] NUMBER OF DELIVERY STATIONS [PCS][1]	ELOSZTÓVEZETÉK HOSSZA DECEMBER 31-ÉN [KM] LENGTH OF DISTRIBUTION PIPELINE AS OF 31 DECEMBER [KM]	ELOSZTÓVEZETÉKI GÁZMÉRŐK SZÁMA DECEMBER 31-ÉN [DB] NUMBER OF DISTRIBUTION PIPELINE GAS METERS AS OF 31 DECEMBER [PCS]	TÁROLÓI MOBIL KAPACITÁS [Mm³] CAPACITY OF STORAGE FACILITY [Mm³]	KITÁROLÁSI KAPACITÁS [Mm³/NAP] WITHDRAWAL CAPACITY [Mm³/DAY]	BETÁROLÁSI KAPACITÁS [Mm³/NAP] INJECTION CAPACITY [Mm³/DAY]
2015	5 873,4	399	83 618,9	3 233 470	6 330,00	78,60	44,65
2016	5 873,4	400	83 732,1	3 236 014	6 330,00	78,60	44,65
2017	5 873,0	400	83 872,7	3 238 675	6 330,00	78,60	44,65
2018	5 873,4	400	84 079,3	3 256 042	6 330,00	78,00	45,30

Source: HEA-FGSZ – Data of the Hungarian Natural Gas System 2018

[65] On October 4, 2019 at 6 a.m., FGSZ took over the operation of the 92 km long natural gas transmission pipeline from MGT Ltd. connecting Hungary to Slovakia thus, the entire, nearly 6000 km long high-pressure natural gas transmission pipeline system of Hungary is now operated by FGSZ. – FGSZ Press Release – 04 October 2019.

FGSZ prepares each year the National Ten-Year Network Development Plan (TYNDP), where it summarizes the completed, ongoing, proposed and conditionally proposed and not proposed projects.

The recently completed projects include:

- Romania-Hungary interconnector project stage I enabling the bi-directional flow of 1,75bcma,
- Enabling bi-directional firm capacity at the SK-HU border with HU>SK 1,75 bcma and SK>HU 1,2 bcma.

The ongoing projects include:

- SK>HU expansion to 0,5 mcm/h firm + 0,3 mcm/h interruptible capacity
- Security of Supply enhancement of North-East Hungary

Proposed projects in the next three years include:

- Hungary > Ukraine upgrade to 0,8 mcm/h firm capacity

Conditionally proposed projects in the next three years include:

- The Romania-Hungary interconnector project stage II conditional to a successful Open Season. This practically depends on the development of Romania is offshore fields.
- Serbia-Hungary interconnector entry capacity stage I with 6bcma and stage II, with 8.5-10 bcma which depends on the development and contractual arrangements on the ongoing TurkStream expansion in Serbia carried out by Gastrans .

Conditionally proposed projects in the next four to ten years include:

- The Hungary > Austria interconnector with 0,9-1,1 bcma capacity in different variations based on a successful capacity auction in 2020,
- Hungary > Slovakia flexible transit,
- Slovenia – Hungary bi-directional Interconnector with 0,4-3,2 bcma capacity in different variations based on a successful capacity auction in 2020.According to the latest development plan by FGSZ, Hungary and Slovenia are planning to construct the new 41km-long interconnector, which may enable up to 0,4 bcma bidirectional flow from October 2023. Available capacity maybe be further increased in the future up to 3,2 bcma, but the implementation of the upgrades will depend on additional works on the Hungarian grid and the consultation between the grid operators.

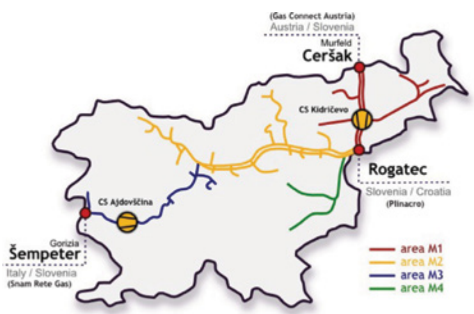
Slovenia' s infrastructure is relatively well interconnected. The main entry point is from Austria and the main exit point is to Croatia, supplemented by a smaller bi-directional link with Italy.

Interconnector Slovenia - Hungary has been recognized as a "Project of Common Interest (PCI) – 2017" and has been included in a list of projects of Central and South Eastern Europe Connectivity and Three Seas Initiative. The project of the interconnection between Hungarian and Slovenian transmission system, as it is reported and described with the PCI status, will enable the bidirectional gas route between Italy - Slovenia – Hungary to go ahead.

In 2018 Slovenian transmission system consisted of 946 km of pipelines with nominal pressure of more than 16 bars and 211 kilometres of pipelines with nominal pressure below 16 bars. The transmission system operator (TSO), company Plinovodi, also controlled 203 metering-regulation stations, 44 metering stations, seven reducing stations and two compression stations in Kidričevo and Ajdovščina. The transmission system is connected with neighbouring system in Austria at point Ceršak, with Italy at point Šempeter pri Gorici and Croatia at point Rogatec. At the border point with Italy bidirectional flow is possible, at the border point with Austria flow from Austria to Slovenia is possible and at the border point with Croatia from 2019 onward bidirectional flow is also possible. In short term future additional expansion of network is foreseen, connecting the southwest region to the natural gas network thus enabling use of natural gas for electricity and heat production in Ljubljana.

In the period between 2016 and 2018 daily technical utilization at exit points did not change. The largest daily capacity was at point Čeršak (import 76 GWh), followed by point Rogatec (export 43 GWh/import 7 GWh) and Šempeter (import 27 GWh/export 13 GWh). At all these points transmitted decreased amounts of gas in 2018 compared to previous years. The largest daily utilization of the transmission network in 2018 occurred on February 28th with 2.427.255 kWh/h not reaching contract or physical congestion.

Map 9.38 **Typology of Slovenian transmission system with relevant points**



Source: Plinovodi

Distribution network in 2018 consisted of 4.827 km of pipelines, increasing by 1,8 % compared to previous years. In the past there were talks that an LNG terminal would be constructed in Slovenia, but environmental concerns stopped the plans.

According to the currently valid ten-year gas transmission network development (TYTDP) plan for the 2019 - 2028, Slovenia is planning several new projects that will increase operational security and support expansion of the transmission network. Additionally, several projects for connecting new natural gas consumers or changing the operational characteristics of gas infrastructure, and projects for developing interconnection points are also envisaged. In this context, expansion of the transmission system includes system pipelines, energy loops, displacements of pipeline sections due to specific settlement modifications, and prevention of landslides.

A previously mentioned new project between Hungary and Slovenia is enabling the establishment of natural gas flows between Italy and Hungary via Slovenia, and thus the direct interconnection between these three gas markets. The project will also connect currently unconnected Slovenian and Hungarian transmission systems. Additionally, a group of projects in the Austrian corridor, via Slovenia, and towards Croatia, have a PCI status. This represents an upgrade of the capacity of existing transmission systems and the establishment of reverse flows between the systems in those three counties.

Also, it is worth mentioning the upgrade of the District heating system in the Slovenian capital Ljubljana, which includes replacement of two coal fired cogeneration units at the Thermal Power Plant Ljubljana (TE-TOL) with new natural gas fired combined heat and power plant, with total electrical power output of 142 MW. It is expected that this new unit will start with operation by the end of 2021 or at the beginning of 2022 and that it will enable a significant reduction of GHG emissions in Ljubljana.

The Government of **Montenegro** has already implemented the following activities to support the IAP and TAP projects. In 2016, the IAP Project Management Unit (PMU) was established, consisting of one representative of a national energy authority and one representative of a natural gas transmission system operator (TSO) from all four signatories to the Memorandum of Understanding and Cooperation on implementation of the IAP project - Albania, Bosnia and Herzegovina, Montenegro and Croatia.

Map 9.39 **Ionian - Adriatic Pipeline in Montenegro**

In 2017, the Government adopted the Master Plan for the development of the gas transport system (gasification) of Montenegro accompanied by the report on the strategic environmental impact assessment as well as the guidelines for the planning of priority investments in gas pipeline projects. The Master Plan explains the gasification of several large cities in Montenegro.

In **North Macedonia,** the gas imports are through Bulgaria's transit infrastructure, entering the country at Deve Bair. The national master pipeline, from Deve Bair, is extended further to Kriva Palanka, Kratovo, Kumanovo and Skopje. In North Macedonia there are 3 developed natural gas distribution networks in the towns of Strumica, Kumanovo and the Technology-Industrial Development Zone (DTIDZ) of Skopje. The distribution network in the city of Strumica is not connected with the transmission network and supply is ensured by truck transport of compressed natural gas (CNG) from Bulgaria. The natural gas distribution systems are constantly being developed and upgraded. However, distributed natural gas volume in their systems is minor, although there is noticeable ongoing growth. The largest portion of distributed gas is in the DTIDZ where there are several industrial consumers using natural gas in the production processes, as well as for heating. At this stage of gasification in the city of Skopje, there is practically no distribution network. Several existing customers, which are the largest consumers of natural gas in the country, are directly connected to the transmission network. However, there are plans and specific activities being planned aiming forwards the development of Skopje's distribution network development.

Map 9.40 **Existing (in bold) and planned natural gas infrastructure in North Macedonia**

Source: ERC, Draft Annual Report 2014

The Government has developed an ambitious national strategic plan for natural gas. The strategic plan is twofold and includes:

- Connection of North Macedonia to major international gas corridors (Greece,Serbia),
- Development of national transmission and distribution grids.

The planned development of the national transmission network for natural gas complies with the expected consumption needs in particular parts of the country. Some of the smaller towns in the country are envisaged to be supplied through so called "virtual pipelines" (dashed lines in Map 9.40). The expansion of the gas network is to be financed through the State Budget and EIB and EBRD credit lines. The state-owned JSC National Energy Resources (NER) is in charge of the above projects.

The interconnection with Greece, which is included in the Projects of Mutual Interest (PMI) list and is expected to be completed by 2022, is identified as the key project that will diversify supply. It will connect North Macedonia' s gas transmission system to Greece's transmission system. In addition, NER is involved in the Central and South East Gas Connectivity (CESEC) initiative. Under it, a Memorandum of Understanding (MoU) was signed in Dubrovnik in 2015 that includes projects for interconnectors between North Macedonia, Greece and Bulgaria. There is also potential for five other interconnections with Serbia, Albania, Kosovo, Bulgaria and Greece (link with Bitola).

9

The interconnector with Serbia is in the current PECI/PMI list too.

As reported by ERC, there are also several natural gas transmission pipelines under construction, with total length of 204 km (phase I), and due to be completed by the end of 2020. Those are:

- The Shtip – Negotino – Bitola pipeline (81% completed by the end of 2019) and
- The Skopje – Tetovo – Gostivar pipeline (57% completed by the end of 2019).

In phase II of the development of a national transmission network, NER plans to construct the following pipelines:

- Pipeline, section Gostivar – Kichevo (due in 2022),
- Pipeline, section Kichevo - Ohrid (due in 2025).

Furthermore, in order to provide for the further development and renewal of the country's natural gas transmission system, as well as development and expansion of the gas transmission pipeline grid, NER has also planned a number of actions, for the period from 2019 to 2023:

- Expansion of the city gas pipeline network in Skopje so as to connect several consumers,
- Completing the gas pipeline ring along with distribution lines for connecting interested consumers in the City of Skopje,
- Construction of a new connection to the transmission gas pipeline for the needs of CHPP TE-TO in order to increase its operating efficiency,
- Implementation of a SCADA system over the gas transmission network so as to enable measurements and detection of losses.

In **Israel,** the Israel Natural Gas Lined Network[69] includes 3 receiving LNG terminals (Ashod, Ashkelon and Hadera) and the transmission pipelines system. The main branches of the Israeli transmission network are shown in Table 9.59. As of end 2018, Israel Natural Gas Lines (INGL), had constructed about 750 km of transmission lines whilst the low-pressure distribution pipelines total 350 km.

[69] https://www.ingl.co.il/facts-and-information/?lang=en

Table 9.59 **Main branches of natural gas transmission system**

Trunkline	Total Length	Flow Routes	Date of Activation
Offshore	98 KM	Ashdod-Tel Aviv-Dor (inc. 8 Km pipeline to the LNG terminal – Jan. 2013)	5.2006
Central	94 KM	Ashdod-Sorek-kiryat Gat-Ashkelon, Sorek-Nesher	5.2007
Southern	135 KM	Kiryat Gat-Ramat Hovav-Dimona-Rotem-Sdom	11.2009
Northern	84 KM	Dor-Elyakim-Tel Kashish-Haifa, Tel kashish – Alon Tavor	7.2007 – Dor- Elyakim, 4.2011 – Elyakim-Tel Kashish-Haifa, Tel kashish – Alon Tavor
Dovrat – Ziporit	27 KM	Dovrat – Sede Ilan – Ziporit	1.2015
Ashdod – Sorek Looping	22 KM	Ashdod – Sorek	8.2015
Palmahim Pipeline	15 KM	Ashdod – Palmahim	2.2016
The southern Export Line to Jordan	16 KM	Sdom – Jordan	1.2017
The Eastern Pipeline	90 KM	Ramle – Elyakim	5.2017

Source: Israel Natural Gas Lines Ltd - INGL

Map 9.41 **Israel Natural Gas Transmission System**

Source: Israel Natural Gas Lines Ltd - INGL

In May 2018, the Ministry of Energy published a tender aiming to accelerate the deployment of the distribution network which includes three parts: long-term loans for building lines; long-term loans for increasing throughput; and long-term loans for building pressure reduction stations. The budget for the first round is 200 million NIS. Also, the Ministry published a tender for CNG fuelling stations estimated at 100 million NIS and another tender for connecting distant gas consumers valued at 50 million NIS.

Concerning interconnection projects between **Kosovo** and neighbouring countries, the ALKOGAP (Albania-Kosovo Gas Pipeline) is regarded as a favourable option for the connection of Kosovo through Albania with TAP respectively the IAP Projects. This project is included in the List of Projects of Energy Community Interest ('PECI' List). During 2018, a Pre-feasibility study for the ALKOGAP project was prepared, and financed through the WBIF platform – EBRD being lead IFI for this project. The main objective of this study was to undertake an initial assessment of the feasibility for the construction of the ALKOGAP pipeline, as the option of supply with natural gas from Caspian region through regional gas pipelines TAP / IAP, connecting in the first phase Albania and Kosovo, and potentially in the future to continue to other western Balkans countries. This study has included the following main components:

- A preliminary survey and determination of pipeline trench in Albania and Kosovo,
- Determination of the technical parameters of the pipeline and related stations and equipment, as well as pipeline hydraulic analysis and system configuration and optimization,
- Evaluation of the potential natural gas demand in Kosovo – namely: estimated consumption of the residential sector, services and industry, district heating including cogeneration of heat and electricity,
- Economic and financial analysis including estimation of the investment costs and O&M, and Cost benefit analysis,
- Review and assessment of the legal & regulatory and institutional framework, and elaboration of the organization of a natural gas market in Kosovo,
- Preliminary environmental and social impact assessment.

This pre-feasibility study has further recommended other project implementation phases, emphasizing preparation of a Gas Master Plan for Kosovo and preparation of a Feasibility Study for this project, which would provide detailed assessment of feasibility and sustainability of the ALKOGAP project, as a main precondition for developing natural gas markets in Kosovo and Albania.

Map 9.42 **Projects of regional gas infrastructure and options for connection of Kosovo**

Source: Energy Regulatory Office

The US MCC Programme ("Millennium Challenge Corporation") is carrying out a feasibility study exploring another entry to the gas market through North Macedonia. Part of the Energy Strategy 2017-2026, Kosovo also aims to establish a Gas Transport System Operator and Gas Distribution Operator and invest in natural gas infrastructure[70].

[70] MED – Energy Strategy of the Republic of Kosovo 2017-2026

References

(1) IEA, "Oil 2021 Analysis and forecast to 2026," [Online]. Available: https://iea.blob.core.windows.net/assets/1fa45234-bac5-4d89-a532-768960f99d07/Oil_2021-PDF.pdf.

(2) EUROSTAT, "Complete Energy Balances," [Online]. Available: https://ec.europa.eu/eurostat/web/main/data/database.

(3) IEA, "Key energy statistics 2018," [Online]. Available: https://www.iea.org/countries/greece.

(4) Republic of Kosovo, "Statement of Security of Supply for Kosovo (Electricity, Natural Gas and Oil)," [Online]. Available: http://ero-ks.org/2019/Publikimet/Deklarate_mbi_Sigurine_e_Furnizimit_ne_Kosove(energji_elektrike_gaz_natyror_nafte)ZRRE_31_07_2019_eng.pdf.

(5) Energy and Water Services Regulatory Commission of the Republic of North Macedonia for 2019, "Annual Report 2019," [Online]. Available: https://erc.org.mk/odluki/Annual%20Report%20ERC%202019%20-%20EN.pdf.

(6) Republic of Serbia, "Security of Supply Statement," [Online]. Available: https://www.energy-community.org/documents/parties/SoS.html.

(7) "Turkish Petroleum Market Report 2019," [Online]. Available: https://www.epdk.gov.tr/Detay/Icerik/1-2316/petroleumreports.

(8) Cambridge Econometrics, "Oil Dependency in the EU," 2020. [Online]. Available: https://www.transportenvironment.org/sites/te/files/publications/2020_CE_Oil_Dependency_in_EU_report.pdf.

(9) Fuels Europe, "Statistical Report 2020," [Online]. Available: https://www.fuelseurope.eu/wp-content/uploads/SR_FuelsEurope-_2020-2.pdf.

(10) European Commission, "Energy prices and const in Europe 2020," [Online]. Available: https://ec.europa.eu/energy/sites/ener/files/report_on_energy_prices_and_costs_in_europe_com_2020_951.pdf.

(11) Financial Times, "Commodities," [Online]. Available: https://markets.ft.com/data/commodities/tearsheet/summary?c=Brent+Crude+Oil.

(12) European Commission, "Weekly Oil Bulletin -Consumer prices of petroleum products," [Online]. Available: https://ec.europa.eu/energy/data-analysis/weekly-oil-bulletin_en.

(13) European Commission , "Weekly Oil Bulletin," 2021. [Online]. Available: https://ec.europa.eu/energy/observatory/reports/latest_prices_with_taxes.pdf.

(14) IENE, "SEE ENERGY BRIEF - Market Fundamentals and Prices," March-April 2021. [Online]. Available: https://www.iene.eu/market-fundamentals-and-prices-p5666.html.

(15) Globl Petrol Prices, "Diesel prices/ Gasoline prices," [Online]. Available: https://www.globalpetrolprices.com.

(16) Timothy C. Coburn, "Oil and Gas Infrastructure: A Technical Overview," [Online]. Available: www.oxfordhanbooks.com.

(17) IEA, "Energy policies of IEA countries- Greece 2017 Review," [Online]. Available: https://iea.blob.core.windows.net/assets/d34b4e20-d340-4563-822e-ae0cbe7e838b/EnergyPoliciesofIEACountriesGreeceReview2017.pdf.

(18) Conpet, "The National Transport System," [Online]. Available: https://www.conpet.ro/en/conpet-activity/the-national-transport-system/.

(19) IEA, "Energy Policies of IEA Countries: Hungary 2017 Review," [Online]. Available: https://www.iea.org/reports/energy-policies-of-iea-countries-hungary-2017-review.

(20) IEA, "Turkey 2021 Energy Policy Review," [Online]. Available: https://iea.blob.core.windows.net/assets/cc499a7b-b72a-466c-88de-d792a9daff44/Turkey_2021_Energy_Policy_Review.pdf.

(21) BOTAS, "Activities - Crude oil," [Online]. Available: https://www.botas.gov.tr/pages/crude-oil/359.

(22) European Commission, "Mid-term evaluation of Council Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products," [Online]. Available: https://ec.europa.eu/energy/sites/default/files/documents/mid-term_evaluation_of_council_directive_2009119ec.pdf.

(23) European Commission, "Ensuring security of energy supply in the EU: update of the emergency oil stocks Directive," [Online]. Available: https://ec.europa.eu/info/news/ensuring-security-energy-supply-eu-update-emergency-oil-stocks-directive-2018-oct-19_en.

(24) Energy Community Secretariat, "Implementation Report 2020," [Online]. Available: https://www.energy-community.org/implementation/IR2020.html.

(25) Republic of North Macedonia, "Strategy for Energy Develepment of the Republic of North Macedonia up to 2040," [Online]. Available: https://economy.gov.mk/Upload/Documents/Adopted%20Energy%20Development%20Strategy_EN.pdf.

(26) KEARNEY, "Time to develop an energy master plan for Southeast Europe," [Online]. Available: https://www.kearney.com/energy/article?/a/time-to-develop-an-energy-master-plan-for-southeast-europe.

(27) BP, "Statistical Review of World Energy 2020," [Online]. Available: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2020-full-report.pdf.

(28) CONCAWE - Environmental Science for European Refining, "Refinery Sites in Europe," [Online]. Available: https://www.concawe.eu/refineries-map/.

(29) HELPE, "Refining, Supply & Trading," [Online]. Available: https://www.helpe.gr/en/the-group/what-we-do/refining-supply-trading/.

(30) M. OIL, "The Refinery," [Online]. Available: https://www.moh.gr/en/company/the-refinery/.

(31) TUPRAS, "Refineries," [Online]. Available: https://www.tupras.com.tr/en/rafineries.

(32) SOCAR, "Facts about Socar," [Online]. Available: http://www.socar.com.tr/en/facts-about-socar/10-million-tons.

(33) HELPE, "Annual Report 2019," [Online]. Available: https://www.helpe.gr/userfiles/8ea1f0cb-9e62-48e4-b947-a27b00fb14bb/2020_06_19_EN_HELPE_Annual_Report_2019_Spreads.pdf.

(34) EA, "Renewables2019Analysis and forecast to 2024," [Online]. Available: https://iea.blob.core.windows.net/assets/a846e5cf-ca7d-4a1f-a81b-ba1499f2cc07/Renewables_2019.pdf.

References

(35) IEA, "Global Energy Review 2021," [Online]. Available: https://iea.blob.core.windows.net/assets/d0031107-401d-4a2f-a48b-9eed19457335/GlobalEnergyReview2021.pdf.

(36) European Commission, "Renewable Energy Progress Report," 2020. [Online]. Available: https://ec.europa.eu/energy/sites/ener/files/renewable_energy_progress_report_com_2020_952.pdf.

(37) Eurostat, "Energy Balances," [Online]. Available: https://ec.europa.eu/eurostat/web/energy/data/energy-balances.

(38) EurObserv'ER, "Biofuels Barometer 2020," [Online]. Available: https://www.eurobserv-er.org/category/all-biofuels-barometers/.

(39) Energy Community, "Modalities to foster use of renewable energy sources in the transport sector by the Energy Community Contracting Parties," 2020. [Online]. Available: https://energy-community.org/news/Energy-Community-News/2020/12/03.html.

(40) IRENA, "Renewables Readiness Assessment - The Republic of Albania," [Online]. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/March/IRENA_RRA_Albania_2021.pdf.

(41) ePURE, "Overview of biofuels policies and markets across the EU-27 and the UK," 2020. [Online]. Available: https://www.epure.org/wp-content/uploads/2021/01/201104-DEF-REP-Overview-of-biofuels-policies-and-markets-across-the-EU-Nov.-2020.pdf.

(42) ETIP, "Bioenergy Fact Sheet - Biofuels in Bulgaria," 2020. [Online]. Available: https://www.etipbioenergy.eu/images/ETIP_B_Fact%20sheet_Biofuels_Bulgaria_feb2020.pdf.

(43) ETIP, "Bioenergy Fact Sheet - Bioenergy in Croatia," 2020. [Online]. Available: https://www.etipbioenergy.eu/images/ETIP_B_Fact%20sheet_CROATIA_new_feb2020.pdf.

(44) South East European Industrial Market, "Renewable Energy Sector in Greece," [Online]. Available: https://www.see-industry.com/en/renewable-energy-sector-in-greece/2/1905/.

(45) ETIP, "Bioenergy Fact Sheet - Bioenergy in Romania," 2020. [Online]. Available: https://www.etipbioenergy.eu/images/ETIP_B_Fact%20sheet_ROMANIA_new_feb2020.pdf.

(46) ETIP, "Bioenergy Fact Sheet - Bioenergy in Serbia," 2020. [Online]. Available: https://www.etipbioenergy.eu/images/ETIP_B_Fact%20sheet_SERBIA_new_feb2020.pdf.

(47) ETIP, "Bioenergy Fact Sheet - Bioenergy in Slovenia," 2020. [Online]. Available: https://www.etipbioenergy.eu/images/ETIP_B_Fact_sheet_SLOVENIA_new_feb2020.pdf.

(48) ETIP, "Bioenergy fact sheet - Bioenergy in Hungary," 2020. [Online]. Available: https://www.etipbioenergy.eu/images/ETIP_B_Fact%20sheet_HUNGARY_new_feb2020.pdf.

(49) Argus Consulting Services, "Biofuels feasibility Study for Turkey," 2019. [Online]. Available: https://www.temizenerjifinansman.com/Uploads/Editor/files/4a.pdf.

(50) SEEPE, "Greek Oil Market," [Online]. Available: https://www.seepe.gr/%ce%b7-%ce%b5%ce%bb%ce%bb%ce%b7%ce%bd%ce%b9%ce%ba%ce%b7-%ce%b1%ce%b3%ce%bf%cf%81%ce%b1-%cf%80%ce%b5%cf%84%cf%81%ce%b5%ce%bb%ce%b1%ce%b9%ce%bf%ce%b5%ce%b9%ce%b4%cf%89%ce%bd/?lang=en.

(51) European Commission , "Consumer prices of petroleum products - Euro Super 95," [Online]. Available: http://ec.europa.eu/energy/maps/maps_weekly_oil_bulletin/latest_Oil_Prices_ES95.pdf.

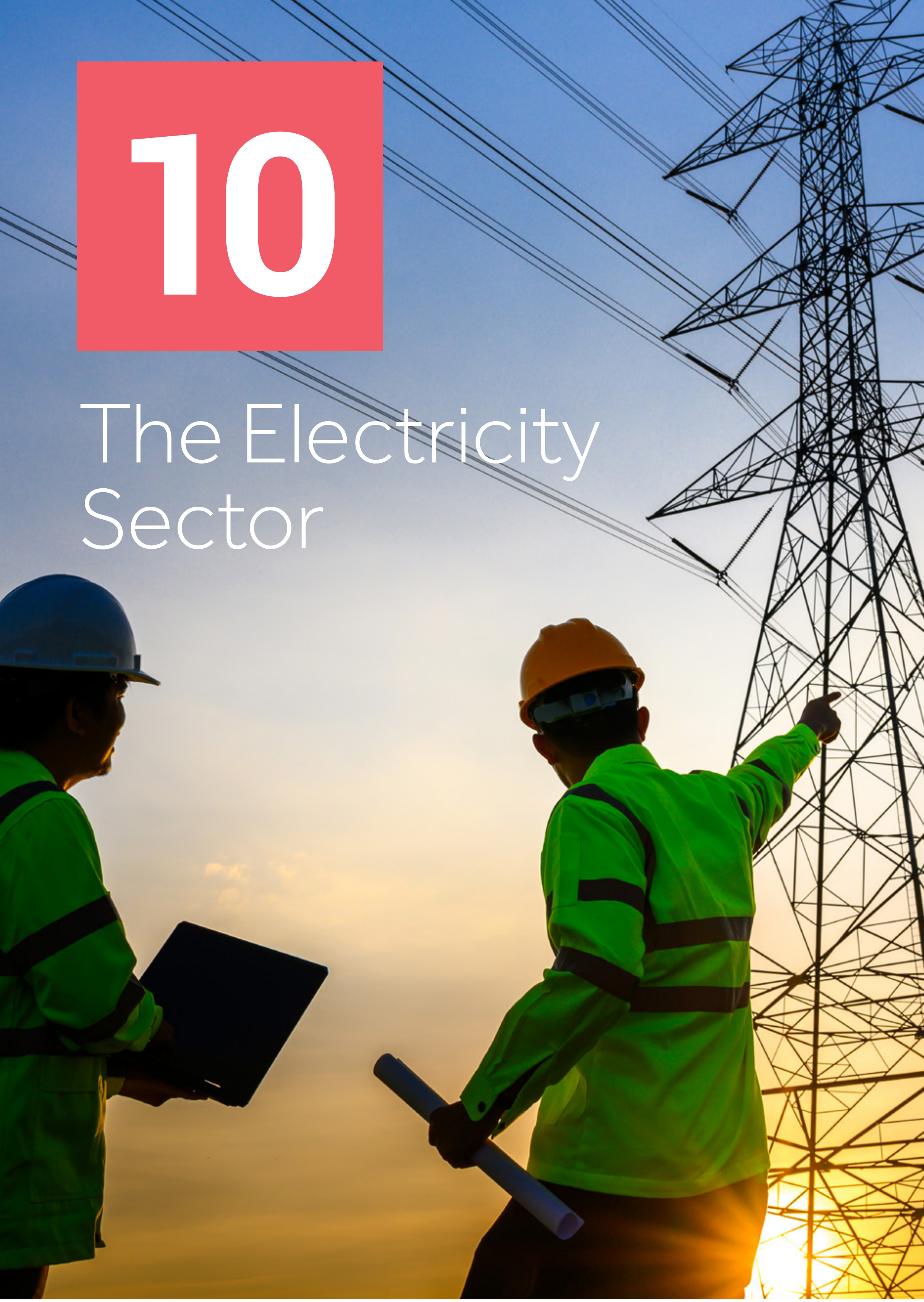
(52) Eurostat, "Complete Energy balances 15-4-2021," [Online]. Available: https://appsso.eurostat.ec.europa.eu/nui/submitViewTableAction.do.

(53) ONYX Advisory Benchmarks, "European Refinery Margin Benchmark," [Online]. Available: https://theonyxhub.com/benchmarks/european-refinery-margin-benchmark.

(54) Eurostat, "Energy from renewable sources," [Online]. Available: https://ec.europa.eu/eurostat/web/energy/data/shares.

(55) IRENA, "Bioenergy Data," [Online]. Available: https://www.irena.org/bioenergy.

9



10

The Electricity Sector

The Electricity Sector

10.1 Introduction

Today, the electricity sector in South East Europe faces significant challenges that are mainly associated with the ongoing energy transition and most recently demand uncertainties due economic activity limitations caused by the Covid-19 pandemic crisis, and the regulatory gaps emerging by such abrupt changes. The privatization of the energy sector as political choice in the region is still ongoing, while unbundling of electricity generation, supply, transmission and distribution has been progressing steadily. As power generation moves more and more to renewables and wholesale and retail electricity markets are liberalized more and more private entities emerge as active electricity market participants enhancing competition in the regional electricity markets. Moreover, in the last five years significant steps have been made towards electricity market integration at wholesale level, aiming to increase competition, liquidity and enabling a more efficient utilization of the generation resources across SE Europe.

Electricity consumption has been rising steadily across SE Europe during the last decade until 2019, when a mild winter brought electricity demand down across the region despite increasing economic development. Moreover, electricity consumption shrunk further in 2020-2021 as a result of the impeded economic activity due to the Covid-19 pandemic.

Even though energy transition is progressing steadily, there is a lack of diversification of power generation sources in the emerging markets of Albania, Serbia and Kosovo. The region has seen notable installed capacity changes over the last 5 years, with the share of installed capacity from coal and gas units falling as installed capacity in renewables rose to approximately 35 GW in the region, with most of which corresponding to wind farms and solar PV.

Wholesale electricity prices have slightly increased as a result of increased drought in S2 of 2018 and S1 of 2019 despite the slight decline in electricity demand. Retail electricity prices have been volatile throughout the region, remaining relatively stable for household consumers as part of this specific consumption remains partly regulated, most evidently in the Western Balkan region. Retail electricity prices for industrial consumers have been rising steadily, with slight slump in 2017 caused by lower prices offered on the wholesale level by regional producers.

10.2 Electricity Infrastructure in SE Europe

Power Generation

Currently, power systems in South East Europe are facing significant challenges on the path towards energy transition. These challenges stem from the overall goal for the decarbonization of regional power generation, as regional electricity markets are in the process of substituting coal/lignite-fired baseload generating units with newly developed natural gas and RES capacities. The main challenges therefore are the gradual transformation of the local coal-based economy and the implementation of the required grid enhancement projects aiming to facilitate the intermittent generation from newly deployed renewables.

Despite specific plans for phasing-out coal in the region, adequacy concerns emerging due to the decommissioning of older coal plants, make decarbonization of power generation a difficult choice. Therefore, there are coal and lignite projects currently under construction in the region, which include Ptolemaida V (615 MW) in Greece (expected to be converted a natural gas/hydrogen-run unit), TPP Kostolac B3 (320 MW[1]) and combined heat and power plant Pančevo of 190 MWe in Serbia and TPP Tuzla 7 (450 MW) in BiH, which are expected to come on stream in 2021, 2022, 2021, and 2023 respectively.

[1] Net capacity – 350 MW nominal capacity

Moreover, a number of other coal-fired power plants have been announced the most important of which are the TPP Kakanj 8 (300 MW) in Bosnia and Herzegovina and Kosova eRE in Kosovo, the implementation of which has been a controversial issue for the government of Kosovo, have been canceled once in the past, on March 2020 amidst environmental concerns and reaction to long term commitment to coal economy in the region[2].

At the same time, a most ambitious lignite phasing out program is being promoted by Greece, aiming at decommissioning 3.0 GW of existing lignite-fired net installed capacity by 2022 and a total of 3.8 GW, the entirety of Greece's current lignite-fired power plant fleet, by 2023[3]. Furthermore, the lignite phaseout will be achieved in Greece within 2025 according to recent announcements by PPC, with the conversion its new Ptolemaida V power station, which is expected to be commissioned in 2022, to a natural gas/hydrogen-run unit[4]. Romania is in the process of adjusting to more ambitious goals as it recently drafted its updated National Energy and Climate Plan (NECP) (31/01/2020), which anticipates the decommissioning of 1.26 GW of coal-fired baseload by the end of 2025. On the other hand, Bulgaria has chosen a more modest decarbonization path, which argues that indigenous energy sources like coal must be fully exploited for energy security purposes, setting lower decarbonization goals for the electricity sector with a much slower coal plant decommissioning rate and emphasis on efficiency increase of current plant capacity. According to Bulgaria's NECP the country plans for decommissioning the 0.9 GW of coal-fired power plant capacity by 2025 and a total of 1.8 GW by 2030, which accounts for approximately 58% of the country's current coal-fired power generating capacity[5].

On the other hand, the chosen decarbonization policies for the power sector in WB6 countries are not ambitious enough to fall in line with the European goals with the danger lurking of them breaching emission limits set by EU's Industrial Emissions Directive (IED).

Regarding new nuclear projects in the region scheduled before 2030, these include Reactors 5 and 6 at Paks NPP (2 x 1,200 MWe) in Hungary and the much-anticipated Unit 3 at NPP Cernavodă (720 MWe) in Romania, expected to be commissioned in 2025, 2026 and 2029 respectively. Moreover, Turkey's nuclear program is progressing. Towards the realization of Turkey's program, the country signed a Cooperation Agreement, under which Rosatom State Cooperation will construct the Akkuyu nuclear power plant. The plant will eventually comprise four VVER reactors with a combined capacity of 4800 MW[6], with units 1 and 2 expected to be commissioned in 2023 and 2024 respectively. Construction is underway on the first[7], second and third reactor[8]. Other nuclear power projects announced in Sinop and the Thrace region remain in the planning stage. More on the state of nuclear generation outlook and investment in SEE is presented in the box.

[2] https://prishtinainsight.com/contourglobal-kosova-e-re-will-not-proceed/
[3] https://ec.europa.eu/energy/sites/default/files/el_final_necp_main_en.pdf
[4] https://energypress.eu/greece-among-20-fastest-carbon-free-movers-by-2025/
[5] https://ec.europa.eu/energy/sites/default/files/documents/bg_final_necp_main_en.pdf
[6] Clercq, Geert De., "UPDATE 1-Rosatom Wins Licence to Build Second Nuclear Reactor in Turkey," Reuters, 6 September 2019, www.reuters.com
[7] https://world-nuclear-news.org/Articles/First-concrete-poured-for-Akkuyu-unit-3
[8] https://www.worldnuclearreport.org/IMG/pdf/wnisr2019-v2-hr.pdf

Nuclear Power in SE Europe

In SE Europe, there are five countries (i.e. Bulgaria, Hungary, Romania, Slovenia and Croatia) that currently operate nuclear power plants, while Turkey is expected to build no less than 3 nuclear power plants over the next 10-15 years. This means that nuclear energy has an important role to play in the SE European energy and electricity mix in the years ahead. A country-by-country analysis follows.

Bulgaria: In Bulgaria, nuclear power provided 15.44 TWh or 34.7% of the country's electricity in 2018, down from a maximum of 47.3% in 2002, based on data provided by the World Nuclear Industry Status Report 2019[9]. At the country's only nuclear power plant, Kozloduy, there are now just two reactors operating of the original four, whose average load factor reached an excellent 91.9%, the third highest in the world. The two VVER1000 reactors are undergoing a relicensing program to extend their operating lifetimes for up to 60 years. There have been ongoing attempts since the mid-1980s to build another nuclear power plant at Belene in Northern Bulgaria, but so far, all of them have failed. Belene was to consist of two VVER1000/AES-92 reactors, a design that is no longer marketed by Rosatom. However, the nuclear project at Belene is heavily advocated by the Bulgarian authorities, who are in the process of seeking a single strategic investor for the project through tendering procedures.

Hungary: Hungary has one operating nuclear power plant at Paks, where four VVER 440-213 reactors provided 14.9 TWh or 50.6% of the country's electricity in 2018. The nuclear share in the national power mix is down from 53.6% in 2014. The reactors started operation in 1982-1987 and have been the subject of engineering works to enable their operation for up to 50 years (compared to their initial 30-year license).

The first unit received permission to operate for another 20 years in 2012, the second unit in 2014, the third in 2016 and the fourth in December 2017, enabling operation until the mid-2030s. Paks NPP's expansion consists of Paks II, which will contain two VVER -1200 reactors (2x 1200 MWe) and commenced construction in 2019 by Rosatom. Reactors 5 and 6 of the Paks complex are expected to be commissioned in 2025 and 2026 respectively but reports suggest that operation will not start before 2027-2028.

Romania: Romania has one nuclear power plant at Cernavoda, where two Canadian-designed CANDU reactors are in operation. In 2018, in a similar manner to 2016 and 2017, they provided 10.5 TWh or 17.2% of the country's electricity, compared to 20.6% in 2009. The two reactors were constructed between 1982 and 1987. Unit 1 was commissioned in 1996, and Unit 2 went on stream in 2007, respectively 14 and 24 years after construction started. The Cernavoda reactors are amongst the top lifetime performing reactors, with Unit 2, the highest and Unit 1 in third place globally. In 2018, their average load factor was 92.4%, one percentage point lower than in the previous year. Nuclearelectrica, the plants owner and operator has elaborated plans to refurbish the two active reactors, a process which is scheduled for 2026-2027[10]. Moreover, Nuclearelectrica aims in starting construction of Cernavoda NPP's unit 3 on 2024 an investment which has not yet been realized.

[9] https://www.worldnuclearreport.org/IMG/pdf/wnisr2019-v2-hr.pdf
[10] https://seenews.com/news/canadas-laurentis-wins-contract-to-support-refurbishment-at-romanias-cernavoda-npp-732023

Slovenia: Slovenia jointly owns the Krško nuclear power plant with Croatia, a 696 MW Westinghouse Pressurized Water Reactor (PWR). In 2018, it provided 5.5 TWh or 35.9% of Slovenia's electricity, down from 6.0 TWh or 39.1% in 2017, and below the maximum of 42.4% in 2005. The load factor of Krško was the 2nd highest in the world in 2017, averaged 90.7% in 2018, down from 98.7% in 2017. The reactor started operation in 1981 with an initial operational life of 40 years. In July 2015, an Inter-State Commission agreed to extend the plant's operational life to 60 years, so that it would continue until 2043, as well as to construct a dry storage facility for the spent fuel.

Turkey: In Turkey, three separate projects have been under consideration over the past decades with three different reactor designs and three different financing schemes. Despite this, in early 2018, construction formally began in only one of these projects.

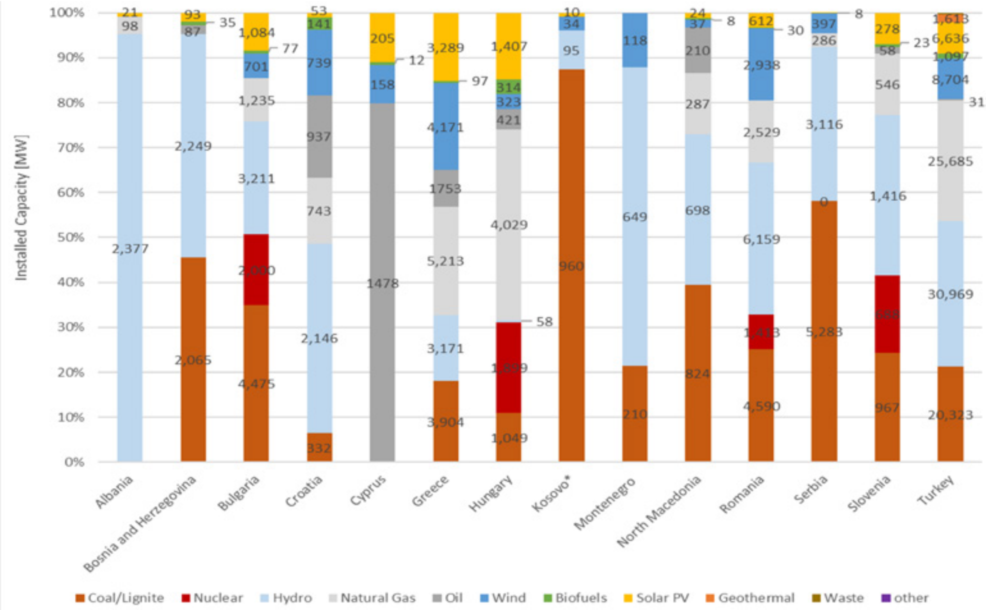
Akkuyu: The nuclear power plant is locked at Akkuyu, which is in the province of Mersin on Turkey's Mediterranean coast. Construction started in April 2018, and is implemented by Rosatom under the Build-Own-Operate (BOO) market model. Although Rosatom initially was supposed to completely own the project, according to the original agreement, at least 51% of shares in the finished project should belong to Russian companies and up to 49% of shares can be available for sale to outside investors. The power plant will include four VVER-1200 reactors (Generation III+) (4x 1200 MWe) and is expected to be in operation in 2023 according to latest announcements. The project has suffered some delays in 2019 due to construction deficiencies, as cracks were discovered in its foundations. The project has been widely discussed and criticized due to concerns for nuclear safety, due to its location in a region which is prone to severe earthquakes.

Sinop: Sinop is on Turkey's northern coast and was planned to host a 4.4 GW power plant consisting of four units of the ATMEA reactor-design, a project that was approved by the Turkish government in 2015. The project still remains in the planning phase as the Mitsubishi Heavy Industries, the main investor in the project had withdrawn in December of 2018.

İğneada: In October 2015, the Turkish government suggested it was aiming to build a third nuclear power plant, at the İğneada site. The most likely constructors would be Westinghouse and the Chinese State Nuclear Power Technology Corporation (SNPTC), however the recent financial collapse of Westinghouse makes its current involvement in the project unlikely.

Greece is the only country in the region that has consciously chosen natural gas as a transition fuel, with two large gas projects in the pipeline, one by Mytilineos S.A. (826 MW) already under construction and one by Elpedison (828 MW), expected to be connected to the grid in 2022 and 2023 respectively. Newly built gas power generating units in SEE region include the Panchevo CCGT (200 MW) in Serbia and TEC Vlora CCGT (98 MW) in Albania, and are expected online as early as 2021 and 2024 respectively.

Figure 10.1 **Installed Power Generating Capacity per Country and Production type in SE Europe (MW) (2020)**



Source: IENE from data derived from ENTSO-e, ERE, CERA, IPTO, HEDNO, Transelectrica, MAVIR, TEIAS, ERC, ESO, Energy Agency of Slovenia.

With regard to the deployment of **renewables**, significant steps have been made by Greece with 727 MW of new windpower being deployed during 2019. Albania has also made steps for the installation of new Solar PV, with the deployment of the first phase of the Akerni Vlora Solar PV farm (50 MW) and various smaller projects (15 MW), which were connected during 2019. Montenegro has also made progress with the connection of WPP Mozura (46 MW) and commencing the construction of a large Solar PV farm at Briska Gora (250 MW) in 2020. Moreover, Serbia is aiming at increasing RES penetration with the commissioning of Wind Farm Kostolac (66 MW) and HPP Potpec G4 (13 MW) in 2020. On the other hand, deployment of Solar PV and windfarms was rather stalled in Bulgaria, North Macedonia and BiH during 2019.

Concerning the deployment of **hydropower** plants, important projects are currently being developed in Albania with planned total installed capacity of 558 MW, to be implemented in the period 2020 - 2023.

Furthermore, future hydropower projects in the SEE region might derive from Bosnia and Herzegovina's high untapped potential. More specifically BiH as identified by the "Framework of Energy Strategy for Bosnia and Herzegovina until 2035[11]" has untapped hydropower potential which could yield up to 50 projects with a total cumulative generating capacity of 2.32 GWh. In Romania, the country's "National Energy and Climate Plan" (NECP) envisages hydro energy as a sustainable alternative for the development of the energy sector.

According to this strategy, by 2030 Romania intends to add new hydropower production capacity, with a potential of 1088 MW of new hydropower units, which is expected to help Romania achieve a 3.1% increase of domestic hydropower yield by 2030 in comparison to the levels of 2020, as mandated in the plan. This increase will result to a total multiannually expressed electricity production from hydro of approximately 17 TWh/year or 1460.3 ktoe from 16.46 TWh/year in 2020[12].

[11] http://www.mvteo.gov.ba/data/Home/Dokumenti/Energetika/Framework_Energy_Strategy_of_Bosnia_and_Herzegovina_until_2035ENG_FINAL....pdf

[12] https://ec.europa.eu/energy/sites/default/files/documents/ro_final_necp_main_en.pdf

The much-discussed Turnu Magurele-Nicopole (400 MW) hydropower plant on the Danube river located in Romania has yet to see a concrete implementation proposal but has been heavily advocated by Romanian state-controlled hydropower company Hidroelectrica[13]. Turkey is the major investor in hydropower projects in the region with more than 1,000 MW of hydroelectric dams commissioned in the period of 2018 – 2019[14].

Power Transmission

As the Ten-Year-Network-Development-Plan (TYNDP) for Electricity is the most comprehensive and up-to date planning reference for the pan-European transmission electricity network, the data presented below is derived from the TYNDP-2018 as well as from relevant studies[15].

ENTSO-E is structured into six regional groups for grid planning and other system development tasks. One of these six regional groups is the Continental South East (CSE) region, which covers the Balkans area and Italy. The Regional Group CSE comprises the TSOs of Albania (AL), Bosnia-Herzegovina (BA), Bulgaria (BG), Croatia (HR), Cyprus (CY), Greece (GR), Hungary (HU), Italy (IT), North Macedonia (MK), Montenegro (ME), Romania (RO), Serbia (RS) and Slovenia (SI). The data presented below refer to Albania (AL), Bosnia-Herzegovina (BA), Bulgaria (BG), Greece (GR), North Macedonia (MK), Montenegro (ME), Romania (RO), Serbia (RS) and Kosovo (KO).

As shown on Map 10.1, based on the latest data by ENTSO-E[16], there are 43 interconnections between the aforementioned countries and its two neighbouring countries (i.e. Italy and Turkey), affecting 16 borders.

Map 10.1 **Interconnections between EU member countries, Balkan countries, Italy & Turkey**

Source: ENTSO-E

The physical transmission capacity, the physical electricity flows and the scheduled commercial flows vary greatly depending on the border. The electricity lines are also characterised by different voltage levels and capacity. Several interconnectors within the Western Balkan region are actively used for commercial purposes, both for import and export; many of them were constructed as internal network of former Yugoslavia. The lines in SEE are of particular relevance given the geographical features of the region; they offer in total approximately 21 GW of cross-border interconnection capacity, taking into account the net transfer capacity of the power lines as it is determined by Entso-e and the regional TSOs in 2020.

The interconnectors ensure security of supply and electricity trade in both directions, with exports being considerably predominant from Bulgaria and Serbia within the CSE region. The group of countries consisting of Greece, North Macedonia and Albania are net importers, with the result that one of the main power flow directions in the Balkan region is from North to South. Specifically, interconnectors from North Macedonia to Bulgaria and Greece are used for trade and security of supply purposes with exports considerably prevailing from

[13] https://www.romania-insider.com/hidroelectrica-hydropower-plant-danube
[14] https://www.aa.com.tr/en/energy/hydro/global-hydropower-capacity-grows-by-197-in-2018/25469
[15] https://docstore.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/rgip_CSE_Full.pdf
[16] https://www.entsoe.eu/data/map/

Bulgaria and imports to Greece. Also, the interconnector between Albania and Greece is regularly used for electricity trades and offers imports of cheaper electricity to both countries. Turkey is synchronously connected with continental Europe through one electricity line to Greece and two lines to Bulgaria. Both EU member states trade electricity with Turkey with imports contributing to the security of supply of both countries. In Table 10.1, the Net Transfer Capacity (NTC) in the borders of SEE countries in 2020 and in the future (2040), as projected by Entso-e are presented.

Table 10.1 **NTC Capacity in the borders of SEE countries in 2020 future scenarios considered by Entso-e**[17]

	NTC 2020		**CBA Capacities**		**Scenario Capacities**					
			NTC 2027 (reference grid)		NTC ST2040		NTC DG2040		NTC GCA2040	
Border	=>	<=	=>	<=	=>	<=	=>	<=	=>	<=
AL-GR	250	250	250	250	350	350	350	350	350	350
AL-ME	350	350	400	400	900	900	400	400	400	400
AL-MK	500	500	500	500	500	500	500	500	1000	1000
AL-RS	650	500	500	500	1260	830	760	330	1760	1330
BA-HR	750	700	1250	1250	1844	1812	1844	1812	2344	2312
BA-ME	500	400	800	750	500	400	500	400	500	400
BA-RS	600	600	1100	1200	1100	1200	1100	1200	1100	1200
BG-GR	600	400	1350	800	1728	1032	3228	2532	3228	2532
BG-MK	400	100	500	500	400	100	400	100	900	600
BG-RO	300	300	1100	1500	1400	1500	1400	1500	1400	1500
BG-RS	500	200	350	200	1600	1350	2100	1850	2100	1850
BG-TR	700	300	1200	500	2400	2000	2400	2000	2400	2000
CY-GR	0	0	0	0	2000	2000	2000	2000	2000	2000
GR-ITs	500	500	500	500	500	500	500	500	500	500
GR-MK	1100	850	1200	1200	1600	1350	2100	1850	2100	1850
GR-TR	660	580	660	580	2200	2100	2200	2100	2200	2100
HR-HU	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
HR-RS	600	600	600	600	2100	2100	2100	2100	2100	2100
HR-SI	1500	1500	2000	2000	2500	2500	3000	3000	3500	3500
HU-RO	1000	1100	1300	1400	1300	1400	1800	1900	2800	2900
HU-RS	600	600	600	600	1100	1100	2100	2100	2100	2100
HU-SI	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
HU-SK	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
ITcs-ME	600	600	1200	1200	1200	1200	1200	1200	1200	1200
ITn-SI	680	730	1660	1895	1660	1895	1660	1895	1660	1895
ME-RS	500	600	700	700	1000	1100	1000	1100	1500	1600
MK-RS	650	800	750	750	650	800	1650	1800	1650	1800
RO-RS	1000	800	1300	1300	1450	1050	1950	1550	2950	2550

[17] https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP2018/System_Need%20Report.pdf

New regional grid interconnections are planned to facilitate the excess generation of variable renewables as flexible and intermittent generation becomes a norm in SEE. Most notable is the recently completed Italy-Montenegro interconnection project, deployed in November 2019, which links via a HVDC subsea cable Villanova (Italy) to Lastva (Montenegro). Ongoing projects of major importance for the interconnectivity in SEE are:

(a) the Black Sea Corridor project (Romania – Bulgaria): The project consists of one 400kV double circuit OHL Cernavoda-Stalpu with in/out connection of one circuit in Gura Ialomitei, one 400 kV double circuit OHL Smardan-Gutinas in Romania and also the new 400 kV OHL Dobrujda-Burgas in Bulgaria. This project allows transfer of electricity from the Western coast of the Black Sea towards consumption and storage centers in Central Europe and South-Eastern Europe. The project addresses the following system[18] needs:
- Increase of transfer capacity in the North-South direction at the boundary between Romania and Bulgaria, which will support the large-scale integration of new RES in the area of Black Sea coast in both countries and especially Romania.
- Implementation of this PCI will bring the interconnection level of Romania much closer to the achievement of the 10% electricity interconnection target.

(b) the CSE4 400kV power link between Bulgaria and Greece: The project concerns the construction of a new AC 400kV interconnection between Bulgaria and Greece and new AC 400kV overhead lines at the south part of Bulgaria. This project will increase cross border transfer capacity between Bulgaria and Greece and is expected to be commissioned in 2023. This project contributes to the reduction of electricity prices for consumers in the south part of the region by providing access to cheaper sources of generation in the north-east part. Potentially it will be increasing RES integration in north part of Greece

(c) the Mid Continental East corridor (Serbia - Romania): The project consists of one double circuit 400 kV interconnection line between Serbia and Romania and reinforcement of the network along the western border in Romania: one new simple circuit 400 kV line from Portile de Fier to Resita and upgrade from 220 kV double circuit to 400 kV double circuit of the axis between Resita and Arad, including upgrade to 400 kV of three substations along this path: Resita, Timisoara, Sacalaz. The project aims at enhancing the transmission capacity along the East-West corridor in the South-Eastern and Central Europe. The interconnection level of Romania would increase from the current level of 7% to above 9%, getting therefore closer to the target of 10% through the implementation of the interconnection with Serbia by 2018. This project aims to increase the transfer capacity across the RO-RS-HU boundaries. The project further enhances the transmission capacity along the East-West corridor in the South-Eastern and Central Europe. The project supports the large-scale integration of new RES in the region of South-West Romania and North-East Serbia.

(d) the Transbalkan Corridor (Serbia – Montenegro – Italy): The aim of this project aim is to increase the transmission capacity within Serbia and facilitate the exchange of energy between north-east and the south-west part of Europe. Specifically, the project's investments will form a new HV AC and DC corridor from Serbia, through Montenegro to Italy, enhancing energy exchange and further market integration in the SEE region. Furthermore, this project will enable better connection of Eastern Balkans and Italy through 400 kV AC lines and a 500 kV DC cable. This connection will enable reduction of price differentials between Balkan countries and Italy. Energy flows from the 220 kV network will redistribute on 400 kV network between RS, BA and ME, after project realization.

(e) The new interconnection line between

[18] https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP%202016/projects/P0138.pdf

Serbia and Croatia: Construction of the new 400 kV interconnection line Sombor (RS) - Ernestinovo (HR) This project will help redistribute flows, generated from new RES projects in the north part of RS and east part of HR.

(f) The new 400 kV interconnection line between Hungary and Romania: This project helps Romania to achieve an interconnection level of 15% by 2030, and at the same time it contributes to the reduction of price differentials (by adding capacity) across EU. In Romania, the following internal investments associated to this project are necessary: -new 400/220 kV transformer in substation Rosiori -reconductoring[19] 220 kV OH line Urechesti-Tg. Jiu-Paroseni- Baru Mare-Hasdat -new 400/220 kV transformer in substation Resita

(g) North CSE Corridor: This project consists of three investment phases: (i) SS 400/110 Belgrade West, (ii) OHL 400 kV SS Belgrade West WPP Cibuk and (iii) doubling existing OHL 400 kV Portile de Fier (RO) - Resica (RS). The new interconnection between Romania and Serbia will enhance cross border energy flows in east-west direction. Moreover, relatively low cost energy from RES in South-West Romania could be exported to the west part of the Balkan area which will reduce price differences between the regions. This project will also enhance the absorption of energy from new wind power plants in North-East part of Serbia

(h) Central Balkan Corridor: This corridor will enable transmission of energy from east to west on the border between Bulgaria and Serbia. It consists of several phases from Sofia West on the east to Bajina Basta. In this way this corridor will be directly connected with the Transbalkan corridor. This project will enhance flows in the east-west direction due to the new interconnection between Bulgaria and Serbia. Moreover, relatively low cost production from RES in Bulgaria will reduce price differentials between eastern and western part of Balkan.

(i) CSE1 New: The project will help in strengthening the Croatian transmission grid along its main north-south axis (in parallel with eastern Adriatic coast) allowing for additional long-distance power transfers (including cross border) from existing and new planned power plants (RES/wind/ and conventional/hydro and thermal/) in Croatia (coastal parts) and BiH to major consumption areas in Italy (through Slovenia) and north Croatia. The increased transfer capacity will support market integration (particularly between Croatia and Bosnia-Herzegovina) by improving security of supply (also for emergency situations), achieving higher diversity of supply and generation sources and routes, increasing resilience and flexibility of the transmission network. The main aims of CSE1 New project are:
- To provide additional transmission capacity in order to facilitate the high RES penetration in the area. The project will create an alternative line for power transfer.
- To create an alternative line for power transfer in order to avoid risk of violation of N-1 security criterion in the future due to increase of power generation[20].

(j) South Balkan Corridor: This project consists of three investments[21]: one 400 kV overhead line (OHL) Bitola(MK)- Elbasan(AL), and two 400 kV Substations (SS) Ohrid and Kumanovo, in North Macedonia.The interconnection contributes to increasing the transmission capacity in the East-West direction. The mentioned two SS-s will increase the security of supply in the SouthWest part of North Macedonia. Construction of 400 kV OHTL interconnection from SS Bitola 2 to North Macedonian /Albanian border and SS

[19] To replace the cable or wire on an electric circuit, typically a high-voltage transmission line, usually to afford a greater electric-current-carrying capability.

[20] The N-1 criterion states that a system that is able to withstand at all times an unexpected failure or outage of a single system component, has an acceptable reliability level. This implies that some simultaneous failures could lead to local or widespread electricity interruptions, therefore, N-1 criterion threshold indicates that TSOs after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits (Article 3(2)(14) of the Network Code on System Operation).

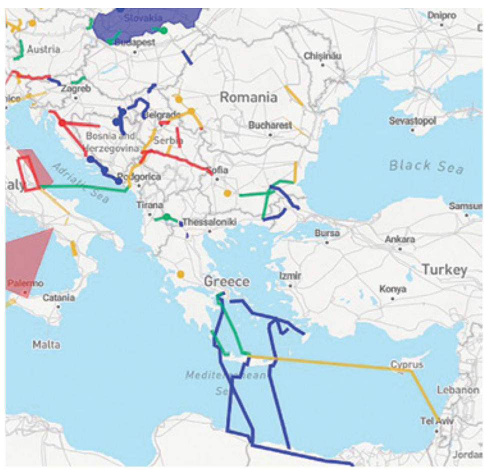
[21] https://tyndp.entsoe.eu/tyndp2018/projects/projects/350

400/110 kV Ohrid 400 kV interconnection transmission line Bitola (North Macedonia) - Elbasan (Albania) is the last part of the implementation of the Corridor 8 in the context of creating a corridor of East-West power transmission between Bulgaria, North Macedonia, Albania and Italy. The project will contribute to higher RES integration as well as to NTC values increase in both directions in 500 MW, facilitating the transit form East Balkans to Italy

(k) Refurbishment of the 400kV Meliti(GR)-Bitola(MK) interconnector: The project aims at the reconductoring of the existing 400kV interconnector between Meliti(GR) and Bitola(MK), in order to increase transfer capacity of the interconnector. The project will achieve the resolution of the cross-border bottleneck that appears in GCA 2040 and DG 2040 scenarios in the GR-MK border with the under-consideration refurbishment of OHL 400kV Meliti (GR) – Bitola (MK). Moreover, the project is expected to improve flexibility issues due to extremely high residual ramp loads identified in the IoSN[22] studies for Greece. Also, it may resolve the cross-border bottleneck that appears in GCA 2040 and DG 2040 scenarios due to the high increase of RES capacity in Greece and the E>W flows in the region. According to the IoSN market results for all 2040 scenarios, the under-consideration refurbishment of OHL 400kV Meliti (GR) – Bitola (MK) may result in approximately 20€/MWh reduction in average hourly differences of marginal prices of the GR-MK border [23].

(l) Furthermore, IPTO, Greece's TSO, has commenced phase 3 of the interconnection of the Cyclades islands with the mainland grid in the 4th quarter of 2020 and is progressing with the interconnection of Crete with the mainland system, with the first phase including AC interconnector Peloponnese – Crete been completed on December of 2020[24] and is expected to be fully operational by the second semester of 2021[25]. The second phase of Crete's interconnection, includes a DC cable interconnector between Attica and Crete which is scheduled to come online in 2023. These interconnection projects are of major importance for Greece's NECP targets, as they will enable the decarbonization of the island systems, which are currently dependent on oil for more than 80% of their electricity supply. A tandem project to the interconnection of Crete is the Euroasia interconnector which aims at connecting Crete (and mainland Greece) to Cyprus and Israel, currently undergoing permitting stage (see Map 10.2). The above projects are either under consideration (blue), in planning phase (red), in permitting phase (yellow) or under construction (green) as shown in Map 10.2.

Map 10.2 **Cross-border Interconnection projects under development in SEE**



Source: Entso-e

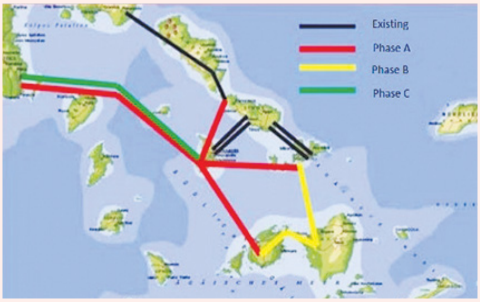
[22] Identification of System's Needs
[23] https://tyndp.entsoe.eu/tyndp2018/projects/projects/376
[24] https://balkangreenenergynews.com/greece-tests-peloponnese-crete-link-worlds-longest-undersea-ac-cable/
[25] https://renewablesnow.com/news/crete-peloponnese-subsea-interconnector-completed-in-greece-736968/

The Interconnection of Cyclades Islands With the National Interconnected Transmission System of Greece

The electricity interconnection of Cyclades Islands, undertaken by the Independent Electricity Transmission Operator of Greece (IPTO), is a technically demanding project. When fully completed, it will ensure the reliable, economic and sufficient supply of electricity to most of the Cyclades islands over the next 30-40 years. This unique and highly complex project comprises of three phases.

1. Phase A covers the connection of Syros Island to Lavrion (mainland), as well as with the islands of Paros, Mykonos and Tinos.
2. Phase B covers the connection between the islands of Paros and Naxos and the connection of Naxos to the island of Mykonos.
3. Phase C covers a second interconnection between Lavrion (mainland) and the island of Syros.

Map 10.3 **Electricity Interconnection of Cyclades Islands**



Source: IPTO

Phase A: Paros-Syros-Mykonos

This is a Project of Common Interest (PCI) and involves a Submarine Transmission Cable and a Substation. The implementation of Phase A was completed in the early months of 2018. Up to that time, the Autonomous Power Stations (APS) on these islands were sufficient for safely meeting current and anticipated demand.

The first connection involves the island of Syros to Lavrio, in mainland Greece, as well as the islands of Paros, Mykonos and Tinos.

Following its completion, the APS were put in cold reserve mode and the electricity supply of the islands is provided entirely from the Hellenic Electricity Transmission System (HETS). Phase A of the interconnection of the Cyclades also includes a number of separate subprojects, including the construction of GIS substations in Syros, Paros and Mykonos.

In terms of benefits, Phase A of the Cyclades interconnection ensures the transmission of power from HETS to Syros up to a minimum of 170 MW even in the case of failure of the Lavrio-Syros cable. This volume of transmitted power generally suffices to meet demand on the islands. The project was completed in 2018 at a cost of €250 million.

Phase B: Andros, Syros, Paros, Tinos and Naxos

This part of the project involves the interconnection of the islands of Syros, Mykonos, Paros and Naxos to the HETS, and the reinforcement of the Andros – Tinos interconnection. The main focus of the project is the minimisation of environmental repercussions on the islands. To this end, the new substations have been placed close to the coast, to avoid construction of overhead Transmission Lines with surrounding transmission cables placed underground.

Phase B of the Cyclades Interconnection was completed in September 2020 with the interconnection of Naxos to the High Voltage System. It consisted of the following projects:

- Paros - Naxos connection with a submarine tripolar cable with a length of 7.6 km.
- Naxos - Mykonos connection with a submarine tripolar cable with a length of 40 km.
- New Substation on Naxos, and the necessary interconnection projects at the substations of Paros and Mykonos.

In parallel to Phase B, the upgrade of the existing cable connection of Andros - Livadi (South Evia), with a length of 14.5 km, and Andros – Tinos (4km), with new submarine cables in replacement of the existing oil cables were undertaken. The project was completed in early 2020.

The total value of Phase B amounted to €95,5 million and of the project was partly funded by the European Development Fund (EDF).

Phase C: Reinforcement of the Syros interconnection

Phase C of the project involves the strengthening of the interconnection by installing a second submarine cable between Lavrio and Syros, as well as the required connection works at Lavrio and Syros. The goal of Phase C is to assure the necessary reliability under all operational conditions, depending on the evolution of demand on the interconnected islands.Completion of Phase C ensures full reliability in the supply of the whole Cyclades island group for the planned project operation time frame and in N-1 conditions for the Lavrio-Syros line. Phase C is considered as a Project of Common Interest and its total value amounted to €118 million.

Benefits

By closing the loop between Paros, Naxos and Mykonos, the project significantly strengthened the reliability of electricity supply to these islands. After completion of Phase B, the islands have also secured double supply, which means that incidents such as cable disconnections (N-1), which would require the start up the Autonomous Power Stations on an auxiliary basis are limited. Also, by reinforcing the capacity of the existing interconnection to Evia (amounting to approx. 170 MW) the interconnection of Cyclades with HETS is ensured in the case of loss of the Lavrio - Syros cable, meaning that the specific transmission capacity is estimated to be sufficient for meeting the demand on the islands for the stipulated time frame of the project's operation.

Furthermore, this major island interconnection project ensures reliable electricity supply for the whole of the Cyclades island group, which until recently had been hindered by limited supply capability and environmental concerns arising from the operation of the Autonomous Power Stations (APS) installed and operating on all islands. Thanks to this interconnection project, power supply production costs are already reduced and energy demand is moderated. Moreover, there is visible environmental improvement by allowing the scaling down and eventual removal of the existing power stations which operate on heavy fuel oil or light fuel oil (diesel), while further environmental disturbance is minimized by avoiding the construction of overhead transmission lines.

Finally, this project is providing a much-needed infrastructure for enhancing the utilization of the island's significant renewable energy potential. Hence, the project is of great strategic importance to Greece, with much added value at the same time.

Ariadne Interconnection
A Milestone Project for Greece

Ariadne Interconnection SA is a company fully owned by Greek electricity grid operator IPTO SA, which has undertaken the implementation of the 1000 MW HVDC Attica-Crete interconnection project in Greece. The Ariadne interconnection will connect the Attica region in mainland Greece to the island of Crete, which is currently totally dependent on oil-fired power stations. It will facilitate the exchange of electricity and help the island develop its substantial renewable energy potential.

The electrical interconnection of Crete with the mainland is pivotal in achieving Crete's goal to overhaul its electricity system in the next few years. Connecting the largest Greek island with the national electricity transmission network is a decisive step in this direction, as well as in the transition of the country to a low carbon footprint economy.

The project is being implemented in two phases. The first phase involves Crete's interconnection with the Peloponnese, a project with a total budget of €350 million, which will be fully operational by the end of 2021. The second phase concerns the interconnection between Attica, the mainland, and Crete, has a budget in excess of €650 million and is expected to be completed before the end of 2023. Funding for this €1.0 billion major infrastructure project comes from 3 different sources: bank lending, equity and EU funding.

Project Description

The project infrastructure consists of five distinct parts:

(a) Peloponnese to Crete interconnection

The interconnection of Crete with the Peloponnese constitutes the first phase of the interconnection of Crete with the Hellenic Electricity Transmission System (HETS). The project consists of the construction of 150 kV AC 2x200 MVA interconnection between the island of Crete and peninsula Peloponnese. The project includes two new submarine cables with the length of 135 km each, upgrades of the existing and construction of new transmission lines, underground cables and substations in the Peloponnese and Crete, static synchronous compensator on Crete. The landing points of the submarine cables are in the Kissamos Bay (Crete) and the Malea peninsula (Peloponnese).

(b) Underground/submarine DC line from Attica to Crete

- The main installation involves two (2) submarine HVDC cables, approximately 328km long each, with a rated power of 1000 MW in bipolar operation, from the Megara beach (Attica) to the Korakia beach (Crete).
- An underground/submarine MVDC cable from the Attica converter station to the Megara beach with an underground cable and from the Megara beach to the small island of Stachtoroi electrode station with a submarine cable.

Also, a number of underground HVDC cables are foreseen in both Attica and Crete, which will connect the Converter Stations with the DC interconnector.

(c) AC/DC converter stations

Two converter stations are foreseen, one in Attica and the other one in Crete.

- The Attica station: It involves a new AC/DC converter station with a rated power of 1000MW (2 x 500 MW), voltage up to 500kV, operating as a symmetrical bipole, located near the Koumoundourou EHV substation.
- The Crete station: It involves a new AC/DC converter station with a rated power of 1000MW (2 x 500 MW), voltage up to 500kV, operating as a symmetrical bipole, located near Damasta, Crete.

(d) Crete HV transmission system infrastructure

Crete's HV transmission system will benefit through the installation of 150 kV Transmission Lines, but also from the contribution of:

- A Terminal Transition Station at Korakia for the transition of the underground DC cable to overhead DC line.
- A new 150 KV Coupling Substation (GIS) for the connection of the AC/DC Converter Station to the AC 150 KV Crete system.

(e) Electrode stations

Two electrode stations are foreseen:

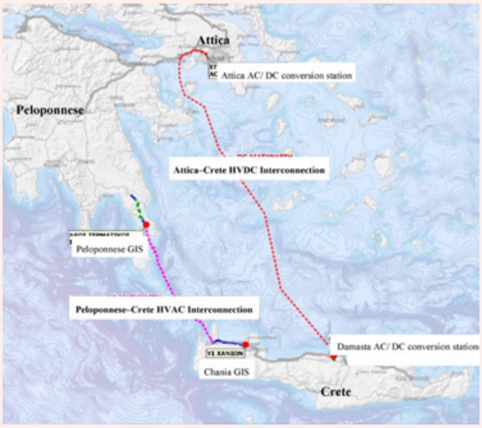
- The Attica side electrode station to be located on the small island of Stachtoroi.
- The Crete side electrode station to be located in Korakia.

Benefits

The mainland Greece to Crete electricity interconnection will result in a number of financial, infrastructure and environmental benefits as follows.

- 100% reduction of Services of General Interest (SGI) charges passed on the consumers of an estimated € 300-400 million per year
- Ensuring 100% adequacy of power supply in Crete in the long term
- Full utilization of the local potential of Renewable Energy sources
- Significant improvement of the island's environment following the retirement or mothballing of fuel oil and diesel power generation plants

Map 10.4 **Greece's Two Crete-Mainland Electricity Interconnections**



Source: IPTO

Energy Storage

The emergence of intermittent renewable energy and its growing participation in the electricity mix, combined with intensified decentralization of generation sources presents ever-increasing demands in the management of the grid. In this environment, energy storage gains greatly in importance since it increases the system's ability to accommodate variable wind and solar output, balance fluctuations in supply and demand and deal with local congestion issues. A wide range of storage technologies with different characteristics regarding capacity, efficiency, duration and response time are being introduced in the market to help maintain grid stability, voltage control, operating reserve, dispatch and re-dispatch as well as for simple price arbitrage.

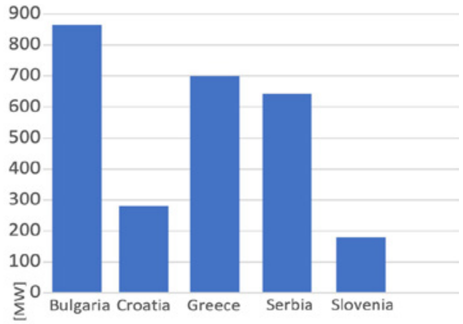
At European level, Directive (EU) 2019/944 on common rules for the internal market for electricity, the European Commission's position on energy storage in the electricity market is thoroughly documented. According to the directive, Member States' energy policies should not be designed in a way that unduly discriminates energy storage compared to other players and technologies. To ensure market competition and keep costs down, TSOs and DSOs are restricted from owning and operating energy storage facilities, except under special circumstances in which no other parties have expressed interest, or where the storage facility is necessary for fulfilling the system operator's (TSO or DSO) obligations[26]. EU Member States have to incorporate the necessary adjustments into their national law by 2021. Battery Energy Storage Systems (BESS) represent one of the fastest expanding energy storage technologies. Thanks to their quick response times, their capacities are increasingly procured in the ancillary services market for frequency control purposes. They can also be used to cover peak demand or for energy shifting. The latter means that energy is stored at times of low prices and surplus supply, and discharged at a later point, when scarcity in the system drives power prices up. Additionally, battery facilities can be used as an alternative to network reinforcements that might require expensive upgrades. Batteries also offer a way to optimize self-consumption from in-house renewable generation sources, be it at industrial or residential scale. Last but not least, their use in electric vehicles makes batteries one of the key enablers of a low-carbon economy. In SEE only two countries have deployed grid scale BESS, namely Slovenia and Hungary. In Hungary energy producer ALTEO in collaboration with Wartsila has deployed a battery energy storage facility, with a capacity of 6 MW / 4 MWh[27]. In Slovenia NGEN has deployed the first utility scale battery energy storage facility in the Balkans with capacity of 12.6 MW / 22MWh, using Tesla's modules[28]. Moreover, potential for grid scale battery applications is identified in Greece, where high intermittency of renewables, the weak grid infrastructure and inadequate power sources in island systems present an opportunity for BESSs' rollout. A pilot hybrid system in the island of Tilos in Greece is currently testing the integration of a 2.6 MWh NaNiCl2 battery system.

Pumped hydropower storage is a mature energy storage technology with a variety of applications in SEE Europe. Pumped storage hydroelectric plants are the most flexible and widespread means for the large-scale storage of electricity. By transferring water between two reservoirs at different elevations it is possible to supply electricity during peak demand and store excess electricity during periods of low demand. Pumped storage technology has a very good overall yield of about 80%, which means that 100 MWh of excess energy stored will enable the production of around 80 MWh of energy during the next peak in energy consumption. The response time of pumped hydropower storage stands below 2 minutes and is clearly lacking in comparison to BESS, which require only milliseconds. Still, its notably lower cost (given the spatial circumstances) and larger life time span makes it a more viable and

[26] https://www.europarl.europa.eu/RegData/etudes/BRIE/2017/595924/EPRS_BRI(2017)595924_EN.pdf
[27] h https://www.pv-magazine.com/2018/08/23/wartsila-completes-its-first-european-energy-storage-project/
[28] https://www.energy-storage.news/news/slovenia-becomes-first-balkan-state-to-install-grid-scale-tesla-ess

scalable storage option. Most of the installed pumped storage hydroelectric plant capacity in SEE is located in Bulgaria, Greece and Serbia.

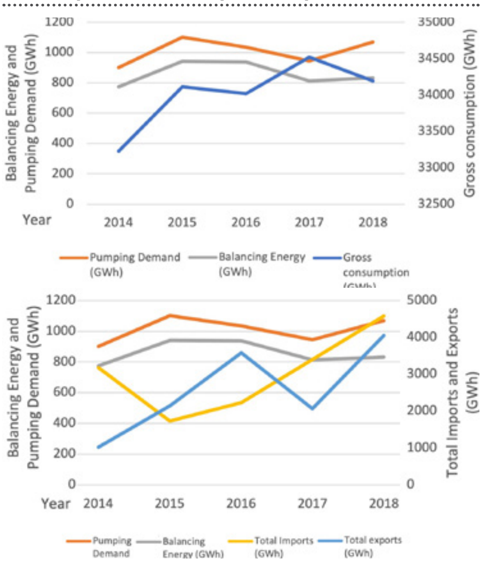
Figure 10.2 **Pump storage installed capacity in SEE**



Source: Entso-e

In Serbia's power system, flexibility is offered by the discharges of large hydropower units, which however are bound by seasonal demand and precipitation leaving an important role for the hydro pump storage capacity of the country. It is evident that the total balancing energy in Serbia is related to the utilization of pump storage units, as shown by the relationship of annual pumping energy demand with the corresponding annual balancing energy trend in figure 10.3.

Figure 10.3 **Relation of pump storage demand in Serbia with balancing energy, considering (a) Gross consumption and (b) Imports/Exports**



Source: AERS, Entso-e

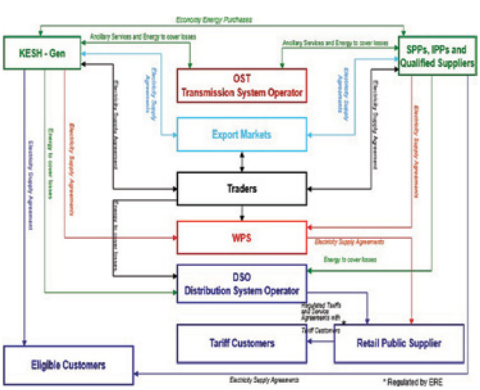
In Greece, Bulgaria but also in Croatia and Slovenia, which also present notable capacities of installed pumped storage hydropower plants, hydropower generation from such units is mostly used to cover peak demand.

10.3 Market structure, ownership and regulation

Albania

In Albania according to Law No.43 / 2015 "On the Electricity Sector", the Regulatory (ERE) is responsible for defining the rights and obligations of market participants and for ensuring regulatory control in the Albanian electricity market. The current Law on Electricity Sector gives ERE the authority to approve the "Rules of Operation of the Electricity Market". The Transmission system Operator, OST, is the independent state company that carries out (a) the Physical Operation function of the transmission grid (ownership, maintenance and expansion), (b) the System Operation function including the dispatching, (c) the assurance of connectivity services to all the system users, connected with the transmission grids, on non-discriminatory conditions, (d) determines the conditions to become a Balancing Responsible Party (BRP) and a Balancing Service Party (BSP) and (e) implements the cross-border interconnection capacities calculation, coordinated and in accordance with the requirements set on regional organized markets.

Figure 10.4 **Albanian Electricity Market Structure - Energy Supply Agreements**



Source: ERE

OST also performs the function of the Balancing Market Operator by (a) forecasting and purchasing ancillary services, divided into balancing energy and reserve capacity by all the Balancing Service Providers (BSP), (b) by performing the necessary actions for balancing, by activating the decreasing (Downward) or increasing (Upward) secondary regulation by the balancing reserves and/or additional balancing reserves, offered on the balancing electric power market and (c) by purchasing the transmission losses, in the day ahead organized market. Therefore, OST compensates BSPs for the balancing services, assuring the financial settlement on a monthly basis, through the compensation of imbalances, based on the rules for imbalances calculation, providing proper incentives for market participants, to be balanced in real time and close to real time. Rules of imbalances calculation reflect deviations between the electric power generation, electric power trade and the consumption of the balancing responsible parties and the equilibrium of each Balancing Responsible Party. Compensation is based on a single price system, by penalizing deviations in both directions.

OST also manages the required collection of the measurement data, to perform an efficient management of the imbalances and their financial settlement and calculates the electric power imbalance price to be paid by the BRPs based on the real costs for the TSO, to balance the system for the respective period, covering balancing reserves and energy reserves. Fees, terms and conditions of access to the transmission system are regulated by the ERE.

Until the deployment of the Albanian Power Exchange, **ALPEX**, OST acts as a Market Operator with the responsibility of: (a) Collection and processing nomination data from market participants, (b) collection and processing of metering data, (c) manage the settlement statement process, (d) maintain financial obligation for ancillary services and transmission losses, (e) service of Interconnection Capacity Allocation.

The Distribution System Operator (DSO), OSHEE, possesses, maintains, expands and operates the electric power distribution system and is separated from the supply, in accordance with the rules of the Energy Community. OSHEE provides the connectivity service to all system users, connected to the distribution network, on non-discriminatory conditions. Additionally, OSHEE carries out the procurement of technical and non-technical losses, in the organized day ahead market (ALPEX)[29]. For an intermediate period, when the trade product availability on the organized market does not allow the purchase of losses at an optimal cost, the procurement procedures are allowed for the DSO, in accordance with the rules approved by ERE. Fees, terms and conditions of access to the distribution system are regulated by ERE. OSHEE is responsible for reducing the technical and non-technical losses in the distribution system, with ERE establishing a relevant fee for the DSO, which provides an incentive to reduce these losses. Moreover, OSHEE is also a Balancing Responsible Party.

Balancing Responsible Parties (BRP) are all judicial entities, which possess generation and consumption units, interconnected and on a fixed capacity determined by the TSO and approved by ERE and are regulated by an agreement between each BRP and the TSO. Also, every trader which trades in Albania or supplies cross-border electric power is a BRP. BRPs are allowed to schedule the physical bilateral contracts for buying/selling the capacities allocated in the SEE CAO. All long-term domestic OTC trades are based on a financial contract, where the physical electric power is traded by APEX[1] and the APEX's price is the reference price for the financial contract. ERE will approve the OTC financial template contract. All the BRP's will be responsible for the imbalance calculation. A BRP may assume the responsibilities of other BRP's or production and consumption units, under an approved capacity. All BRP's are responsible for their production and consumption forecast.

[29] Not yet implemented (February 2021)

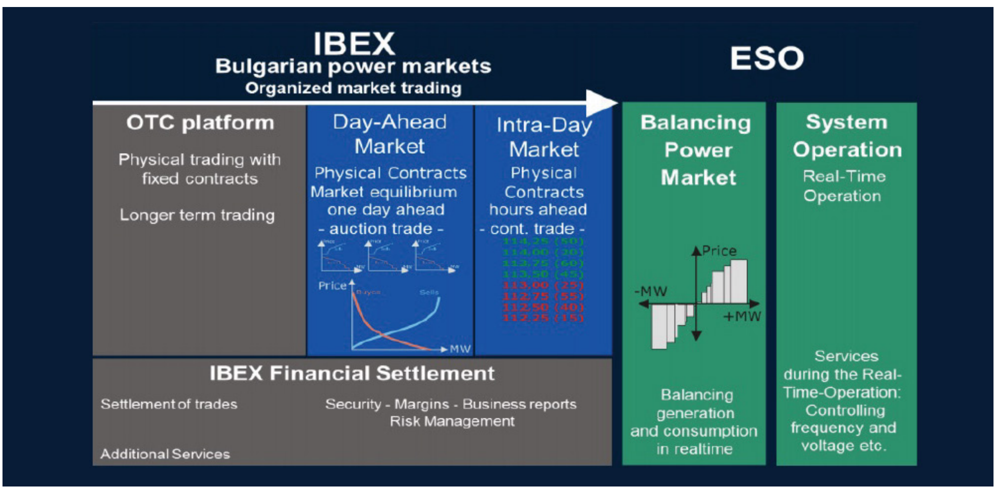
Bulgaria

The Energy and Water Regulatory Commission (EWRC), previously ERC, was established in September 1999 and currently is the regulatory authority for energy of Bulgaria. Its main competences are: (a) issuing, amending, suspending, terminating etc. licenses for activities in the energy sector (generation, electricity trade, imports, public provisions etc.), (b) adoption and publication of basic guidelines, (c) adoption of secondary legislative acts, provided in the EA, (d) approval of the common conditions of the contracts, provided in the EA, (e) approval of work rules for energy services for consumers, (f) exercise control, analyze, periodically review and request amendments of the pricing mechanisms (g) monitor the implementation of all measures adopted, (h) carry out price regulation, (i) adoption of Electricity Market Rules at the proposal of energy companies, (j) adoption and monitoring compliance with Rules for electricity supply, (k) adopt and control the application of a balancing electricity pricing methodology, (l) lay down Rules for access to the electricity and gas transmission network, (m) undertake the organization of competitive procedures Art. 46 of EA and more[30].

IBEX (Independent Bulgarian Energy Exchange) has been in operation since early 2016 with the purpose to regulate free trade, to ensure that electricity prices are set on a free market basis, and to bring transparency in the trading of energy[31]. It was established in January 2014, as a fully-owned subsidiary of the Bulgarian Energy Holding EAD. IBEX holds a 10-year license (No-422-11) by the State Energy and Water Regulatory Commission for organizing a Power Exchange for electricity in Bulgaria. IBEX is a full member of the MRC (Multi-Regional Coupling), as well as an associate member of the PCR (Price Coupling of Regions) and is responsible for establishing and developing organized electricity market in Bulgaria based on transparent and non-discriminatory principles[32].

Furthermore, according to EWRC's decision HO-1/27.01.2016, IBEX is designated as the nominated electricity market operator for the territory of Bulgaria in accordance with Regulation (EU) 2015/1222, establishing guidelines on capacity allocation and congestion management, for a period of four years[33].

Figure 10.5 **Conceptual design of Bulgarian electricity market**



Source: Nord Pool consulting

30 http://old.dker.bg/pageen.php?P=417
31 http://www.dker.bg/bg/za-kevr/godishni-otcheti.html
32 http://www.ibex.bg/en/about-us/profile/
33 http://www.ibex.bg/en/announcements/news/ibex-is-designated-as-nominated-electricity-market-operator.html

The Electricity System Operator (ESO) is the Transmission system Operator of Bulgaria. Its obligations as set out by the energy act and its bylaws and cover the following: (a) control and operational planning of the Bulgarian power system, (b) the coordination of the Bulgarian system's parallel operation with Entso-e member TSOs as well as the joint operation with other systems, (c) transmission grid operation and maintenance and (d) balancing market organization. Its goal and tasks, in accordance with the legal and administrative acts of the State Energy and Water Regulatory Commission (SEWRC) and the Ministry of Economy, Energy and Tourism (MEET), as well as with the strategic and operative objectives of BEH EAD include the (a) improvement of security of electricity supplies, (b) boosting the investment appeal of the Bulgarian power sector, (c) enhance transparency and good management practices, (d) improved operational efficiency, (d) increased investment potential, (f) holding maintenances of transmission facilities in line with the technical requirements and in order to guarantee the grid's efficient functioning[34].

In terms of electricity supply, the retail market consists of three groups of suppliers:
- free market supplier
- trader / manufacturer / exchange that supplies electricity to household and non - household consumers at prices determined on the basis of supply and demand;
- supplier of last resort - supplier who guarantees the provision of universal service as a last resort, in accordance with a license obtained from EWRC, has an obligation to supply electricity to customers who are connected to the grid and have not selected an electricity supplier or when the supplier chosen by them is incapacitated from making delivery, independent of customer behavior.

The final selling prices for the supply of last resort are determined according to the relevant EWRC determination methodology.

- final supplier (CS) of electricity, who supplies electricity at regulated prices, approved by EWRC, for end-use household customers. Three such vertically connected energy companies are actively operating in the retail electricity market, CEZ Group, EVN Group and ENERGO-PRO Group.

Croatia

In Croatia the electricity sector is regulated by **Energy Regulatory Agency (HERA)**, an autonomous, independent and non-profit public institution, which regulates all energy activities in the Republic of Croatia. HERA's obligations, authorities and responsibilities are based on the Act on the Regulation of Energy Activities, the Energy Act and other acts regulating specific energy activities. HERA's main competences with regard to the electricity sector include, (a) the issuance, prolongation and transfer of licenses to perform energy activities including the status of eligibility for energy producers, (b) monitoring of energy activities in respect to compliance with applied legislation, unbundling provisions, transparency, objectiveness and non-discrimination against market participants, (c) giving approval to the market rules for electricity, (d) adopting methodologies i.e. tariff systems in accordance with current legislation at play (e) fixing or approving prices, amounts of tariff items and remunerations in accordance with methodologies in effect, (f) monitoring the compatibility of energy investment plans with the plans of ENTSO-e and domestic plans to address issues such as regional interconnectivity and security of supply, and many more.

Croatian Energy Market Operator (HROTE) started to operate on 4 April 2005. HROTE performs activities related to the organization of the electricity and gas market as a public service, under the supervision of the Croatian Energy Regulatory Agency (HERA). In addition, HROTE performs activities for incentivizing electricity production from renewable sources and cogeneration.

[34] http://www.eso.bg/fileObj.php?oid=99

Its main responsibilities in the electricity market include (a) issuing Electricity Market Rules, (b) keeping records of participants on electricity market, (c) registration of contractual obligations among market participants, (d) preparation of a day ahead market plan, (e) settlement of balancing energy, (f) analyzing the electricity market and recommending measures for its improvement. Moreover, HROTE has a major role in the Croatian system of incentives, where it approves contracts with incentivized eligible producers and all suppliers regarding regulated purchasing of minimal share of electricity produced from renewables and cogeneration (RESCO), while it is also charged to collect from suppliers and settle the collecting fee for RESCO according to the active contracts[35].

In Croatia the local TSO, the Croatian Transmission System Operator, (HOPS) is charged with ensuring the electric power system operation and maintenance, electricity transmission, as well as construction and development of electricity transmission network in order to maintain security of supply with minimal costs and environmental protection. Subsequently, HOPS is also charged with dispatching power plants and using interconnectors with other networks based on criteria that must be objective, publicly available and non-discriminatory.

In this regard it is also responsible for the allocation of cross-border transmission capacities and adopting objective, transparent and non-discriminatory rules pertaining to system balance, including the rules for charging balance responsible parties for imbalances. Additionally, HOPS is also responsible for absorbing the total amount of electricity generated by eligible producers, i.e. RES and high efficiency generation[36].

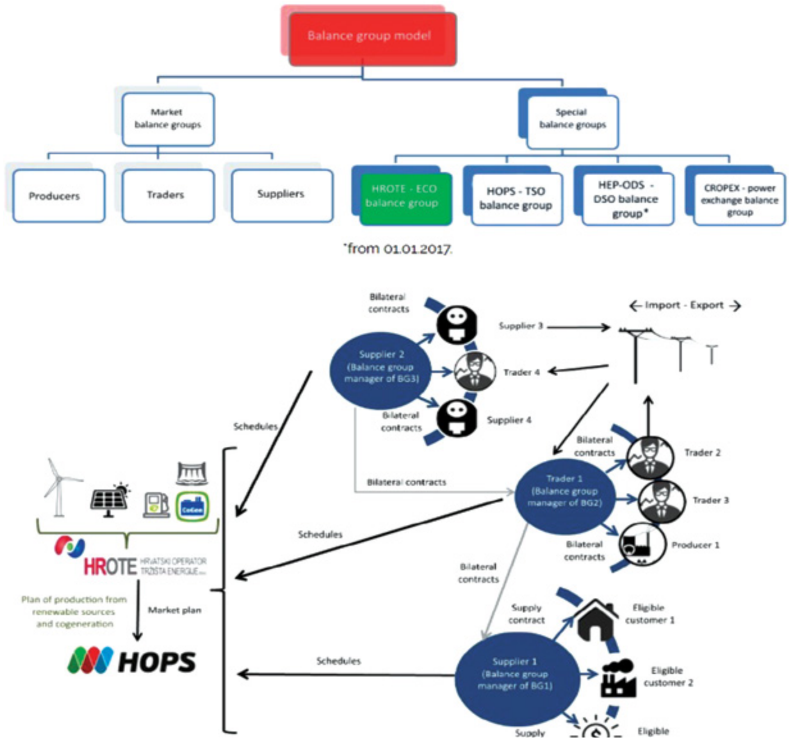
HOPS, previously HEP-Transmission System Operator Inc. (HEP-OPS), was established, and began operating on April 4th, 2005 in accordance with the Energy Act, the Act Amending the Energy Act and the Electricity Market Act. HEP-OPS was inscribed into the Commercial Court Register in Zagreb, underwent an equity capital increase and was renamed Croatian Transmission System Operator Ltd. (abbreviated HOPS d.o.o.). HOPS is the sole electricity transmission system operator in the Republic of Croatia, and the owner of the entire Croatian transmission network (400 kV, 220kV and 110kV included voltage levels).

Croatian Power Exchange Ltd. (CROPEX) is a company established to provide a central location for trading electricity to its market participants in a safe, reliable and transparent way. CROPEX Ltd. acts as Central Counter Party between sellers and buyers of electricity and takes the risks of buying and selling electricity for all day-ahead and intraday trades concluded on its trading platform.

The Croatian Power Exchange Ltd. is equally owned by Croatian Energy Market Operator Ltd. (HROTE) and Croatian Transmission System Operator Ltd. (HOPS) (50%/50%)[37]. CROPEX was established in May of 2014, was designated by HERA, as Croatia's NEMO in 2015 and commenced operation of the day ahead market framework in February of 2016. In December 2019 CROPEX was re-designated as Croatia's NEMO[38].

35 https://www.hrote.hr/about-us
36 https://www.hops.hr/en/business-activity
37 https://www.cropex.hr/en/about-us.html
38 https://www.europex.org/members/cropex/#:~:text=CROPEX%20%2D%20Croatian%20Power%20Exchange&text=was%20established%20in%20May%202014,transparent%20solution%20for%20electricity%20trading.

Figure 10.6 **Croatia's energy Market Scheme**



Source: HROTE

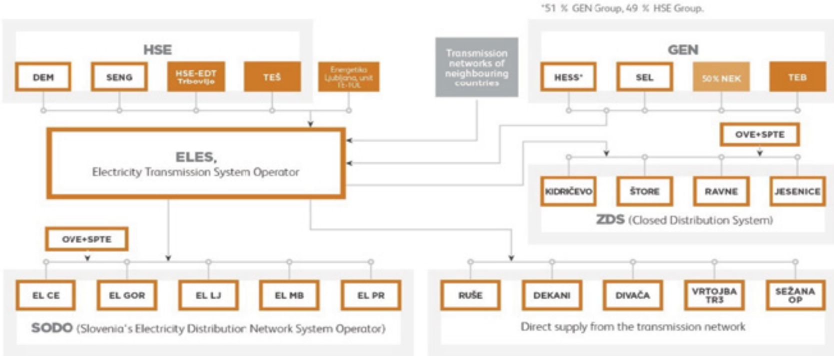
Slovenia

In Slovenia the regulatory authority for energy, the **Energy Agency - Agencija za energijo (AGEN-RS)**, was established in 2001, and its purpose is to ensure the conditions for the development of competitive energy markets and ensuring their operation by taking into account the requirements for sustainable, reliable and high-quality supply. Moreover, with regard to the electricity sector, the Energy Agency is charged with, (a) the regulation of the electricity network activities, (b) the promotion of the production of electricity from renewable sources and cogeneration, (c) monitoring the electricity market, (d) monitoring the activity of energy operators and (e) the protection of the rights of consumers under the legislative rules enacted by Energy Act of 2014 [39].

ELES is the operator of the electric power transmission network of the Republic of Slovenia. Its role is to plan, construct and maintain Slovenia's high-voltage transmission network in three voltage levels: 400 kV, 220 kV and a part of 110 kV, in a sustainable and strategic manner. The role of ELES is to interconnect all the main actors in the Slovenian electric power transmission network, namely power plants providing electric power for the transmission network, five larger consumers, the so-called direct customers, which offtake electricity from the transmission network and four larger consumers (steel-works and TALUM) with the status of a closed distribution system as shown in Figure 10.7.

[39] https://www.agen-rs.si/web/en/tasks-of-the-energy-agency

Figure 10.7 **Slovenia Power System Scheme**



Source: ELES

In Slovenia there are two 100% publicly owned major electricity producers Holding Slovenske Elektrarne (HSE) and GEN Energija (GEN). HSE owns and manages a series of electricity production plants, primarily hydropower. GEN Energija manages the Krsko nuclear plant as well as several hydropower units[40]. In Slovenia there are five distribution system operators, operating respective distribution networks.

Borzen, a publicly owned entity was the electricity market operator of Slovenia until 2008, when its role was assigned to BSP Southpool. The company's principal activity is the implementation of public service obligation relating to the organisation of the electricity market that includes organisation of the electricity market in the strict sense and the activities of the Centre for RES/CHP Support. It was founded on 28th March 2001 and as a Power Market Operator, provides and facilitates coordinated operation of the Slovenian electricity system. Borzen is charge with the (a) execution of activities of electricity balance scheme management, (b) recording of closed contracts, (c) elaboration of indicative operating schedule, (d) imbalance settlement and (e) financial settlement of transactions, all connected with the aforementioned activities. Borzen also operates a Centre for RES/CHP support, which is the support scheme operator for the generation of energy from renewable energy sources and highly efficient cogeneration of heat and power, while it also stimulates environmental policies and promote public awareness[41]. The electricity market in Slovenia is operated by **BSP Southpool**, established in 2008 and owned by ELES and Borzen. BSP was designated as Slovenia's NEMO on December 2015, and was charged with the task of implementing the single day-ahead and intraday coupling within the territory of the Republic of Slovenia, in accordance with the CACM regulation.

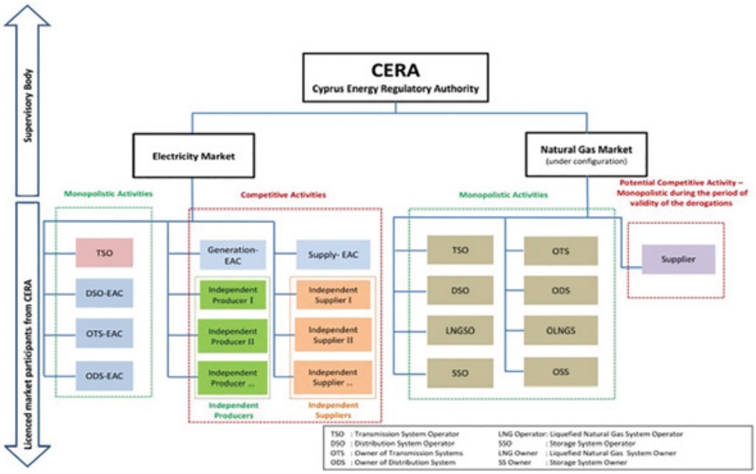
Cyprus

The National Independent Energy Regulatory Authority in Cyprus is the **Cyprus Energy Regulatory Authority (CERA)**, established in 2003. CERA has a wide range of duties, responsibilities, competences and authorities. With regard to the electricity sector and according to the Electricity Market Regulation, CERA's objectives, powers and responsibilities primarily are (a) to inform and protect consumers, (b) to promote Renewable Energy Sources, (c) to encourage and facilitate genuine competition in the Electricity Market, avoiding adverse discrimination and aiming ultimately at reduced prices, (d) to ensure adequacy in electricity supply for the satisfaction of all reasonable needs and demands for electricity, (e) to regulate tariffs, charges and other terms and conditions to be applied by Licensees, for any services provided according to the terms of

[40] https://www.export.gov/apex/article2?id=Slovenia-Electrical-Power-Systems
[41] https://www.borzen.si/en/Home/menu1/About-us/Short-presentation

their Licenses, (f) to prepare and implement long-term planning regarding capacity for generation, transmission and distribution on a long-term basis, in order to meet the demand for electricity in the system and to secure supplies to customers. The planning activity includes security of supply, energy efficiency / demand-side management and achievement of environmental objectives and targets for energy from renewable sources.

Figure 10.8 **Cyprus Energy Market Scheme**



Source: CERA

The **CTSO**, the TSO of Cyprus in alignment with Electricity Market Regulation Amendment Law 2012, N211 (I) / 2012 of 13 December 2012, is responsible for the efficient, coordinated, safe, reliable and economically viable operation of the electricity transmission system. Moreover, CTSO is charged with the development and maintenance of an insured, reliable, cost-effective and efficient transmission system. Additionally, CTSO's role is to investigate and promote any prospects for the interconnection of the transmission system with other systems and to ensure the availability of all production services and other services necessary to carry out its responsibilities. CTSO carries out the operation of the load distribution system and the use of the transmission system, with objective, non-discriminatory, economic and technical criteria, in accordance with the Transmission, Distribution and Electricity Market Rules[42].

EAC the E**lectricity Authority of Cyprus** is currently the owner of the transmission and distribution network while it is charged with the role of DSO for the island system as well as its main electricity producer and supplier. EAC is in the process of unbundling to comply with EU regulations. The unbundling procedure as well as the compliance for the unbundling provisions are supervised by CERA.

Romania

Romanian Energy Regulatory Authority (ANRE). The Romanian energy regulator is responsible for adopting regulations in the electricity and gas sectors, as well as in the energy efficiency sector. It has broad regulatory powers, mainly in relation to: (a) establishing the contracting framework in the energy sector, setting up prices and tariffs for the natural monopoly segments of the markets; (b) monitoring the electricity market and compliance with the existing regulations; and (c) authorizing and licensing companies in the energy sector.

[42] https://tsoc.org.cy/organization/general/

National Environmental Protection Agency. A public central administration authority, subordinated to the Ministry of Environment, with competences in the following areas: (a) strategic environmental planning and environmental factors monitoring; (b) permitting of activities which have an impact on the environment; (c) implementation of the environmental legislation and policies; (d) reporting to the European Environment Agency; (e) coordinating the implementation of environmental strategies and policies; and (f) permitting activities having an impact on the environment and providing the compliance with the legal provisions.

OPCOM, as operator of the electricity market, deals with the organization, management and settlement of centralized markets, in the short, medium and long term, with the exception of the balancing market for wholesale trading electricity.

The centralized markets in the electricity sector in Romania are the following:

(a) intra daily electricity market, Piața Intrazilnică (PI), organized and managed by the operator of the electricity market, which helps to improve balancing the portfolio of participants, for the day of delivery, through transactions in sessions held after the completion of transactions in the day-ahead market and before a certain time of delivery start;
(b) the market for allocating capacities for international interconnection, organized and managed by the transmission system based on specific rules, in order to achieve transactions of the import / export and transit of electricity.
(c) centralized market for bilateral contracts with continuous negotiation PCCB - NC;
(d) bilateral contracts market for green certificates PCBCV;
(e) centralized market with double continuous negotiation of electricity bilateral contracts PC-OTC;
(f) electricity market for large end-use customers PMC.

Distribution operators hold an electric power distribution license and they are responsible for operating, maintaining and developing the distribution system in a given area and the interconnections with other systems, as well as for ensuring the long-term ability of the network to meet reasonable demand of electricity distribution. Distribution services provided to customers consists of the transmission, in terms of efficiency and safety of electricity between two or more points of distribution network, in compliance with performance standards. Electricity transmission network remains a state property. Transmission and distribution of electricity are fully regulated natural monopolies.

Transelectrica, as the transmission system operator, has the ownership and the responsibility for the operation of the power transmission network, ensuring its proper maintenance and adequate development in a certain area. Moreover, Transelectrica is responsible for the interconnection of the power transmission network with other power systems, and for ensuring the long-term adequacy of the network. It is also in charge of maintaining the level of reliability of the power system, as well as the quality of electricity supply it provides. Also, it provides electricity transmission services between different parts of the power transmission network to net metering customers, other TSOs, to producers and distribution system operators.

The supplier of last resort is an electricity provider, which is designated by the competent authority to provide universal service for the supply of electricity to end consumers who have not secured supply of electricity from any other source. The suppliers of last resort shall be appointed by ANRE from the existing providers in the energy market through competitive mechanisms, based on a regulation which establishes the rules and criteria for their selection for each category of end-customers who they serve[43].

[43] https://iopscience.iop.org/article/10.1088/1757-899X/200/1/012067/pdf

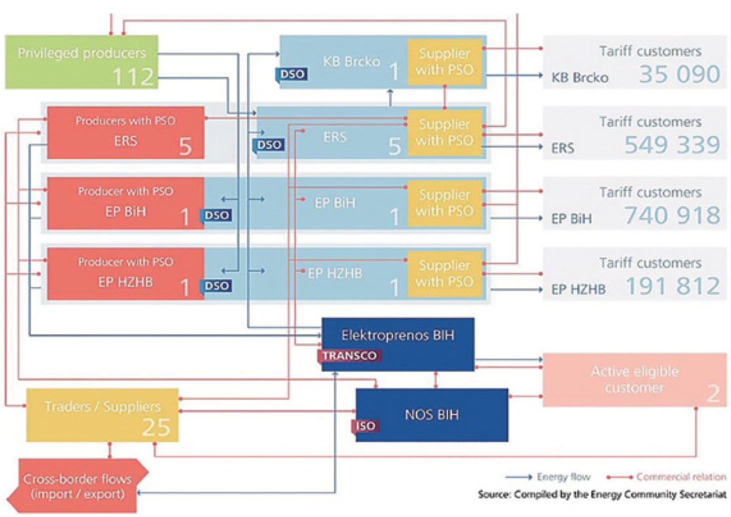
Bosnia and Herzegovina

In Bosnia and Herzegovina (BiH), there are three regulators responsible for different activities in the electricity sector. One at the national level, the **State Electricity Regulatory Commission (SERC) and two at entities level, the Regulatory Commission for Energy in the Federation of BIH (FERK) and the Regulatory Commission for Energy of Republika Srpska (RERS)**. The State Electricity Regulatory Commission (SERC) is an independent institution of Bosnia and Herzegovina, and has jurisdiction over and responsibility for the transmission of electricity (110kV and higher voltage level), transmission system operation (Independent System Operator) and international trade (cross-border) in electricity including the issuance of licenses for cross-border electricity trading, as well as generation, distribution and supply of electricity for customers in the Brčko District of Bosnia and Herzegovina.

FERK and RERS are the regulators responsible for the supervision of the electricity sectors in each of the BiH entities. RERS is responsible for the issuance of licenses for electricity production, distribution, supply and trading within BiH, as well as for the issuance of licenses for the construction of new and the reconstruction of existing power plants in the respective entity. FERK is responsible, inter alia, for the issuance, renewal, transfer or suspension of licenses for the production, distribution, supply, trade of electric energy and operator for renewable energy sources and cogeneration. In FBiH the Federal Ministry for Energy, Mining and Industry is the competent authority for issuing licenses (i.e. energy permit) for the construction of new or reconstruction of existing power plants.

The transmission level is organized in a way that there are two state companies ("NOS BiH" (ISO) and **"Elektroprijenos BiH"** (Transmission company) each with its own responsibilities. Elektroprijenos BiH, with ca 6.500 km of transmission network is responsible for maintenance and construction of the transmission grid, while the **Independent System Operator in Bosnia** and Herzegovina (ISO BIH) manages the operation of the HV network, balances the power market, determines the generation development plan and reviews the transmission network development. Independent System Operator of Bosnia and Herzegovina (NOS BiH) is a state-owned company responsible for

Figure 10.9 **Bosnia and Herzegovina's electricity Market Scheme**



Source: Compiled by Energy community Secretariat the direct operation of all high voltage transmission facilities (110 kV and above) in B&H. The main functions of NOS BiH are: (a) Operate central control center facilities and any remote control facilities; (b) Administer the balancing market; (c) Procure ancillary services and provide system services; (d) Prepare, modify and administer reliability standards, the market rules and grid code; (e) Coordinate and approve the scheduling of planned outages of transmission and generation facilities, and coordinate and approve changes to outage schedules; (f) Review, endorse, direct revisions to and publish the long-term transmission development plan submitted by the Transmission Company; (g) Develop an indicative generation development plan with data supplied by the generators, distribution companies and end-use customers directly connected to the transmission system.

BiH does not yet have an organised electricity day-ahead market or any power exchange. The Market Rules approved by SERC in 2015 provide a basic framework for wholesale trading and do not prevent the establishment of an organised electricity market operator. However, the state Law does not define competences for establishing such a legal entity, which prevents the setting up of an organized market. Currently, the wholesale market has been organized based on bilateral transactions (bilateral market) between licensed market participants. The ISO BIH registers all transactions in terms of quantities for settlement purposes.

Trading in the wholesale market in BIH, which is based on bilateral contracts between traders/suppliers, is dynamic. Although this market has not been institutionalized yet, the registration of numerous bilateral contracts has been significant. In 2018, a total of 20 licensed entities were active and traded 7.395.467 MWh. Licensed participants in the bilateral market, trade in different time frameworks and with different products (i.e. day-ahead, week ahead, month ahead, year ahead).

In addition to the wholesale markets, the balancing market operated by the Independent System Operator in BIH is the most advanced market segment in Bosnia and Herzegovina, with competition taking place between four utilities and one industrial customer. The Market Rules of 2016 allowed the independent system operator NOS BiH to operate a competitive balancing market within the territory of Bosnia and Herzegovina, including both balancing reserve capacity and balancing energy. The balancing mechanism is continually improved, and the rules were amended in 2018 to meet the diversification of services and types of bids and nominations. Essentially, on the balancing market ISO BiH (system operator) is on demand side, while on the supply side there are mostly generators providing ancillary services (capacity and energy for secondary and tertiary control and energy for covering losses in the transmission system).

On the balancing market ISO BiH procures balancing services based on annual, monthly and daily auctions. Participation in the balancing market is voluntary and all technically capable providers can participate.

Greece

In Greece the electricity sector is regulated by the **Regulatory Authority for Energy (RAE)**. RAE is an independent regulatory authority established by Law 2773/1999, which transposed Directive 96/92/EC into the Greek legal order, and it is empowered to provide: (a) advisory, monitoring and control competences in all sectors of the energy market according to Law 2773/1999, (b) evaluation of the applications for a production license for RES units according to the provisions of Law 3851/2010, (c) biding decisions in relation to all relevant regulatory issues for the electricity and natural gas markets to function properly based on provisions provided by the Third European Energy Package[44].

[44] https://www.rae.gr/%CF%83%CF%87%CE%B5%CF%84%CE%B9%CE%BA%CE%AC-%CE%BC%CE%B5-%CF%84%CE%B7-%CF%81%CE%B1%CE%B5/?lang=en

RAE's roles were enhanced and well determined by the Energy Law 4001/2011 and notably include:

- Monitoring and surveillance of the energy market
- supervision of the application of Consumer Protection measures
- Monitoring the country's energy security of supply
- Licensing of all energy-related activities
- Monitoring and certification of Independent Transmission System Operators
- Monitoring of Development Plans by the competent TSOs
- Approval of tariffs for non-competitive services
- Monitoring access to energy interconnections and granting exemptions from third party access obligations
- Providing regulatory measures for the effective functioning of energy markets

IPTO is Greece's Transmission System Operator (TSO) and is charged with the responsibilities and performs the duties of Owner and Operator of the Hellenic Electricity Transmission System (HETS), in accordance with the provisions of Law 4001/2011 the requirements in the Grid Code and the HETS operation license. The mission of IPTO is the operation, control, maintenance and development of the Hellenic Electricity Transmission System in order to ensure the country's supply with electricity in an adequate, safe, efficient and reliable manner, as well as the operation of the electricity market for transactions outside the Day Ahead Scheduling, pursuant to the principles of transparency, equality and free competition.

Due to IPTOS's critical role the company is guaranteed independence with strict adherence to the "equal treatment" principle for all System Users and Participants in the Electricity Market, transparency in its operation and respect of the confidentiality of the information which IPTO manages. IPTO's is currently state owned by 51%, 24% of its shares are owned by State Grid of China, IPTO's strategic investor, and 25% of its shares are listed in the Athens stock exchange.

Hellenic Energy Exchange S.A. (HEnEx) is Greece's Nominated Electricity Market Operator and is part of the EnEx group and was founded on 2018 as a spin-off from the electricity market branch of LAGIE S.A., the then government-controlled market operator. Henex has been designated by the Greek Regulatory Authority for Energy as the Nominated Electricity Market Operator (NEMO) and is operating the Greek day-ahead market, the intraday electricity market and the energy derivatives market. HEnEx is also responsible for organising and operating gas and environmental markets. Its subsidiary, EnEx Clearing House S.A. (EnExClear) provides clearing and settlement services including the Balancing Market which is operated by IPTO. HEnEx operates with transparency, and without discrimination in providing services to all market participants. HEnEx is working towards the EU's target model and coupling its market with neighbouring countries. To that end, HEnEx has become a full member of the Price Coupling of Regions initiative and is the responsible party for the proceedings for its expansion in Greece. HEnEx is 49% state owned, of which the institutional investors are DAPEEP, IPTO and DESFA holding 22%, 20% and 7% of the respective shares, while the private sector owns 51% of which 10% is owned by European Bank for Research and Development (EBRD) and 10% by the Cyprus Exchange (CSE).

The Administrator of Renewable Energy Sources and Guarantees of Origin (DAPEEP SA) manages the RES and the High Efficiency Cogeneration of electricity and heat in Greece's National Interconnected System, as well as the power generation that has been supplied by RES and cogeneration units. DAPEEP is also charged with holding auctions for emission rights in Greece according to the European ETS, while at the same time it operates as a RES Aggregator of last resort, representing RES producers in the organized electricity market. DAPEEP's strategic goal is to become the main pillar of RES development in the country, by securing and strengthening a viable operational framework that will ensure investment viability for RES producers and consumer protection from electricity market exposure towards a less carbon intensive future for the energy sector. With respect to the latter, DAPEEP operates also as an aid provider for the energy-intensive Industry (Carbon Leakage, etc.) and contributes in the strengthening its competitiveness. DAPPEP is the largest single shareholder in the HEnEx and the second largest seller of electricity in the organized electricity market after PPC.

Hungary

In Hungary the electricity sector is regulated by the **Hungarian Energy and Public Utility Regulatory Authority (MEKH),** an independent regulatory body which was founded by Act XXII of 2013. The Authority is responsible for licensing, supervisory, price regulation and price and fee preparatory tasks related to electricity, natural gas, district heating and water utility supply. MEKH performs tasks related to the uniform national energy statistics and fulfills its obligations to supply data to national, international and other organizations as an official statistical agency.

In the supply chain of the electricity system, power plant companies sell the electricity generated to traders or universal service providers (commercially), who, in turn, resell electricity on the wholesale market or supply customers directly on the retail market. Electricity is supplied to the user from the producer (physically) through the transmission and distribution network. Although the owners of the transmission infrastructure have a monopoly, the Hungarian regulations, which are in line with EU requirements, ensure access to the infrastructure without discrimination. The transmission and the distribution activities are performed by different companies, who do not pursue power generation or trading activities in accordance to EU unbundling rules.

The sale of electricity generated from renewables or waste falls within a special category. The feed-in scheme operator, MAVIR Zrt., is obliged to purchase such electricity from generators in the framework of the feed-in scheme (KÁT) (at a price determined by the law and in the volume and period of time determined in the decision issued by MEKH).

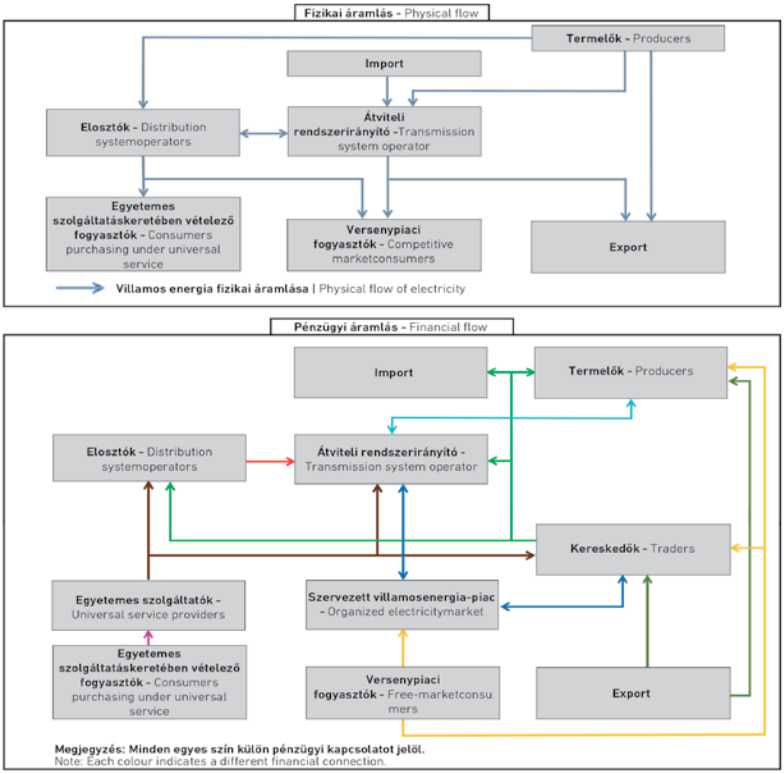
MAVIR Hungarian Independent Transmission Operator Company Ltd. (MAVIR) is Hungary's TSO and power system operator with the main task of safeguarding the uninterrupted, secure and sustainable operation of the Hungarian Electricity System. Moreover, MAVIR is charged with the obligation to (a) provide access for each system user on equal basis (b) to ensure an economical and efficient operation of the transmission network, (c) to ensure the effective and economically efficient operation and extension of the electricity market and (d) to ensure the proper operation of the market of ancillary services and the balance group system, facilitating market activities, (e) including the management of cross-border transmission capacities. MAVIR even though it belongs to MVM Group, it operates as an independent member in accordance to the rules for Independent Transmission Operators[45].

In Hungary there are currently 6 DSOs operating respective distribution networks across the country, under license by MEKH.

The Hungarian Power Exchange Ltd. (HUPX) is the operator of the organized Hungarian spot power market, and it was established in 2010 as a subsidiary of the national TSO MAVIR. HUPX is licensed as a NEMO (Nominated Electricity Market Operator) by the National Regulatory Authority of Hungary (MEKH). The core activity of HUPX is to provide a secure platform for effective electricity trading within the Hungarian framework, which is currently operating on the day ahead and on the intraday framework, while providing unified access for all participants, and efficient use of resources, as well as value-for-money transaction costs and clear settlement prices as a reference.

[45] https://ec.europa.eu/competition/publications/cpn/2007_1_23.pdf

Figure 10.10 **Hungary's electricity Market Scheme**[46]



Source: MAVIR

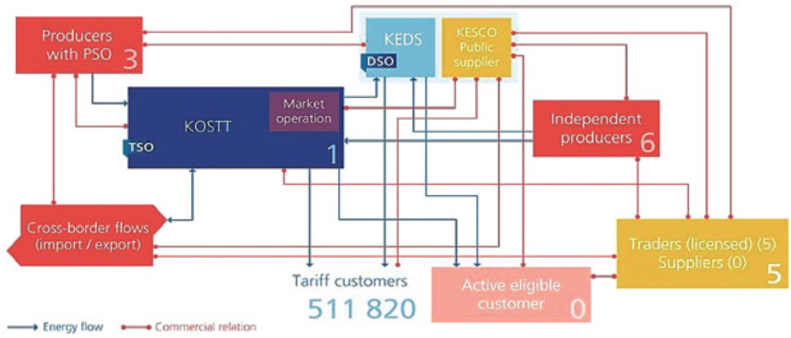
Kosovo

In Kosovo, the **Energy Regulatory Office (ERO)** was established in June 2004, with the announcement by Parliament of the Law on Energy, Law on Electricity and the Law on Energy Regulator. The energy regulatory Office is an independent body, which has a duty to regulate activities in the Energy Sector in Kosovo, including electricity, district heating and gas, in accordance with the obligations arising from the Energy Community Treaty aiming on the establishment of a legal framework for an integrated energy market. ERO has the power to issue licenses and monitor whether those licenses are respected by energy companies, adopt tariffs for public service activities, impose obligations on population supply, dispute resolution and draft secondary legislation for the energy sector. ERO is also responsible for creating a regulatory framework that ensures transparent and non-discriminatory functioning of the energy market, based on free market principles. It implements transparent and open criteria for granting licenses to energy undertakings, including the power to grant, modify, suspend, transfer, receive, supervise and control whether such energy enterprises are subject to these licenses.

ERO also has the power to set in advance the principles and methods of price setting and later to approve tariffs for regulated energy services. This feature also includes fee monitoring, dispute resolution, quality of service, and performance standards. In carrying out its activity, ERO cooperates with energy companies and ministries, especially with the Ministry of Economic Development and assists and ensures that the Kosovo regulatory framework is in line with the 'acquis communautaire' (EU legislation) on energy.

[46] http://www.mekh.hu/download/8/35/e0000/a_magyar_villamosenergia_rendszer_2019_evi_adatai.pdf

Figure 10.11 **Kosovo's electricity Market Scheme**



Source: Compiled by Energy community Secretariat

The Transmission, System and Market Operator of Kosovo (KOSTT JSC), is a public company with 100% of shares owned by the Republic of Kosovo. KOSTT was established in 2006 after the transformation of the vertically integrated Kosovo Energy Corporation (KEK). KOSTT operates under two licenses issued by the Energy Regulatory Office (ERO), license for Electricity Transmission System Operator and license for Electricity Market Operator. According to the Law on Electricity, the Transmission System Operator manages the transmission system and is responsible for the operation of the transmission system in Kosovo in line with the license issued by the ERO. Transmission System Operator operates under the energy enterprise, organized as an independent joint stock company (KOSTT JSC). KOSTT owns the transmission system, which includes 400 kV/x kV substations, 220 kV/x kV substations, 110 kV/x kV substations, and high-voltage 400kV, 220kV and 110kV lines and it is responsible for: (a) Planning, operation, maintenance and development of Kosovo's electricity transmission system, (b) Efficient, economic and coordinated operation of the transmission system, including cross-border flows, (c) Balancing of the system, (d) provision of non-discriminatory access for transmission system users, etc.

Kosovo's Electricity Market Operator (MO) is responsible for the economic management of the electricity system and the operation and development of the electricity market. The Market Operator operates independently from any enterprise engaged in any electricity activity other than transmission.

The primary legislation describes MO as a legal entity responsible for the organization and administration of trade in electricity and payment settlements.

Kosovo Energy Distribution Services (KEDS), Kosovo's DSO, was established in 2009 and is a joint stock company, currently owned by Turkish companies Çalik Holding and Limak, which is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area throughout Kosovo's distribution system. KEDS has the exclusivity of managing electricity distribution and infrastructure throughout the 35 kV, 20 kV, 10 kV, 6 kV and 0.4 kV distribution network of Kosovo. In Kosovo's Electricity market «electricity supply» is performed by energy enterprises licensed by ERO to perform supply activities. Suppliers may supply electricity to all customers in-and outside Kosovo, while suppliers with public service obligations must offer electricity supply to:

- final customers, who enjoy the right of supply under the framework of universal services, to the extent that this right cannot be exercised under market conditions;
- final customers, who have lost their electricity supplier due to circumstances beyond their control for a period not exceeding sixty (60) days;

All suppliers purchase electricity for the supply of their final customers in the bilateral market and in the organized market at unregulated prices. The Regulator may impose public service obligations for electricity producers to sell electricity to suppliers with public service obligations for a limited period of time.

Montenegro

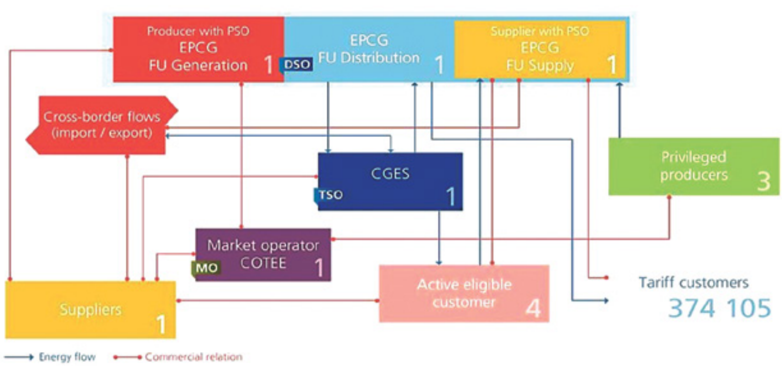
The **Energy Regulatory Agency** was established by the Parliament of Montenegro on January 22, 2004 in accordance with the Energy law, as autonomous, non-profit organization, legally and functionally independent from the state authorities and energy undertakings. The Agency is an independent regulatory authority with competences in the field of electricity, natural gas, oil and petroleum derivates and heating energy, as well as the competences in the area of utilities in the part relating to the regulation of prices for water supply and wastewater management. The objectives of the Agency are to contribute, in cooperation with the competent bodies of the Energy Community and regulatory organisations of other Energy Community members, to the promotion of a competitive, efficient, safe and by environmental protection sustainable electricity and gas markets in Montenegro. Within its competences, the Agency applies decisions enacted by competent bodies of the Energy Community, according to ratified international contracts and is entitled to sign cooperation agreements with regulatory organizations of the Energy Community members in order to promote regulatory cooperation with other competent Energy Community member organizations and countries in the region in cross-border issues, to contribute to market integration, as well as harmonization and exchange of data and information at regional level.

According to the Law, the Agency's competences include: (a) providing energy undertakings with licenses for energy activities, (b) issuing guarantees of origin for electricity generated from renewable energy sources or high-efficient cogeneration, (c) setting the status of privileged generator of electricity from renewable energy sources, (d) approving or setting regulatory allowed revenue, prices and tariffs for energy undertakings, (e) making decision on appeals, (f) resolving disputes, (g) setting acts within its competences and giving consents to acts of energy undertakings, (h) supervising of operations of energy undertakings.

Crnogorski Elektroprenosni Sistem AD. (CGES), is the electricity transmission system operation of Montenegro and as such is responsible for the operation, maintenance and development of the transmission system in the territory of Montenegro and its connection with other systems. In addition, it is also responsible for ensuring the long-term capability of the system to meet requirements for electricity transmission in an economically justified manner, all with the aim of ensuring a stable operation of the electric power system and reliable electricity transmission from generation facilities to large consumers and to the distribution network [47].

COTEE, the Montenegrin Electricity Market Operator is responsible for creating conditions for enabling the competitiveness of the electricity market in Montenegro, to function in a public, non-discriminatory and

Figure 10.12 **Montenegro's electricity Market Scheme**



Source: Compiled by Energy community Secretariat

[47] http://www.cges.me/en/regulation/reports?download=250:operating-statement-for-the-year-2017

impartial manner, in accordance with the Law on Energy, Market Rules and International Standards and also to promote access to the market for all participants on equal terms. In accordance with the License for the activity of the Electricity Market Operator, COTEE concludes a participation contract with every electricity market participant and a balance-liability agreement and a financial settlement agreement with balance-responsible entities or holders of a balance-group's balance liabilities. One of COTEE's core activities is the promotion of power production from renewable energy sources and high-efficiency cogeneration in cooperation with the TSO, DSO, the Montenegrin government, privileged producers and electricity suppliers.

North Macedonia

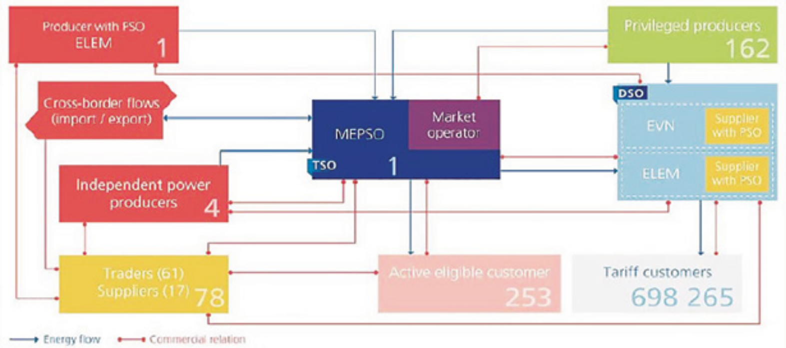
ERC[48] is the National Regulatory Authority. Its mandate stretches over the whole energy sector including electricity, natural gas, oil and oil derivatives, as well as the district heating sector. The ERC became operational in 2003, it is a member of Energy Community Regulatory Board and a member of the Energy Regulatory Regional Association, and is charged with the regulation of the energy sector including monitoring of the energy markets. Within the framework of its authority laid down in the Energy Law[49], ERC is independent in its operation and decision making. Moreover, the Energy Law of 2018 has significantly increased the powers of ERC according to the requirements of the TPEGM[50] with a number of competences including:

- monitoring of energy markets operation
- adoption of regulations, tariff systems and tariff setting methodologies for regulated energy activities;
- adoption of regulations, price-setting and tariff system methodologies on relevant energy type and/or energy fuel delivery to captive consumers;
- adoption of market rules, supply rules, as well as, rules for the purchase of electricity for the universal supplier;
- adoption of regulations on licenses, certification of energy transmission system operators and rules for acting upon complaints and resolving disputes;
- approval of the Grid Codes adopted by the energy system operators;
- approval of the terms and conditions as well as connection and access charges for relevant transmission and distribution systems;
- approval of the rules for balancing of electricity and natural gas transmission systems,
- approval of the rules for operation of an organised electricity market;
- approval of the maintenance plans and investment plans for the development of transmission and distribution systems prepared by the operators;
- approval of the compliance programmes adopted by the operators of the relevant energy systems;
- granting the status and keeping a Registry of Preferential Electricity Producers and a Registry of foreign traders and suppliers of electricity and natural gas that can perform energy activity in the country;
- proposal of measures aimed at encouraging competition in energy markets;
- stipulation and monitoring the implementation of obligations emerging from the energy activity licenses and more.

The Electricity Transmission System Operator of North Macedonia (MEPSO) is a joint stock company (JSC). It is fully state-owned, established in 2005 after the transformation of the vertically integrated Electric Power Company. MEPSO, a full member of ENTSO-E, owns the high voltage transmission grid, which includes 400 kV/110 kV substations, 110 kV/x kV substations, and 2,021 km of transmission lines and charges an electricity transmission fee set by the ERC based on its costs.
Currently, the three key functions of MEPSO are electricity transmission, power system operation and organization of the national electricity market. To perform its activities MEPSO was granted adequate licenses by the ERC until 2040.

48 http://www.erc.org.mk/
49 Energy Law, Official Gazette of the Republic of North Macedonia, No. 96/18., [Online]. Available only in local language: http://www.erc.org.mk/pages.aspx?id=8
50 Third Energy Package for Electricity and Gas Markets (TPEGM)

Figure 10.13 **North Macedonia's electricity Market Scheme**



Source: Energy community Secretariat

The **Electricity Market Operator (MO)** is an entity that organises operationally the electricity market in the Republic of North Macedonia. Currently, the MO is one of the branches of MEPSO[51] and has the obligations and authorizations to organise efficient operation and electricity market development in compliance with the principles of publicity, transparency, non-discrimination and competition, rendering of services being in its responsibility under the law and the conditions provided in the license. MO is also charged with(a) preparing and providing information to the power system operator necessary to draw up the dispatching timetable (b) maintaining records with regard to physical electricity transactions based on information about purchase transactions and electricity transit submitted by electricity market users, (c) preparing calculations with regard to electricity received, transmitted and delivered among electricity market participants including unbalances occurred between announced and realized transactions and calculations and submitting calculations to power system operator and (d) ensuring confidentiality about commercial and business data that the market participants are obliged to provide.

For the purpose of performing the energy activity of electricity market organisation and operation, the Energy Law[52] stipulates a legal unbundling of the MO from MEPSO. The main functions of the restructured MO include, (a) administration of the electricity market with bilateral agreements (b) calculation of the imbalances of the balance responsible parties and calculation of the cost of imbalances according to the measurement of electricity, the activated quantities of balancing services for each balancing service provider, the settlement price and the final daily schedule received from the electricity transmission system operator and the electricity distribution system operator, (c) the timely submission to the electricity transmission system operator of all information necessary for the preparation of the final daily schedules for the purchase and sale of electricity, (d) keeping records of all contracts for market participation concluded with the participants in the electricity market, (e) keeping records of all contracts for balance group creation concluded among the participants in the electricity market and the electricity market operator, (f) preparation of a daily market plan, (g) keeping a market participants registry, (h) concluding contracts for purchase and sale, as well as undertaking a balance responsibility for the generated electricity from preferential producers using a privileged tariff in accordance with this Law.

[51] http://www.mepso.com.mk/en-us/Details.aspx?categoryID=128
[52] Energy Law, Official Gazette of the Republic of North Macedonia, No. 96/18., [Online]. Available only in local language: http://www.erc.org.mk/pages.aspx?id=8
[53] https://www.elektrodistribucija.mk/About-us.aspx

Distribution System Operator (DSO) – Elektrodistribucija DOOEL[53] is the company that has power distribution on the territory of the Republic of North Macedonia as its primary activity. The company is organised into 19 Customer Centres[54] over the entire territory. Elektrodistribucija is part of the EVN Group[55]. The legal unbundling of Elektrodistribucija from its mother company EVN Macedonia[56] including rebranding was completed in 2018. As a DSO the main competences and goals of Elektrodistribucija are within the area of provision of a reliable and high-quality power supply to customers.

Distributon System Operator (DSO) – Energetika, is a subsidiary of the JSC ESM. It contains a vertically integrated DSO, which operates on the very limited territory of Skopje's industry complex Zelezarnica. Energetika serves a small number of light industrial and commercial customers and therefore it is not subject to the legal unbundling requirements of the TPEGM.

Serbia

In Serbia the electricity sector is regulated by Energy Agency, AERS, established by the Energy Law in 2005 as a regulatory body with competences covering electricity, natural gas, oil and oil product, and CHP heat energy sectors. More specifically AERS, which is a legal entity that is functionally independent of any state body, energy entity or user of its products and services, and of any other legal or physical entity, is the authority in charge of price regulations, licensing of energy entities to conduct energy activities, handling of appeals, energy market supervision and international activity implementation.

The electricity market in Serbia consists of (a) the bilateral electricity market; (b) balancing electricity market and (c) organized electricity market. Participants in the electricity market are the electricity producers, electricity suppliers, wholesale suppliers of electricity, the final customers, the transmission system operator, which is charged with providing system services, balancing the system, ensuring safe operation of the system and purchasing electricity for compensation of losses in the transmission system. Other participants include, the distribution system operator, who purchases electricity for compensation of losses in the distribution system, the operator of a closed distribution system of electricity and the market operator.

The Transmission System Operator of Serbia, EMS, manages the transmission system in order to facilitate: (a) the normal operation of the transmission system, (b) a reliable electricity delivery to transmission system users, (c) optimal use of available transmission capacities and (d) maximum level of efficiency in the whole transmission system operation. Together with the transmission system operators of Montenegro (CGES) and North Macedonia (MEPSO), EMS has established SMM control block (Serbia- North Macedonia-Montenegro) and acts as coordinator of the block, under the rules of operation in the Continental Europe interconnection and in order to reduce the expenses and achieve better quality of load-frequency control.

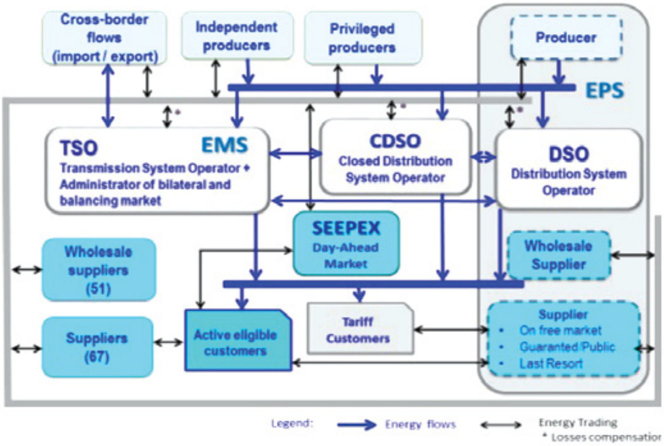
EMS's most important planning activities include; contracting ancillary services, preparation of outage plans, calculation of cross-border transmission capacities, preparation of power system operation plans, development of a model for system operation and security analysis. Entering into ancillary services agreements, TSOs provide power capacities for: (1) frequency regulation and power exchange (primary, secondary, tertiary), (2) voltage regulation and (3) system recovery after a blackout[57].

The organized Day-Ahead market in Serbia is run through SEEPEX JSC Belgrade[58], established in February 2016. It is the first

[54] https://www.elektrodistribucija.mk/About-us/Customer-Centers.aspx
[55] https://www.evn.at/Privatkunden.aspx
[56] https://www.evn.mk/
[57] Source: EMS; Available online at: https://www.ems.rs/page.php?kat_id=155
[58] www.seepex-spot.com

organised day-ahead electricity market/exchange in Serbia and in Southeastern Europe countries – Contracting Parties of the Energy Community. SEEPEX (South-eastern European power exchange) was established on the basis of partnership between EMS JSC and EPEX SPOT – France as a joint stock company with the majority ownership in the Serbian side, with the approval of competent state bodies. SEEPEX is a licensed Market Operator in an organised electricity market/ exchange, offering standardized products with delivery in the day ahead market. SEEPEX is planning on introducing intraday auctions within the Republic of Serbia and in the region of the southeastern Europe, in the near future.

Figure 10.14 **Serbia's electricity market scheme at the end of 2018**



Source: AERS

Turkey

The **Energy Market Regulatory Authority (EMRA)** is Turkey's regulatory authority, an inter-institutional non-profit organization with main purpose to promote energy regulatory changes in Turkey and the wider Eurasia and Africa area. Member regulators exert substantial ownership of EMRA organizing its operation to be demand driven and responsive to its members' needs. EMRA is responsible for regulating and monitoring the electricity market of Turkey including (a) preparation of secondary legislation, (b) issuing licenses for energy activities, (c) monitoring market performance and ensuring the enforcement of market rules, (d) setting out annual customer eligibility limit and regulated tariffs, (e) drafting, amending enforcing and auditing standards, distribution and customer services codes, (f) taking necessary measures for supporting domestic and renewable energy sources and more[59].

The state-owned **Turkish Electricity Transmission Company (TEİAŞ)**, under the supervision of EMRA, has a monopoly over transmission activities (and is unbundled from generation activities). In this capacity, TEİAŞ operates the real-time, balancing and ancillary services markets. Turkey's electricity distribution is carried out by 21 DSOs which constitute regional monopolies. After completing the process of privatisation in 2013, all 21 distribution licenses were handed over to private companies, under the supervision of EMRA. However, distribution infrastructure remains under the ownership of state-owned Turkish Electricity Distribution Company (TEDAŞ). Unbundling requirements under the 2013 Electricity Market Law prohibit distribution companies from participating in other activities in the electricity supply chain. As such, distribution activities are separated from retail activities, which are conducted by "authorised suppliers" [60].

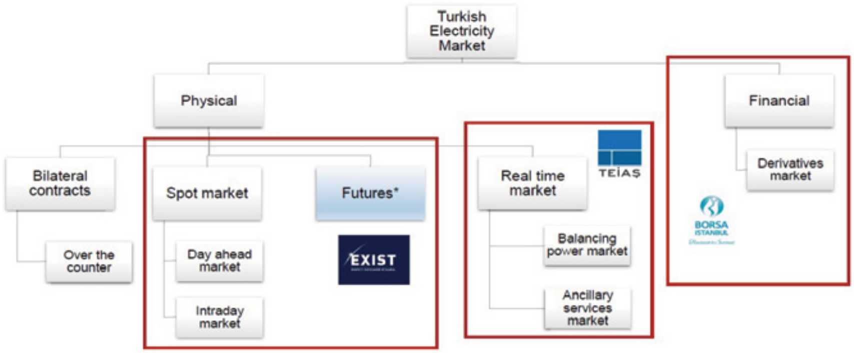
[59] https://pubs.naruc.org/pub.cfm?id=537AE42E-2354-D714-5188-1620C114E3B2
[60] https://www.iea.org/reports/turkey-2021

The Turkish electricity wholesale market mostly relies on bilateral contracts, complemented by a spot market and a balancing mechanism. As part of the transition to a liberal and competitive energy market model, day-ahead, intraday and balancing power markets were established to provide market participants a trading platform based on integrity, transparency and competition. Moreover, a physically settled power futures market was planned to start operating in December 2020.

The **Energy Exchange Istanbul (EXIST)** operates the day-ahead and intraday electricity spot market. EXIST was officially established in March 2015 as part of the 2013 Electricity Market Law No. 6446 and the 2011 Turkish Trade Law No. 6102. EXIST's main activities include planning, establishing, developing and operating energy markets, which are stated in the market operation license, in an efficient, transparent and reliable manner.

EXIST is positioned to secure reliable reference price determination without discrimination among providers. TEİAŞ and the Istanbul Stock Exchange hold 30% shares each in EXIST, with private market participants holding the remaining 40%.

Figure 10.15 **Turkey's electricity market operation scheme**



Source: IEA

The Regional Security Coordinators and SELENECC in Thessaloniki

The transmission systems in Europe started to get interconnected during the '50s; till then, the need to cooperate between them became an obvious necessity, so that they could maintain the safety and the continuity of electricity for all consumers. In the following years, structures were set up on a voluntary basis for this purpose (e.g. UCTE in Europe, NORDEL in Scandinavia, etc.) which strengthened and promoted cooperation, especially at the technical level, with excellent results: the European network, although extremely extensive, presents excellent reliability. The European transmission systems are highly interdependent due to the high interconnectivity among them. During the last years, the operation of power systems is more complex due to the continuous and fast changes in the operational conditions (in some cases even extreme), posing new technical challenges in terms of operational security. The power flow in the grid is fluctuating resulting in numerous and abrupt changes. This is due to the fluctuation of the power produced by RES but also to the large increase in commercial electricity exchanges (especially after the liberalization of the markets).

The experience of day-to-day operation and the analysis of some major disruptions that have occurred in European networks in the recent decades have demonstrated the need for closer regional cooperation on security issues. Since 2008, 6 Regional Security Coordinators (RSCs) have been developed in Europe, with the mission of better coordinating the operation of neighboring systems. Therefore, in the European territory the following RSCs are in operation: TSCNET serving the Central and Northeastern Europe, CORESO serving the Central and North Europe, the Nordic RSC serving the Nordic countries, the Baltic RSC for the Baltic countries, the Belgrade-based SCC which provides services to Operators in South East Europe and the 6th RSC, SeleNe CC which is covering the EU countries in SE Europe. SeleNe CC established in May 2020 and it is located in Thessaloniki.

The RSCs are companies established by Transmission System Operators (TSOs) with a mission to coordinate and assist Operators in security matters on a daily basis, providing the following services:

1. Development of a common grid model
2. Operational Security Coordination
3. Coordinated Capacity Calculation
4. Coordination of maintenance planning
5. Evaluation of Short-Term and Medium-Term Adequacy of the regional production-transmission system while new services are gradually being added.

The role of the RSC is advisory; it issues recommendations to the TSOs but the final decisions and responsibility belong to TSOs.

RSC Thessaloniki - Southeast Electricity Network (SEleNe-CC)

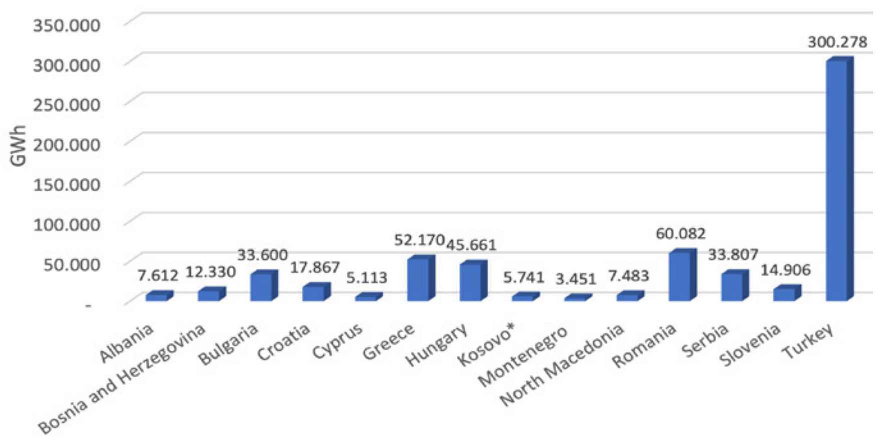
In May 2020, the TSOs of Bulgaria (ESO-EAD), Greece (IPTO), Italy (Terna) and Romania (Transelectrica, RS) established an RSC under the name Southeast Electricity Network - Coordination Center SEleNe-CC) which is equally shared between the Operators. The new established RSC is sited in Thessaloniki. SELENE CC is initially supported by 15 employees and from 1st of July 2021 will provide all the aforementioned services to its TSOs-shareholders. At this stage, the installation of the necessary infrastructure is being completed and extensive simulation tests (dry runs) are performed using real data.

The operation of SEleNe is expected to improve the security of networks in South East Europe, to contribute to the exchange of know-how between the staff of the TSOs in the region in dealing with new technical challenges and to promote the harmonization of non-EU balkan countries with the European institutional framework. As envisaged by the Clean Energy Package (CEP), from July 2022 the RSCs (and SEleNe) will be transformed into "Regional Coordination Centers" (RCCs); RCCs will replace RSCs in their current mission while new (much more) responsibilities are also to be assigned to them.

10.4 Electricity Demand

Electricity demand across SE Europe is varied and reflects population characteristics, GDP structure and commercial industrial activities. Since the region is comprised by economies of various sizes and diverse economic activity with respect to electricity intensity, electricity demand is extremely diversified. In that respect, there are large markets like Turkey, the region's largest consumer, where gross electricity consumption was approximately half of the total regional gross electricity demand in 2019, while there are very small consumers like Montenegro which exhibited approximately 1.15% of Turkey's electricity demand in 2019 and stood as the smallest electricity consuming market in SEE. This situation is demonstrated in Figure 10.16, which shows the gross electricity consumption of the countries in the broader region of SE Europe for 2019.

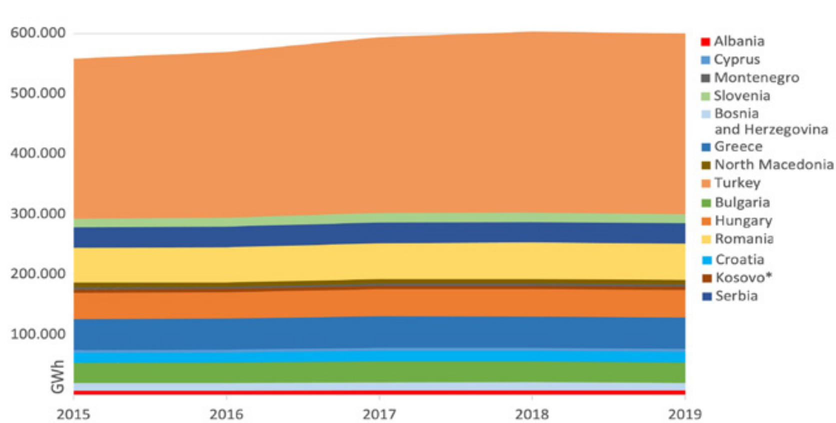
Figure 10.16 **Gross Electricity Consumption in SE Europe for 2019 (GWh)**



Source: IENE (based on data by Energy Community, Entso-e, TEIAS, IPTO, CERA, MAVIR, AERS, EWRC, SURS)[61]
Note: Electricity Consumption from Israel and Greece's NIIs is not depicted

The total electricity demand of the region, including Turkey, stood at 600.1 TWh[62] in 2019, decreased by 0.5% in comparison to 2018, with this slight variation being primarily attributed to weather driven demand fluctuation across the region. More specifically the southern part of the region, namely Cyprus, Greece, North Macedonia and Kosovo* saw slight year-to-year electricity demand increases in 2019, with Turkey's electricity demand remaining stable at ~300.2 GWh annually. In a broader perspective, electricity demand has increased rapidly in SE Europe, in recent years, with regional gross electricity demand rising by approximately 7.48% since 2015 driven primarily by Turkey, which has seen significant population growth in the past years[63]. It is notable that excluding Turkey, the region has seen only a 2.46% gross electricity demand increase since 2015.

Figure 10.17 **Gross Electricity Consumption for SE Europe for the period 2015 - 2019 (GWh)**



Source: IENE (based on data by Energy Community, Entso-e, ERE, TEIAS, IPTO, CERA, MAVIR, AERS, EWRC, SURS)[64]
Note: Electricity Consumption from Israel and Greece's NIIs is not depicted

61 * Kosovo is presented separately without prejudice to positions on status and in line with the United Nations Security Council Resolution 1244 (1999)
62 Not including consumption occurring in Israel and the Greece's non interconnected islands
63 https://openknowledge.worldbank.org/bitstream/handle/10986/34318/Turkey-Economic-Monitor-Adjusting-the-Sails.pdf?sequence=6&isAllowed=y
64 * Kosovo is presented separately without prejudice to positions on status and in line with the United Nations Security Council Resolution 1244 (1999)

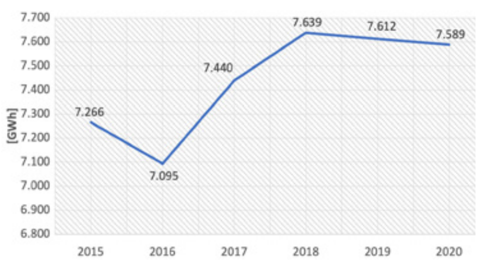
Regional Market Characteristics

A country-by-country analysis of electricity consumption patterns follows:

Albania's electricity consumption is partially affected by the local hydrological cycle as transmission losses are proportional to the output of domestic hydropower as well as to the volume of transmitted electricity[65]. Electricity demand has grown notably during the period 2015-2018 by 5.14% on an annual basis. However, demand has remained relatively stable ever since, with consumption receding marginally in 2019 and 2020 by 0.35% and 0.31% respectively, currently (2020) standing 4.55% higher than it was on 2015.

This can be attributed partly to the low precipitation, which led to significantly reduced hydropower output and therefore to lower demand required to cover technical losses of the Albanian system, which balanced out the increase in demand from consumers in 2019. In the period 2017 – 2019 we see a constant increase in the number of consumers by approximately 1.5% annually, while the rate of year-to-year increase of non-household consumers increased as illustrated in Table 10.2, i.e is higher than 2.4% for the same period annually with the highest increase in the number of consumers recorded in 2018 at 3.54% in comparison to 2017. Furthermore, in 2020 in the aftermath of suppressed economic activity due to Covid-19 pandemic, demand receded slightly.

Figure 10.18 **Gross Electricity Consumption in Albania over 2015-2019 (GWh)**



Source: ERE

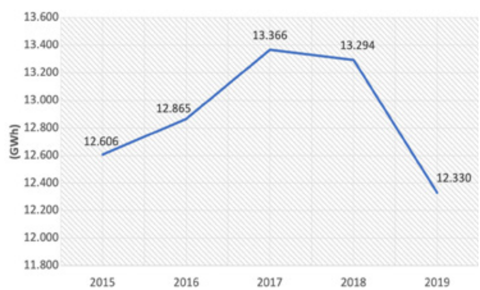
Table 10.2 **Number of Electricity Consumers in Albania over 2015-2019**

	2015	2016	2017	2018	2019
Electricity customers / total	1,244,716	1,189,478	1,209,958	1,228,016	1,249,882
Electricity customers / non-households	164,653	160,484	164,433	170,248	175,212
Total Electricity customers - y-y increase [%]		-4.44%	1.72%	1.49%	1.78%
Electricity customers / non-households y-y increase [%]		-2.53%	2.46%	3.54%	2.92%

Source: Energy Community

In **Bosnia and Herzegovina**, gross electricity demand receded in 2019 after peaking in 2017 and 2018 at 13,366 GWh and 13,294 GWh respectively following a continuous increase since the beginning of the decade. Electricity demand fell in 2019 sharply, at 12,330 GWh, having decreased by 7.25% in comparison to 2018, falling 2.19% lower than it was in 2015. The main reason was the sharp decline of electricity consumption from non-household consumers which fell to 6,234 GWh, lower by 12.29% and 3.45% than it was in 2018 and 2015 respectively[66]. This came as a result of the closure in July 2019 of a major aluminium producer (Aluminij Mostar), with electricity demand in the country declining significantly as of the second half of 2019[67].

Figure 10.19 **Gross Electricity Consumption in Bosnia and Herzegovina over 2015-2019 (GWh)**

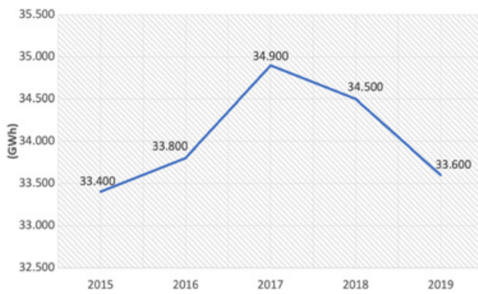


Source: Energy Community

[65] https://ere.gov.al/doc/ERE_annual_report_2019_26102020.pdf
[66] https://energy-community.org/regionalinitiatives/infrastructure/donors/Regional/REEP.html
[67] https://www.e3analytics.eu/wp-content/uploads/2020/11/E3A_Country-Report_BIH.pdf

In **Bulgaria** gross electricity consumption over the last 5 years, i.e. 2015-2019 peaked in 2017 at 34.9 TWh. Since then, it recorded consecutive declines, falling to 33.6 TWh in 2019, marginally (+0.6%) higher than it was in 2015.

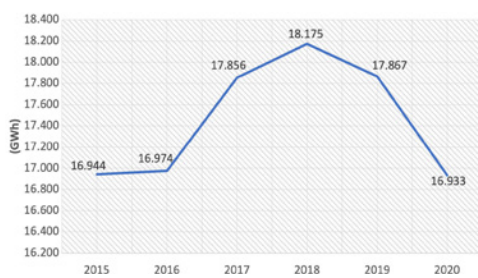
Figure 10.20 **Gross Electricity Consumption in Bulgaria over 2015-2019 (GWh)**



Source: EWRC

In **Croatia** gross electricity demand during the period 2015-2020 peaked in 2018 at 18,175 GWh, 7.26% higher than in 2015 according to data by Entso-e. From 2018 onwards, Croatia has seen a decline in electricity consumption by 1.69% in 2019 (y-y) and 5.22% in 2020, falling marginally below the domestic gross electricity demand recorded in 2015 as a result of constrained economic activity in order to mitigate the spread of covid-19 virus.

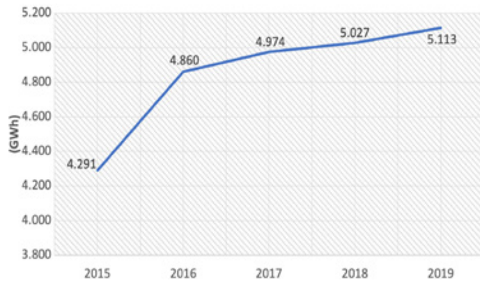
Figure 10.21 **Gross Electricity Consumption in Croatia over 2015-2019 (GWh)**



Source: Entso-e

Cyprus has seen an increase of gross electricity demand for the last 5 years, which in 2019 stood at 5,113 GWh, 19.16% higher than it was in 2015.

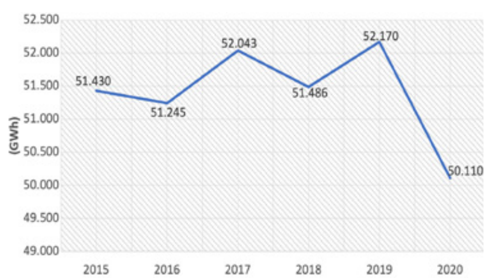
Figure 10.22 **Gross Electricity Consumption in Cyprus over 2015-2019 (GWh)**



Source: CERA

Electricity consumption in the **Greek** interconnected system rose gradually until 2019 partially due to Greece's GDP recovery from Q1 of 2017 onwards, which helped gross electricity demand consolidate above 52 TWh in 2017 and 2019, with a decline at 51.49 TWhs in 2018 primarily due to a mild winter. Overall, in the domestic electricity market for the interconnected system, the final consumption including network losses was 52,170 GWh in 2019 followed by a sharp decline at 50,110 GWh in 2020 (-3.95% y-y) due to restricted economic activity as a result of the measures imposed for the mitigation of Covid-19 spread. Figure 10.23 presents the evolution of gross electricity consumption in Greece, excluding the non-interconnected islands, over the last 6 years.

Figure 10.23 **Gross Electricity Consumption in Greece[68] over 2015-2020 (GWh)[69]**



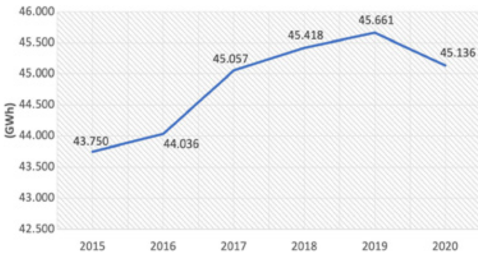
Source: IPTO

[68] In Greece's interconnected system

[69] Does not include electricity demand in non-interconnected islands (NIIs)

Electricity demand in **Hungary** has been rising over the past 5 years until 2019, with the annual rate of increase retreating gradually, falling at 0.53% in 2019. 2019 was also the year that Hungary recorded its highest annual electricity consumption over the past 6 years, with demand receding slightly in 2020 to 45,136 GWh, 1.15% lower than it was in 2019. However, gross electricity demand remained higher by 4.37% than it was in 2015.

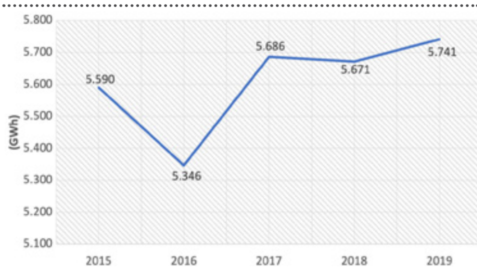
Figure 10.24 **Gross Electricity Consumption in Hungary over 2015-2020 (GWh)**



Source: MAVIR

Moreover, according to data published by MAVIR, Hungary's TSO, the electricity consumption of end users (net consumption) has increased by 0.56% in 2019, reaching 40.8 TWh[70]. The consumers made 65.74% of their electricity purchases on the electricity market and made 28.83% of such purchases as users eligible for the universal service. According to MAVIR's report, sectors that presented an increase in electricity consumption in 2019 include the agricultural, construction, transportation and the services sector, with domestic household consumption exhibiting also a significant increase[71].

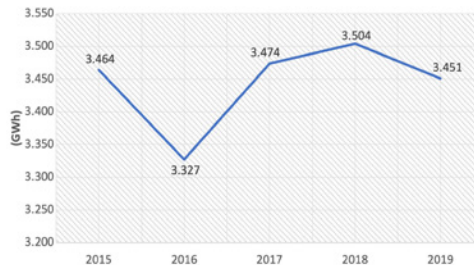
Figure 10.25 **Gross Electricity Consumption in Kosovo over 2015-2019 (GWh)**



Source: Energy Community

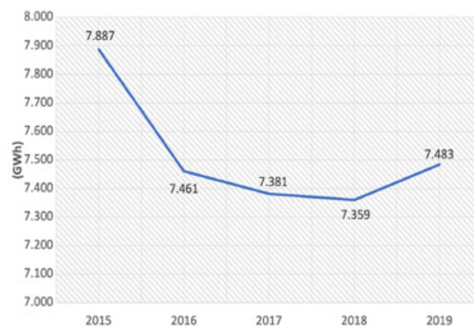
Electricity demand has remained relatively stable in **Kosovo** over the period of 2015 – 2019 with a small decline by 3.9% in 2016 due to a mild winter. Moreover, consumption has fallen in **North Macedonia** in 2016 by 5.4% y-y and remained relatively stable ever since rising slightly in 2019 at 7.48 TWh annually.

Figure 10.26 **Gross Electricity Consumption in Montenegro over 2015-2019 (GWh)**



Source: Energy Community

Figure 10.27 **Gross Electricity Consumption in North Macedonia over 2015-2019 (GWh)**



Source: Energy Community

Romania's electricity demand has been growing steadily over the period 2015-2019 following the rising economic activity of the country as its continuous increasing GDP implies. It is notablethat Romania has seen a GDP growth by more than 41% over the specific period that drove among others electricity consumption to higher levels. In contrast, 2020 brought a significant drop of electricity consumption in Romania, which fell by more than 5.4% on an annual level affected by the limited activity due to covid-19 pandemic.

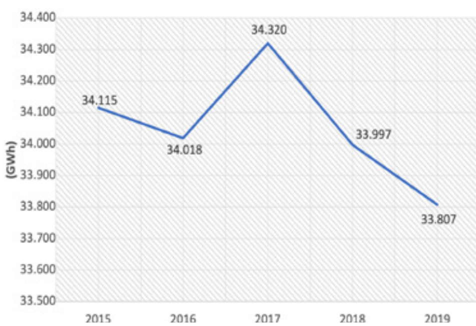
[70] Excluding transmission, distribution and other technical losses.
[71] http://www.mekh.hu/download/8/35/e0000/a_magyar_villamosenergia_rendszer_2019_evi_adatai.pdf

Serbia on the other hand, has seen its domestic electricity consumption peaking in 2017 at 34.32 TWh and declining marginally ever since, falling to 33.81 TWh in 2019, 1.5% lower than its peak in 2017. This can be attributed to the milder winters of 2018 and 2019 as compared to 2017, which brought total electricity demand slightly lower during the aforementioned years despite registered economic growth.

Figure 10.28 **Gross Electricity Consumption in Romania over 2015-2020 (GWh)**

Source: Transelectrica

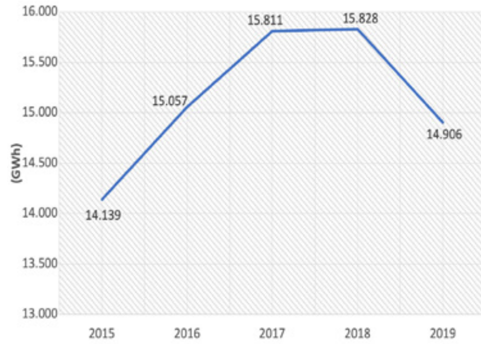
Figure 10.29 **Gross Electricity Consumption in Serbia over 2015-2019 (GWh)**



Source: AERS

Electricity demand peaked at 15.83 TWh in **Slovenia** in 2018 remaining relatively stable on an annual level compared to 2017. Most notably, electricity demand increased by 11.83% in two years, in the period 2015-2017 following a GDP increase of 12.76% (or ~$5.5 bil.) over the same period. Similar to the rest of the SEE, in 2020 electricity consumption in Slovenia shrunk, driven by throttled economic activity due to Covid-19 pandemic.

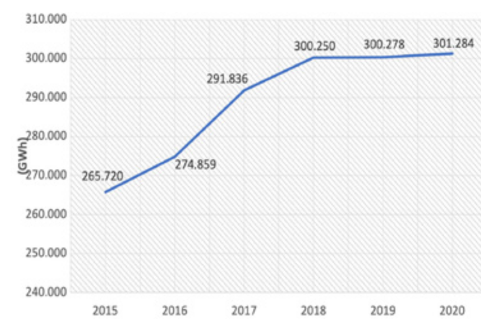
Figure 10.30 **Gross Electricity Consumption in Slovenia over 2015-2019 (GWh)**



Source: SURS

Electricity consumption in **Turkey** has been steadily increasing until 2018, when it reached 300.25 TWh, 13% higher than in 2015, but then the increase slowed down with only marginal consumption increases until 2020. It is notable that Turkey is the only country in the region, that its electricity demand did not recede on an annual basis as a result of constrained economic activity due to the Covid-19 pandemic, even though its overall economic activity during the same year shrunk.

Figure 10.31 **Gross Electricity Consumption in Turkey over 2015-2020 (GWh)**

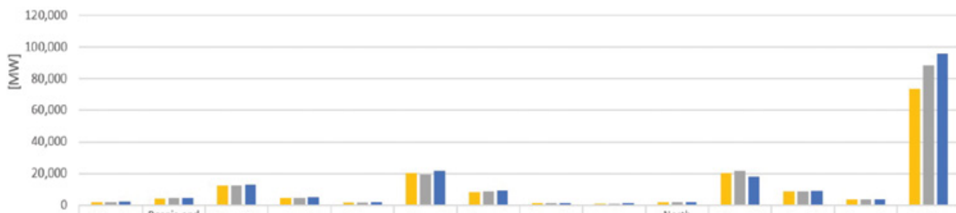


Source: TEIAS

10.5 Electricity Supply

During the past decade, significant new generation capacities have been integrated in the SE European grid. Overall power generating units in SEE accounted for a combined installed capacity from all sources of 189.07 GW in 2020, 15.4% higher than in 2015. As we can see in Figure 10.32, the largest volume of power generating capacity has been introduced in Turkey, which in 2020 saw its domestically installed power generating units increasing in capacity by 30.4% in comparison to 2015, standing at 95.71 GW. Moreover, notable addition of new power generating capacity has been respectively made in Hungary and Greece, with most new capacity being renewables, i.e. solar PV and biofuel power stations in Hungary and wind and solar PV farms in Greece. Most countries in the region have made steps forward towards the adoption of RES, but some have stagnated towards this goal as of late. Bulgaria is one of them, progressing slowly in new RES capacity integration with only approximately 43 MW of solar PV and 13 MW of small hydropower units introduced in the period 2015-2020.

Figure 10.32 **Installed capacity evolution for power generation in SEE**



	Albania	Bosnia and Herzegovina	Bulgaria	Croatia	Cyprus	Greece	Hungary	Kosovo*	Montenegro	North Macedonia	Romania	Serbia	Slovenia	Turkey
2015	1962	4107	12710	4631	1721	20273	8217	1011	862	2031	20557	8483	3921	73386
2018	2205	4462	12501	4840	1768	19347	8503	1076	944	2077	21616	8757	3699	88463
2020	2496	4531	12783	5091	1853	21599	9500	1099	977	2088	18271	9094	3979	95709

■2015 ■2018 ■2020

Source: IENE from data derived from ENTSO-e, ERE, CERA, IPTO, HEDNO, Transelectrica, MAVIR, TEIAS, ERC, ESO, Energy Agency of Slovenia

In 2020, 29.79% of the regional power generating capacity was hydropower, 23.79% was solid fuels, i.e. coal, lignite etc., 3.17% was nuclear power plants, 21.5% gas-fired units, 2.78% oil-fired units, 9.69% wind farms 0.97% biomass/biofuel-fired units, 7.25% solar PV, 0.85% geothermal plants and 0.2% waste incineration plants. Overall, RES corresponded to 18.76% of the total installed power generation capacity of the region. RES integration is still developing, as there is untapped potential for new cost-efficient projects across the region with emphasis on the Western Balkan region, which has entered the clean energy transition race as of late. Even though the transition towards higher integration of RES has been moderate in comparison to the rest of Europe, in the period 2015-2020, SEE has seen significant increases in newly installed capacity of solar PV and wind turbines, as these technologies have also experienced a significant drop in their production and installation costs. Consequently, the solar PV and wind farms in SEE increased in capacity by 172.8% and 62% over the period 2015-2020, with the integration of new solar PV substantially increasing from 2017 onwards, when it recorded its greatest y-y increase of 35%. 2019 and 2020 have been very significant years for the windpower industry in SEE, presenting year-to-year increases in installed capacity by more than 11% each, i.e. approximately 1.7 – 1.8 GWh of newly integrated wind capacity each year respectively.

Overall, we note a significant effort in reducing the use of expensive and carbon intensive oil units, mostly evident in Greece and Turkey where the development of renewables, and hydro in the case of Turkey, has reduced the need of oil consumption for power generation purposes. On the other hand, concerns for security of supply driven by notable electricity demand increases in the early 2017 have pushed for new oil-fired capacities in Slovenia, Hungary and Bosnia and Herzegovina. Overall, installed capacity of oil generating units in SEE has fallen by 13% over the period 2015-2020, currently standing at 5.26 GW total. On the other hand, a small increase in the deployment of natural gas has been observed, which stems from choices that considered gas as a competitive alternative to coal and as a "transition fuel". Such choices of investment in new gas-fired power generating units were made mostly by Turkey and Bulgaria and to a lesser extent by Slovenia and Serbia.

This increase of installed gas-fired generating capacity was almost balanced out on a regional level by retirements and mothballing of existing old gas-fired power stations, mostly located in Romania, Hungary and Greece due to end-of-life; in the majority of cases those consisted of less efficient steam turbine units. Overall, gas-fired power capacities exhibited a marginal increase in the region, rising 1.2% over the period 2015-2020. Solid fuel power stations have also increased in installed capacity in the region as a result of activity in Turkey, which is the only regional market that has realized investments in coal capacities during the period 2015-2020.

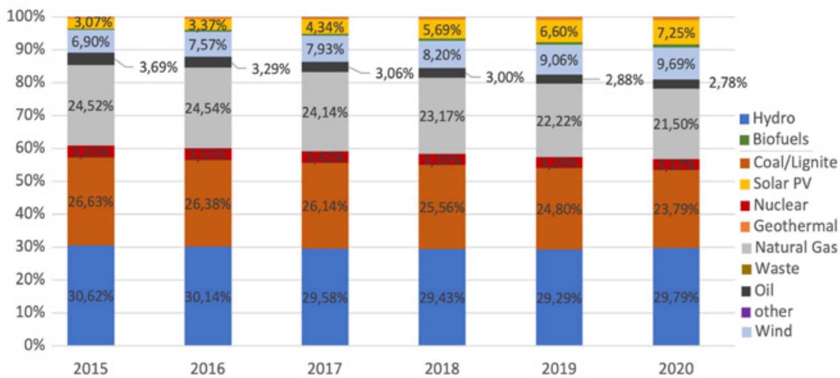
Various other coal and lignite capacities are under construction or have been under consideration in the region, but none have been commissioned in the period 2015-2020 outside Turkey.

As a result, coal-fired power generation capacity in SEE stood at 44.98 GW in 2020, which is 3.1% higher than 2015. Similarly, nuclear capacity of SEE has remained unchanged throughout the period 2015-2020 at 6 GW, numbering 4 power stations, which include Paks in Hungary, Cernavoda in Romania, Krsko[72] in Slovenia and Kozloduy in Bulgaria.

Geothermal capacities have been deployed at a large scale in Turkey, where almost 100% of the active installed geothermal power plant capacity of the SEE region is located, accounting for 1.6 GW in 2020. As a matter of fact, the capacity of the Turkish geothermal generation was more than doubled (+154%) over the period 2015-2020. Significant new capacities of biomass plants (including all biofuels) have also been introduced in SEE's power system with their total installed capacity standing at 1.84 GW in 2020, risen by 153% compared to 2015.

Major regional investors in biomass are Turkey, Hungary and Croatia, while new biomass power plants have also been integrated in Greece and Bosnia and Herzegovina.

Figure 10.33 **Installed capacity evolution in SEE per source in [%] of the total regional install capacity**

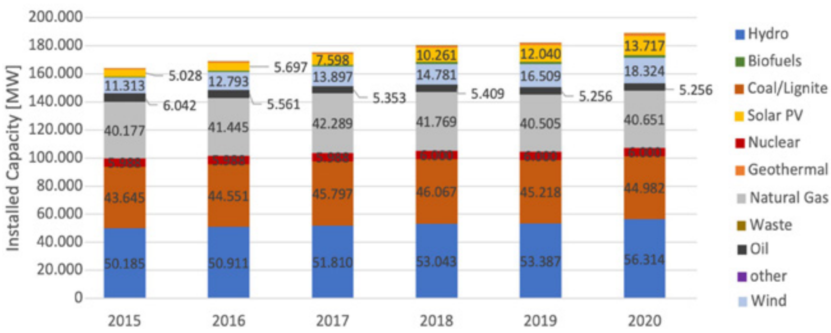


Source: IENE from data derived from ENTSO-e, ERE, CERA, IPTO, HEDNO, Transelectrica, MAVIR, TEIAS, ERC, ESO, Energy Agency of Slovenia

[72] Krsko is jointly owned by Slovenia and Croatia, but the analysis has geographical characteristics and considers it to be solely part of the Slovenian power system.

10

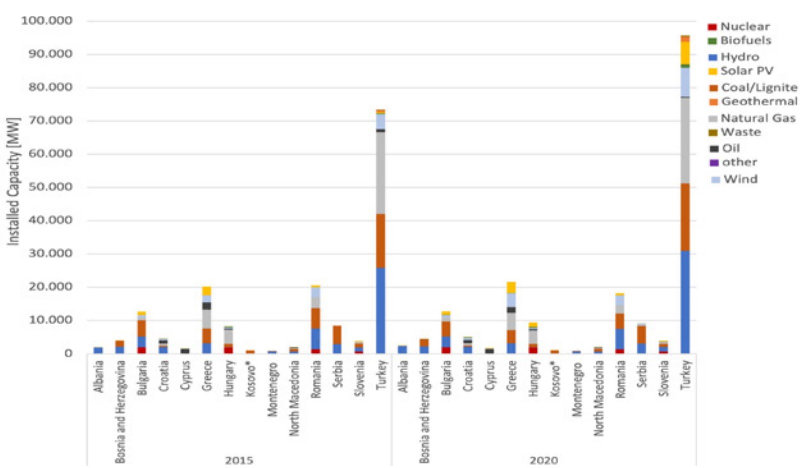
Figure 10.34 **Total installed capacity evolution in SEE in [MW] per source**



Source: IENE from data derived from ENTSO-e, ERE, CERA, IPTO, HEDNO, Transelectrica, MAVIR, TEIAS, ERC, ESO, Energy Agency of Slovenia

In Figure 10.35 we observe the development of installed capacity for power generation in SEE per country. Overall, the region has heavily invested in coal and hydro. Most of the regional coal/lignite-fired power generating capacity is located in Turkey, Greece, Bulgaria, Serbia and Romania. Significant hydropower capacities are installed in all countries of the region, except Kosovo and Hungary. Moreover, most of regional gas-fired power capacity is located in Turkey, Greece, Hungary and Romania. The only countries that still utilize large-scale oil-fired power stations are Cyprus and Greece as a result of scarce indigenous sources in their island systems. This is expected to change (a) with the construction of the FSRU in Cyprus, which is expected to be in operation by 2022 and will introduce natural gas to the electricity mix of the island , and (b) by the interconnection of Greek islands to the mainland system currently being implemented. Regarding RES, the majority of solar PV capacity in SEE, approximately 72.4% is located in Turkey and Greece, with significant capacities also installed in Hungary, Bulgaria and Romania. Moreover, most windfarms in the region are located in Turkey, Greece and Romania, which in 2020 accounted for 86.3% of the total windpower capacity installed in the region. Regarding biomass capacity, this is located mostly in Hungary, Croatia and Turkey, where 84.3% of the total biomass power generation capacity is located, with notable capacities located also in Bulgaria and Greece.

Figure 10.35 **Decomposition of installed power generating capacity per country in SEE for 2015 and 2020**

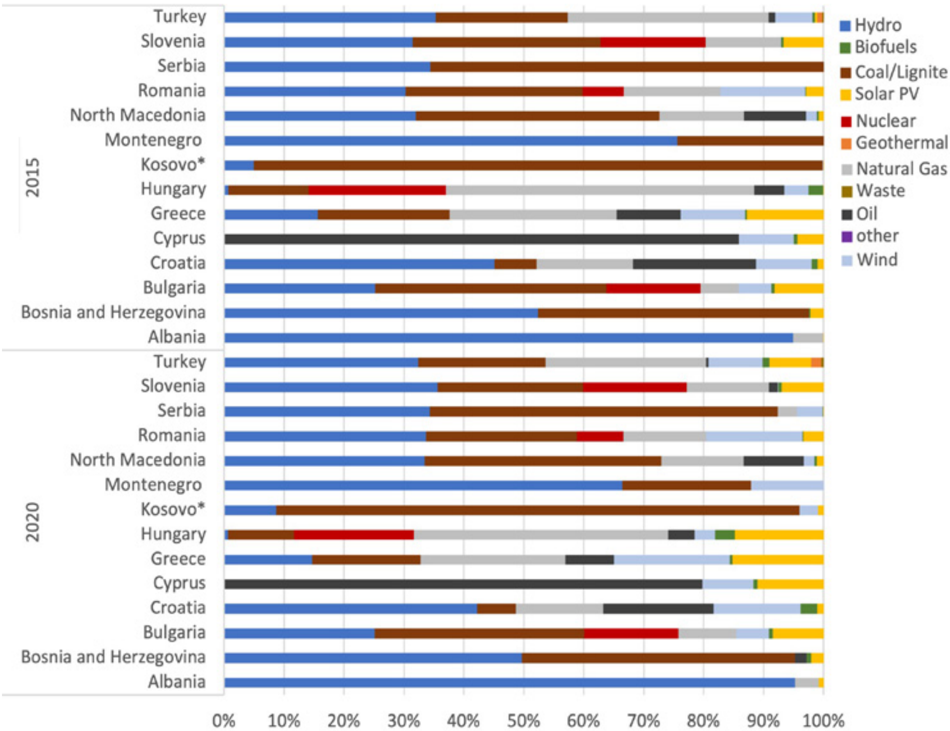


Source: IENE from data derived from ENTSO-e, ERE, CERA, IPTO, HEDNO, Transelectrica, MAVIR, TEIAS, ERC, ESO

[73] https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/071020-cyprus-enters-lng-era-with-fsru-groundbreaking-at-vassilikos

[74] https://www.admie.gr/sites/default/files/users/dssas/DPA%202021-2030/dpa2021-2030.pdf

Figure 10.36 **Development of installed capacity profiles in SEE countries shown for 2015 and 2020**



Source: IENE from data derived from ENTSO-e, ERE, CERA, IPTO, HEDNO, Transelectrica, MAVIR, TEIAS, ERC, ESO, Energy Agency of Slovenia

The gradually increasing electricity demand in the region of SE Europe has driven regional generation higher. More specifically, the power generated in SEE has exceeded 600 TWh annually for the first time in 2017 and peaked at 615.5 TWh in 2018, receding to 600 TWh in 2019. In 2019, 35.60% of the total electricity generated in the region, i.e. 213.74 TWh came from solid fuels, mostly lignite and coal.

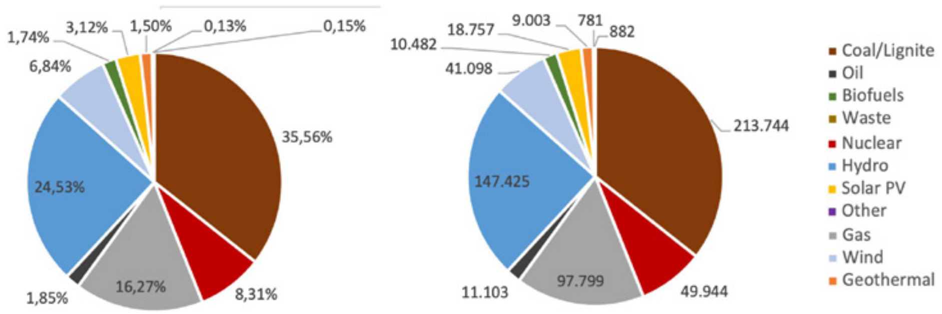
Additionally, 24.56% of regional power generation was generated by hydropower plants, which corresponds to 147.42 TWh, and 16.18% by natural gas-fired power plants which accounts for 97.17 TWh. The share of nuclear in the regional power generation mix was 8.32%, corresponding to 49.94 TWh, while oil-fired generation's share has fallen to 1.85%, i.e. 11.1 TWh.

Regarding RES's share in the regional generation mix in 2019, excluding small hydro[75], this rose to 13.21%, corresponding to 79.32 TWh, from 7.76% in 2015. The detailed analysis of RES's contribution to the regional power generation mix shows that a total of 41.1 TWh or 6.85% of the regional generation mix came from wind, 18.73 TWh or 3.12% was provided by solar PV, 10.48 TWh or 1.75% was produced in biofuel-fired power stations and 9 TWh or 1.5% of the regional generation was the output from geothermal powerplants.

Furthermore, waste incineration plants generated 0.78 TWh which accounts for 0.13% of the total volume of electricity produced regionally, while other sources contributed 0.88 TWh or 0.15% of the regional generation mix.

[75] Small hydropower plants are included in the hydropower segment.

Figure 10.37 **Power generation mix in SE Europe in 2019 (a) in [%], [b] in [GWh]**



Source: IENE/IEA

The development of regional power generation was not only driven by changes in available capacities but was also heavily influenced by the hydrological cycle of the region and the development of natural gas prices. Therefore, we observe a dip in regional hydropower generation in 2017 as a result of a very dry period between Q3 2016 – Q2 2017, with the hydropower output of the region falling by 18.9% in comparison to 2016. The hydropower yield reduction in the specific year was replaced by natural gas-fired generation. As a result, power generation from gas rose in 2017 by 22.13% in comparison to 2016. Hydropower generation recovered in 2018 and further increased in 2019 despite the drought phenomena affecting the Balkan region in the first semester of 2019[76].

This can be attributed to the new hydropower capacities added in the region, especially in Turkey, which were able to offset hydropower generation decline on a yearly basis.

Moreover, even though power generated by solid fuels increased slightly over the period 2015-2019, we observe a decline in EU member states, primarily as a result of available capacity decline, as older plants were decommissioned or mothballed and part of the generation was gradually replaced by renewables. A decommissioning phase of coal plants at a regional scale for EU member states was primarily initiated as part of obligations towards the European regulation, most notably the emission limitations set by IED (EC Directive 2010/75/EU[77]) and its amendments. The highest decline of power output from solid fuels in SEE over the period of 2015-2019 has been observed in Greece, where the output of domestic lignite-fired power plants was halved, down by 51.12% in 2019 in comparison to 2015. The decline was gradual, reflecting market conditions for lignite-fired generation, as variable costs of specific units soared following the integration of carbon emissions costs from 2018 onwards.

This became more evident in 2019 when the annual average carbon emission allowance prices rose in the European ETS to 24.89 €/ton CO_2 eq., 55.2% higher than it was in 2018 (16.03 €/ton CO_2 eq.). A lower, but significant decline in coal-fired generation has been observed in the other EU member states, namely Bulgaria, Croatia, Hungary and Romania, with generation from solid fuel declining over the period 2015-2019 by 23.4%, 28.8%, 29.2% and 22.3% respectively. It is important to note that 4 countries in the region, namely Bulgaria, Hungary, Romania and Cyprus opted to receive free emission allowances for electricity generators during the third ETS trading period, 2013-2019, according to Article 10(c) of the ETS Directive, in order for eligible Member States to be allowed to modernise their energy sector[78].

[76] JRC, 2019, "Annual Progress Report of the European and Global Drought Observatories, 2019" Available online at: https://ec.europa.eu/jrc/en/publication/annual-progress-report-european-and-global-drought-observatories

[77] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32010L0075&from=EN

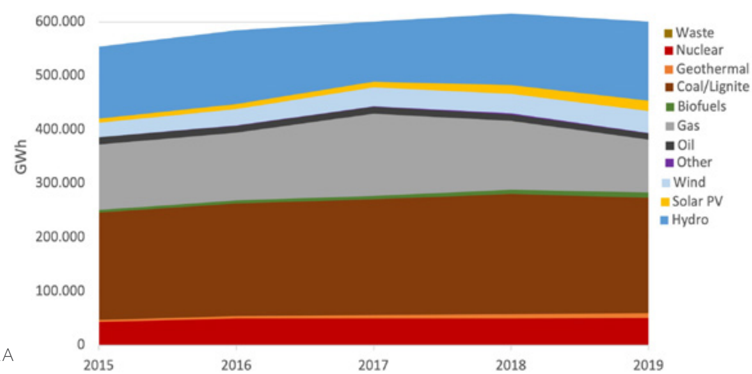
[78] https://ec.europa.eu/clima/policies/ets/allowances/electricity_en

This move helped avoid exposure to ETS emission prices for the incumbent generators in these 4 countries, and as a result affected positively the market competitiveness of some of their most carbon intensive generators over the specific period. As a result, the decline of the annual output of carbon intensive power plants over time was limited, as shown in the comparison between the output decline from coal-fired generators in the countries that received derogation from ETS and Greece that did not. Moreover, this trend is anticipated to continue in the future as Bulgaria, Hungary and Romania opted to continue receiving free emission allowances during the fourth ETS trading phase in 2021-2030[79]. Overall, actual power output from solid fuel generators rose in SEE by 7.1% over the period 2015-2019 as a result of major investments in the coal industry in Turkey, which led to an increased output of domestic coal-fired generation in 2019 of 113.2 TWh, higher by 48.65% than the levels seen in 2015.

Slightly higher power generation from solid fuels was observed in Bosnia and Herzegovina, Kosovo, North Macedonia and Slovenia. Renewables excluding small hydropower plants, exhibited a significant output increase over the period 2015-2019, with RES generation rising in 2019 to 79.3 TWh, 84.55% higher than it was in 2015. Of those, solar PV yield rose by 131.8%, wind power by 54.35%, power generation from biomass plants by 116.2% and geothermal power by 162.9%.

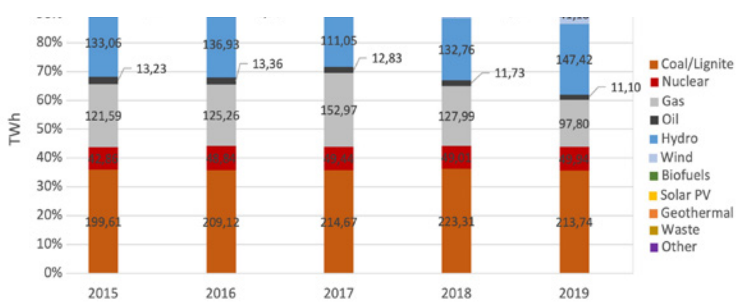
Annual power generation from RES was driven almost entirely by the integration of new projects, as seasonal variations had minimal effect to the annual output. Most notably, the output of solar PV increased significantly in 2018 and 2019, as the ratio of integration of new solar PV projects increased, driven by the revitalization of solar PV industry, which led to significantly reduced prices of PV panels, affecting regional investment.

Figure 10.38 **Development of power generation mix in SE Europe including Turkey during 2015-2019 in [GWh]**



Source: IENE/IEA

Figure 10.39 **Development of power generation mix in SE Europe during 2015-2019 in [TWh]**



Source: IENE/IEA

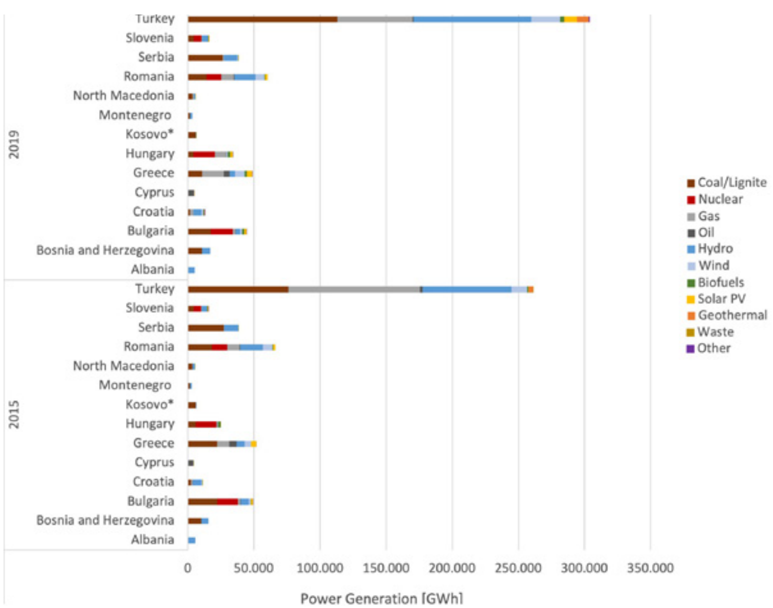
[79] https://www.eionet.europa.eu/etcs/etc-cme/products/etc-cme-reports/etc-cme-report-3-2020-trends-and-projections-in-the-eu-ets-in-2020/@@download/file/Report_ETS_03_2020_20201218.pdf

In 2019, approximately half of the power generated in SEE was produced in Turkey (i.e. 50.58%). Turkey's generation mix is dominated by coal and hydro, which contributed 32.58% and 25.58% of the total domestic generation, followed by gas and RES[80] at 16.36% and 12.53% respectively. The second largest power producer of the region, Romania, generated 60.16 TWh, i.e. 10.01% of the regional electricity output, with its power generation mix being the most diverse of all SEE states. More specifically, 20.46% of the Romanian generation mix was produced by coal/lignite-fired power plants, 22.85% derived from hydro, 16.31% from nuclear, 13.46% from gas units, 0.85% from oil and the rest 13.04% from RES, from which 9.79% was generated by windfarms, 2.57% from solar PV and 0.68% from biofuels. Greece was the third largest electricity producer in the region in 2019. The country has also diversified its generation mix over the period 2015-2019, decreasing significantly the share of lignite to the total generation mix from 36.46% in 2015 to 17.55% in 2019, while the share of gas has increased to 26.48%, with the share of oil declining to 7.26% and hydro also falling to 6.59%.

At the same time (2019) the share of RES in power generation rose to 20.82%, of which 6.43% came from Solar PV, 11.82% from windfarms and 2.56% from biomass units.

Bulgaria and Serbia in 2019 generated 7.36% and the 6.37% of the regional generation mix respectively. Bulgaria's generation mix was formed by 35.41% coal-fired generation, 33.97% by nuclear power, 6.94% by hydro, 4.37% from gas, 0.76% from oil and 9.18% from RES, namely 3.6% generation from biomass units, 2.88% solar PV and 2.7% wind. Serbia's generation mix remains dominated by coal which accounts for 67.25% of the total domestic generation while 25.92% comes from hydro, 2.16% from wind, 1.61% from gas 0.3 from biofuels, 0.23% from oil products and 0.04% from solar PV. Hungary produced 5.67% of the region's power output in 2019, while its generation mix has recorded significant changes over the period 2015-2019 with power generation from coal falling to 10.92% from 21.12% in 2015. As Hungary's domestic generation rose, the share of nuclear generation fell to 42.54% despite the improved availability of Paks NPP over the examined period. Moreover, a noteworthy change was the

Figure 10.40 **Power generation mix in SE Europe per country and source during 2015 and 2019 in [GWh]**



Source: IENE/IEA

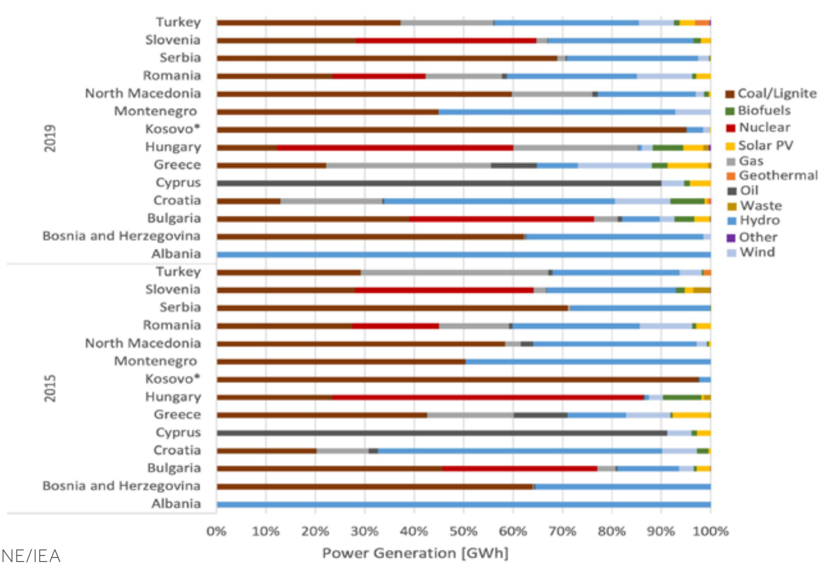
[80] Excluding small hydro

penetration of gas into Hungary's generation mix, rising to 22.45% from 15.44% in 2015. The rest of Hungary's generation mix were made by 0.57% hydro, 0.18% oil and 10.98% RES, of which 5.46% came from biomass plants, 3.62% from solar PV and only 1.9% from windfarms.

Bosnia and Herzegovina's generation mix in 2019 remained in a similar state as it was in 2015, with 61.3% of the domestically generated electricity coming from coal and 35.4% from hydro, with a small penetration of new wind power projects accounting for 1.5% of the total domestic power output. Kosovo's generation mix has seen minor changes over the last 5 years, with a small decline of coal share, which fell to 93.47% from 97.47% in 2015, while hydro rose to 3.25%, with 1.41% generated by wind and 0.15% by solar PV.Slovenia's generation mix has remained relatively unchanged over the period of 2015-2019, consisting of 35.34% nuclear power, 27.22% coal-fired power generation, 28.43% hydropower generation, 16.36% electricity generated from natural gas, 0.21% output from oil units and 12.53% generated by renewables, of which 6.27% was generated by windfarms, 2.76% by solar PV and 0.93% by biofuel-fired units. Croatia's power generation mix has changed significantly over the period of 2015-2019, with coal-fired generation falling in 2019 to 10.83% of the total domestic generation from 18.45% in 2015, while power generated by gas units has risen significantly, to 17.28% , hydro stands at 39.08%, and oil at 0.23%, while the share of RES has doubled, rising to 16.28%, of which 9.47% came from wind, 5.78% from biofuels, 0.55% from solar PV and 0.48% from geothermal power plants. Albania's domestic power generation still comes 100% from hydro as TPP Vlora is scheduled to operate on natural gas is not yet operational.

Cyprus has seen a small decline in the share of oil in its domestic power generation falling to 81.79% in 2019, while the share of solar PV rose to 3.84%, with wind accounting for 4.21% and generation from biomass plants to 1.06% of the total electricity generated in the country. Over the period 2015-2019 windpower has penetrated in Montenegro's generation mix making up 6.73% of the country's domestic power generation, while the share of coal and hydro has fallen to 41.91% and 44.64% respectively, while the country's import dependency has also fallen sharply. North Macedonia generated approximately 1% of the region's electricity predominately by its two coal power plants, which contributed 58.2% of the total domestic generation while hydro was responsible for 19.31%, gas for 15.88%, oil 1.01%, wind 1.69%, biofuels 0.91% and solar PV 0.38%.

Figure 10.41 **Power generation mix share in SE Europe per country and source during 2015 and 2019 in [%]**



Source: IENE/IEA

10.6 Market Operation

In SEE there are 9 Countries with fully liberalized electricity markets, namely Bulgaria, Croatia, Greece, Hungary, Romania, Slovenia, Serbia, North Macedonia and Turkey. In all, except North Macedonia, operate organized electricity wholesale markets. All non-EU member states in SEE region are Energy Community contracting parties and are in the process of aligning their legislation with the EU deregulating the electricity sector and liberalizing their internal electricity markets. Montenegro, Albania, Kosovo and North Macedonia have taken the necessary legislative steps to launch an organized wholesale electricity market in the immediate future.

In Serbia, Romania, Bulgaria and Hungary the majority of the volume of electricity traded at the wholesale level is held in the form of bilateral contracts between producers and suppliers, although in 2019 and 2020, spot electricity trading got a significant momentum. At retail level, there have been significant steps in Western Balkan countries in market liberalization and increase of customer eligibility to choose their own provider. Also, in the EU member states, and most significantly in Greece there has been an effort for reduction of retail market concentration from the incumbent supplier over the period 2015-2020.

Wholesale Market

The wholesale electricity markets in SEE are mainly organized through either bilateral over the counter (OTC) agreements or through centralized spot markets, while in most cases they remain highly concentrated. All electricity markets in SEE have for some time now been in a path towards liberalization. However, slower steps have been taken by WB6 countries, as among them only Serbia has an organized spot electricity market. Legislation either pending or not yet enforced affects the establishment and development of organized day ahead electricity markets and consequently the deregulation of electricity prices in Albania, Bosnia and Herzegovina (BiH) and Kosovo. Wholesale electricity prices are fully deregulated in Montenegro and North Macedonia, while the establishment of organized DAM is pending.

Wholesale electricity market developments

Significant developments have transformed the regional wholesale electricity markets over the past years towards a more competitive and transparent environment. Overall, the regional non-EU member states are unfolding legislative adaptations that will bring their wholesale competition closer to alignment with the European acquis communautaire. Moreover, EU member states are also progressing in adopting European legislation towards the goals for regional market integration and away from market distortions.

Greece: On November 1st 2020 the organized electricity market in Greece was reestablished transitioning from the "mandatory pool" to the European Target model market initiative, incorporating 4 electricity markets based on different operating time-frameworks, i.e. DAM, IDM, Balancing Market (BM) and derivatives (futures) market, which was priorly established on 23/03/2020. All markets except BM are operated by Greece's Nominated Electricity Market Operator (NEMO), HENEX, except BM which is run by Greece's TSO, i.e. IPTO. As a result, Greece aligned with all framework guidelines (FGs) and associated European Network Codes (NCs), in particular in relation to (interconnector) capacity allocation and congestion management (CACM), and balancing guidelines.

Bulgaria: With the amendments and supplements to the Energy Act (promulgated in the State Gazette, issue 41 of 21.05.2019) the next stage of the liberalization of the electricity market has commenced, as producers of electricity produced by renewable energy sources and HPPs, with a common installed capacity from 0.5 MW to 4 MW, are obliged to sell the entire amount of electricity produced to different segments of the organized wholesale market. In this regard, for this group of producers the existing model of compulsory purchase of the produced electricity from renewable energy sources has been abolished, as they have been integrated into the wholesale market at freely negotiated prices. As a result of these measures, the liquidity of the organized electricity (spot) market has increased, and hence the stability and transparency of the market. EWRC (KEVR) expects that the higher traded volumes will lead to the demand / supply of a larger volume and more diverse exchange products, resulting to expansion of the portfolio of the respective electricity market participants, which will give additional impetus in the development of spot trading.

Furthermore, during 2019 Bulgaria passed significant legislation for the rationalization of its electricity market, abolishing the electricity export tariff, and vesting authority to the regulator (EWRC) to regulate the electricity volumes provided in the regulated market.

North Macedonia: North Macedonia has made steps towards legislative preparedness for the launch of an organized wholesale electricity market including a day ahead and an intra-day market. However, currently (as of Feb 2021), only the market on Bilateral Agreements operates in the country. The roadmap for the establishment of organized wholesale market in North Macedonia has progressed with the nomination of MEMO, the National Electricity Market Operator of North Macedonia, as a NEMO of North Macedonia[81] and the next step is the launch of the day-ahead market, which MEMO has scheduled to go live on 2021. Moreover, since the liberalization of North Macedonia's electricity market by law, on July 1st, 2019, the suppliers, traders, and producers of electricity without prior consents, i.e., approvals by the Energy Regulatory Commission, are entitled to conclude mutual agreements on electricity purchase and sale. As a result, the Energy Regulatory Commission of North Macedonia will no longer regulate the electricity production price of the largest electricity producer in North Macedonia. As a result of this reform, a new member has emerged in the Wholesale Electricity Market, i.e., EVN HOME DOO Skopje, a legal entity founded by a Consortium of EVN Makedonija AD Skopje and EVN Elektrosnabduvanje DOOEL Skopje. This Consortium was selected as a Universal Supplier, under the Public Open Call competitive procedure, conducted by the government of the Republic of North Macedonia, according to which, and in accordance with the Law on Energy, the Universal Supplier shall be a sole legal entity[82].

Hungary: Pursuant to the Electricity Act, the Hungarian government may implement a green and co-generation certificate scheme upon the HEO's recommendation. Under such a scheme, all end-users (or generators) would be obliged to purchase a certain amount of green certificates based on their overall consumption[83].

Romania has also further liberalized its electricity market in 2020 introducing a new framework for a new trading system for long-term PPAs, which are long term directly negotiated bilateral power purchase agreements with physical delivery.

In addition, according to the same new secondary legislation for the implementation of EU Regulation 2019/943 for the internal market in electricity (Order 236: *"for the approval of rules for elimination and/or mitigation of the impact of measures or policies restrictive to the formation of prices on the wholesale electricity market"),* the wholesale market is fully liberalized, participation in organized markets is now voluntary and free formation of wholesale prices based on supply and demand market rules is encouraged, with no minimum or maximum threshold on wholesale electricity prices, including price balancing. The new reform introduces also the facilitation of electricity sales through aggregation, meaning that final customers may participate in organised electricity markets directly if their approved installed power is over 500 kW or by aggregation if it is lower.

[81] https://www.europex.org/members/memo/
[82] https://erc.org.mk/odluki/Annual%20Report%20ERC%202019%20-%20EN.pdf
[83] https://cms.law/en/int/expert-guides/cms-expert-guide-to-electricity/hungary

Turkey: Following the liberalisation and privatisation of the electricity market in 2001, electricity generation, distribution and supply were opened up to private entities and are now carried out by both private and state-owned companies. EXIST (Energy Exchange Istanbul) was officially established in March 2015. This was an important step towards the liberalisation of the electricity market. Organised wholesale electricity market had been operated by Turkish Electricity Transmission Corporation (TEİAŞ) since 2009. Wholesale electricity markets have been operational on EXIST since 2015. Development of physically settled power futures markets are also underway. The depth and liquidity of the market is expected to benefit from the derivatives market that will be established in 2021, as well as a range of contracts over various time horizons and delivery windows that have become operational in 2020[84].

Montenegro is in the process of establishing an organized DAM through its prospective power exchange MEPX, expected to be deployed during 2020, but has been delayed. Finally, Serbia has introduced electricity futures market in 6/2019.

The following is a summary of the wholesale electricity market status in SEE with respect to its liberalization and competition:

- Eight countries in the region, namely Bulgaria, Greece, Romania, Hungary, Serbia, Croatia, Slovenia and Turkey, have liberalized wholesale electricity markets, operating established internal spot electricity markets operated by their designated NEMOs which are the following: IBEX, HEnEx, OPCOM, SEEPEX, CROPEX, BSP Southpool and EXIST respectively.
- Significant portion of electricity trade on the wholesale level is carried out via bilateral contracts between producers and suppliers in Turkey, Serbia, Hungary, Romania and North Macedonia.
- Serbia's organized electricity market through SEEPEX has limited competition and liquidity, while HUPX and OPCOM have seen increased participation and liquidity over the period 2018-2020.
- Organized wholesale electricity markets are not operating in Albania-Kosovo, North Macedonia and Montenegro even though respective entities charged with the role of market operator have been established, namely ALPEX (Albania-Kosovo), MEMO (North Macedonia) and MEPX (Montenegro).
- Competitiveness of coal/lignite in regional wholesale markets is expected to be maintained for incumbent generators in Romania, Bulgaria and Hungary, as they opted to continue receiving free emission allowances during the fourth ETS trading phase in 2021-2030

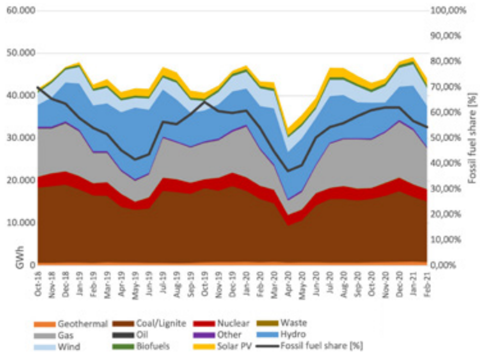
[84] https://www.iea.org/reports/turkey-2021

Wholesale Electricity Market Prices

The state of competition in organized wholesale electricity prices is as of late partially driven by carbon prices, which moved decidedly above 30 €/tCO_2 in the final month of 2020 and surged to more than 40 €/tCO_2 in March 2021. This is particularly significant for the heavily coal dependent SEE region, as it puts coal and lignite power plants at a greater disadvantage against their less polluting gas-fired competitors. As the outlook for emission-intensive technologies worsens, more and more early coal retirements are announced across Europe. The most significant of these decisions for SEE is Greece's aim to put all existing lignite capacities out of operation by 2023. Coal generation in Bosnia and Herzegovina, by contrast, rose by 8% in 2020.

Analysing the organized wholesale market performance of SEE, we observe a declining trend in spot electricity prices in SEE Europe from Q4 of 2018 onwards. This is partly driven by the decreasing share of fossil fuels in regional power generation. It is evident that a slump in the share of fossil fuels in Q2 of 2019 and 2020 was reflected in a dip of spot electricity prices. Also spot electricity prices during the summer are becoming less and less pronounced as solar PV yield emerges after the recent integration of new capacities in the region. The hydrological cycle was one of the main factors driving spot electricity prices in 2019, as it was one of the main source of peak load generation in the region with significant availability of water reserves at large hydropower reservoirs throughout the year. On the other hand, in 2020, the main spot electricity price driver was the shock of electricity demand plunging in April, as a result of the Covid-19 pandemic mitigation measures. This was mostly underlined in the eight major regional markets, where power generation receded significantly, by approximately 25% in comparison to March and 20.8% lower than in April of 2019, as shown in Figure 10.42. Demand gradually recovered regionally by July 2019 and was maintained at normal levels until the end of 2020.

Figure 10.42 **Monthly Power Generation mix development in SEE** (including Bulgaria, Croatia, Greece, Hungary, Romania, Serbia, Slovenia and Turkey) and development of fossil fuel share in SEE power generation mix over the period 2019 - 2020



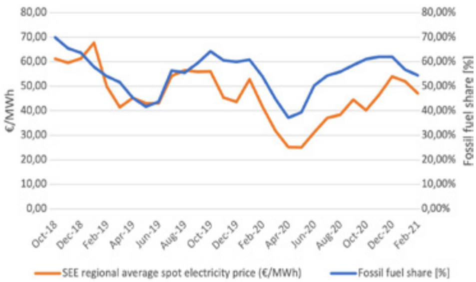
Source: Entso-e, Eurostat, IPTO, TEIAS, MAVIR, Transelectrica

Observing the regional average spot electricity price, this peaked in January of 2019 at 67.7 €/MWh and followed a downward trajectory since. Regional average prices settled between 42 and 45 €/MWh in the period of March – July 2019 driven down by relatively high hydropower yield. In 2020, the demand decline in the Q2, drove regional markets to rely less on the hydrological cycle for seasonal spot price reduction conserving the regional hydro reservoirs. The lowest monthly regional average spot electricity price over the period 2019-2020 was formed on May 2020, at 25.09 €/MWh, partly driven by the dipping of gas prices and the high performance of hydro and variable renewables as demand plummeted. It is notable, that in April and May of 2020, as a result of dipping demand and the high output from variable RES, the share of fossil fuels in the regional generating mix fell below 40%, at 37.14% and 39.41% respectively. This however indicates that the region is still heavily reliant on fossil fuels, namely coal, for power generation, as at the same period the total European generation mix exhibited a higher reduction of the share of fossil fuels, which shrunk to approximately 30%[85]. In the second part of 2020, Q3 and Q4, lignite power generation in SEE rose, driven by recovering demand and rising gas prices, which increased its market competitiveness to regional gas-fired generation.

[85] https://ec.europa.eu/energy/sites/default/files/quarterly_report_on_european_electricity_markets_q4_2020.pdf

Figure 10.43 shows the close correlation of regional spot electricity price development and the share of fossil fuels in the regional generation mix, as this is captured by the performance of the electricity sector in 8 major electricity markets in the SEE region (Bulgaria, Croatia, Greece, Romania, Hungary, Serbia, Slovenia and Turkey).

Figure 10.43 **Average Annual Electricity Prices to Spot Markets (DAM) in SE Europe for 2019 and 2020**



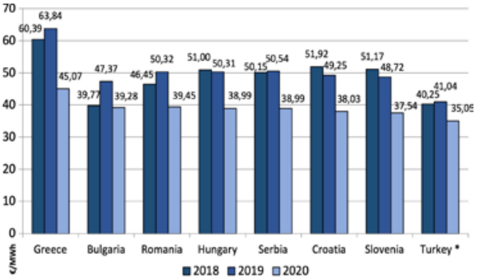
Source: Entso-e, Eurostat, IPTO, TEIAS, MAVIR, Transelectrica HEnEx, IBEX, OPCOM, EXIST, BSP Southpool, CROPEX, SEEPEX, HUPX

Wholesale Prices in 2019

Wholesale electricity prices in 2019 rose in Greece, Bulgaria, Romania, Serbia and Turkey, as a result of reduced domesticlignite-fired baseload generation in Greece and reduced hydropower in the Autumn period, as drought affected mostly the regional wholesale markets, namely in Romania, Bulgaria, Serbia, Greece and Turkey. On the other hand, lower demand mitigated the incremental effect of drought to electricity prices in the coupled wholesale markets of Slovenia and Croatia, where wholesale prices receded.

Turkey even though experiencing drought in the autumn-winter period, has increased significantly its share of hydraulic and wind energy in its electricity mix as result of deploying many new hydro and wind projects in the period 2018 - 2019. The highest average annual spot price was formed in Greece at 63.83 €/MWh, while the lowest was seen in Turkey at 41.04 €/MWh

Figure 10.44 **Average Annual Electricity Prices at Spot Markets (DAM) of SE Europe for 2019 and 2020**



*€ - TRY Equivalence is based on daily average rates by ECB

Source: IBEX, CROPEX, HENEX, HUPX, OPCOM, SEEPEX, BSP South Pool, EXIST

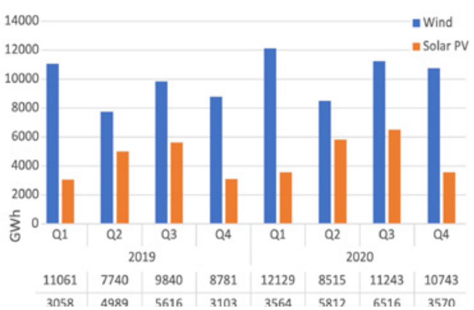
Wholesale Prices in 2020

In 2020, average annual spot electricity prices decreased in the region affected by reduced demand, which was most pronounced in Q2. Most specifically, monthly average prices were driven below 30 €/MWh in all regional wholesale markets in April, and also in May with the exception of Greece, where the monthly average price was formed at a higher level, equal to 34.3 €/MWh. Gradually, spot electricity prices rose following the electricity demand increase, peaking in December at a range of 54.5 – 59.0 €/MWh, with the highest monthly average price being formed again in Greece at 58.93 €/MWh.

Moreover, we observe convergence of the Greek spot electricity prices to the regional average in the months when the Greek system exhibited high windpower generation, i.e. September, November and December, when the monthly windpower output in Greece rose above 800 GWh. In addition, in 2020 very high regional output from variable renewables, namely wind and solar PV, assisted the regional electricity price decline in addition to the overall lower demand, particularly pronounced in the Q2.

More specifically, wind power was at very high levels in Q1, Q3, but the most significant y-y increase of wind power output was observed in Q4 of 2020, when generation from regional windfarms rose to 10.74 TWh, i.e 22.35% higher than it was in 2019. Similar to wind, commissioning of new Solar PV projects drove the annual regional Solar PV yield in 2020 higher by 16.09% than it was in 2019, which affected significantly spot electricity prices at mid-day hours.

Figure 10.45 **Development of power generation from Windfarms and Solar PV during 2019 and 2020 in SEE**



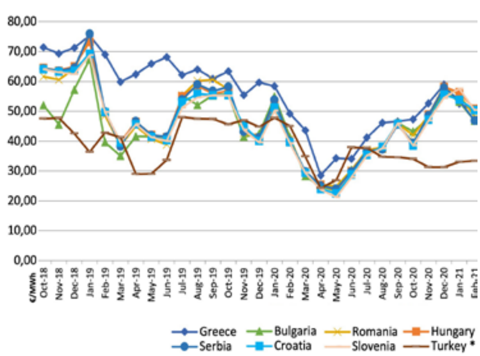
Source: Entso-e, Eurostat, IPTO, TEIAS, MAVIR, Transelectrica

Looking at Figure 10.47 we see a higher price convergence of spot electricity prices in SEE's day ahead markets in 2020 than in 2019. More specifically, in 2019, Greece's electricity prices were significantly upwards offset from the regional average throughout January – July. Moreover, daily spikes in the Bulgarian wholesale electricity market were mostly driven by unplanned outages of critical baseload capacities such as the outage of Kozloduy NPP's Unit 6 on 3/7/2019 and the unplanned outage of Maritsa East 3 generator 1 on 12/3/2019. Similar price spikes have been observed in SEEPEX and OPCOM.

Such events include a price spike at SEEPEX on 29/8/2019 driven by an unplanned outage of Nicola Tesla A TPP generator 5 and a price spike at OPCOM exchange on 19/9/2019 due to an unexpected outage of 650 MW Unit 1 of the Cernavoda NPP on Wednesday 18/8/2019. Overall, Greek day-ahead prices were relatively elevated on some occasions in November of 2020 due to themaintenance of key interconnectors with Italy and Bulgaria, but were more convergent with the rest of the region in December.

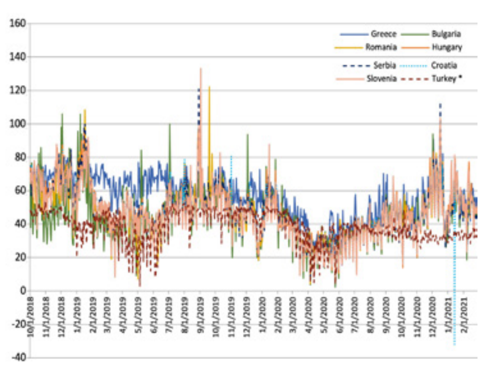
Additionally, spot electricity prices in Turkey's EXIST have moved downwards despite the overall demand recovery in Autumn of 2020 onwards. This can be partially explained by the pressure exerted by the downtrend value of the Turkish lira on generation costs during September – November of 2020.

Figure 10.46 **Average Monthly Electricity Prices at Spot Markets (DAM) of SE Europe during Oct 2018 -Feb 2021**



Source: Entso-e, Eurostat, IPTO, TEIAS, MAVIR, Transelectrica

Figure 10.47 **Daily average power prices on the day-ahead market in SEE markets during 2018 Q4 – 2021 Q1**



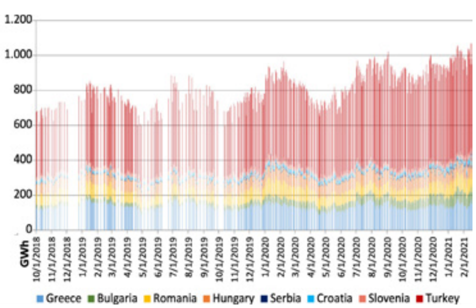
*€ - TRY Equivalence is based on daily average rates by ECB

Sources: IBEX, CROPEX, HENEX, HUPX, OPCOM, SEEPEX, BSP South Pool, EXIST

Wholesale Electricity Market volume and liquidity

There has been an increase in the volume of electricity traded in regional exchanges over the past 3 years (2018-2020). Liquidity has increased in IBEX and SEEPEX as electricity market liberalization is progressing in Bulgaria and Serbia. The coupling of Croatia with Slovenia in June of 2018 led to a surge of liquidity on CROPEX in the following year (2019), with approximately 29% and 35% of the total volume of internal electricity market, i.e. 5.26 TWh and 6.08 TWh being traded in the spot market of CROPEX during 2019 and 2020, respectively, from 13% in 2018. The volume of electricity traded in the spot markets of HEnEx was driven by internal market demand and cross border competition, which brought trade volume down despite the electricity demand increase in Greece in 2019. Similarly, BSP Southpool's volume in DAM receded in 2020, driven by a significant decline in demand in Slovenia's internal electricity market. In HUPX, increased participation brought the traded volumes in DAM upwards, despite Hungary's electricity demand declining in 2020.

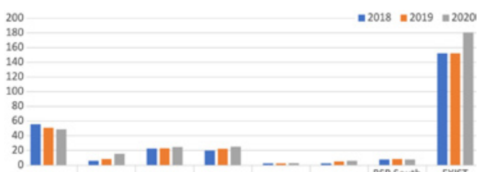
Figure 10.48 **Daily volumes on the day-ahead market in SEE markets [GWh]**



Source: IBEX, CROPEX, HENEX, HUPX, OPCOM, SEEPEX, BSP South Pool, EXIST €

Moreover, in 2018, the major Hungarian power plants sold the majority of the electricity they generated on the basis of mid-term agreements concluded with the former public utility wholesaler, Magyar Villamos Művek Zrt. (MVM). In the same year about one fifth of the electricity generated by power plants was sold directly on the free market in the framework of short term (mostly one year) contracts[86]. This volume increased moderately in the following years, 2019 and 2020, but the emergence of RES generation has pushed the electricity volumes traded in the organized market higher as the volumes of renewable electricity sold by the RES feed-in scheme operator MAVIR Zrt rose. In Serbia electricity sold in the open market has been gradually increasing since 2015, accounting for 14,261 GWh or 49.2% of the final customers' consumption if we exclude the energy delivered via supply of last resort, or a total of 42.18% of the total domestic electricity consumption. The electricity traded in the spot electricity market of Serbia, in SEEPEX, in 2019 and 2020 followed the incremental trend exhibited since its launch in 2016, rising to 2.53 TWh and 2.82 TWh in each year respectively, exhibiting a year-to-year increase of 9% and 11.5% respectively. Most, of the electricity traded at SEEPEX was electricity for loss recovery purchased by EMS and exporting demand.

Figure 10.49 **Trade Volume in SEE electricity exchanges on DAM framework**



TWh	HENEX	IBEX	OPCOM	HUPX	SEEPEX	CROPEX	BSP South Pool	EXIST (EPIAS)
2018	55,85	6,05	22,7	19,91	2,32	2,38	7,47	152,32
2019	51,21	8,39	23,13	22,25	2,53	5,26	8,28	152,11
2020	48,92	15,45	24,93	25,24	2,82	6,08	7,61	180,54

Source: IBEX, CROPEX, HENEX, HUPX, OPCOM, SEEPEX, BSP South Pool, EXIST

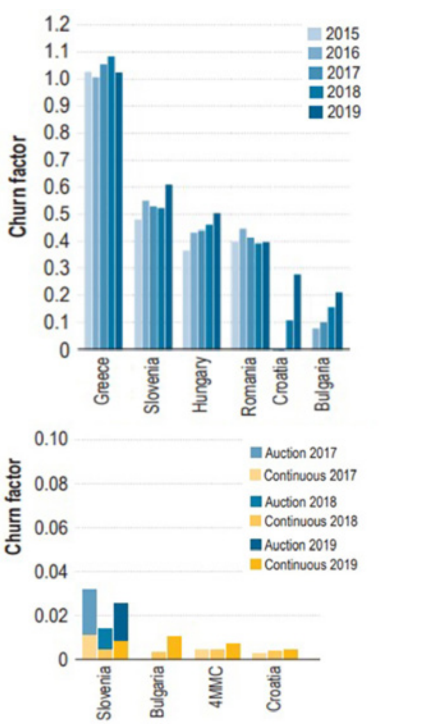
New secondary legislation contributed to further liberalizing wholesale electricity market in Romania, by allowing free price formation based on supply and demand principle without minimum or maximum threshold on wholesale electricity prices. Such measure has driven a higher participation in the OPCOM electricity exchange in 2020. This is exhibited by the higher volume of electricity exchanged in the DAM framework by 7.2% despite the decline in domestic electricity demand the same year by 5.42%.

[86] http://www.mekh.hu/download/9/01/c0000/hea_annual_report_2018.pdf

Market liquidity

Market liquidity can be measured in several ways. In this section, the 'churn factor' is utilized to express the liquidity of the major markets in SEE, defined as the overall volume traded through exchanges and brokers expressed as a multiple of physical consumption. This metric provides an indication of the relative 'size' of the market compared to its physical size and it is relevant to all market timeframes. [87]

Figure 10.50 **Churn factors in major SE European (a) DA markets and (b) ID markets – 2015–2019**



Source: ACER

Overall, we observe gradual increases in liquidity in Croatia, Bulgaria and Hungary in the DA market framework over the period 2015 – 2019. More specifically, the volume of electricity trade in the day ahead market in 2019 increased by 21% of actual consumption from 8% in 2016 in Bulgaria, when IBEX commenced operation of its DAM. In Croatia, the churn factor in DAM rose to 0.28 in 2019 from 0.11 in 2018, while Hungary has seen gradually a significant increase of the ratio of electricity volumes traded in the DAM framework to the sheer volume of physical consumption, rising to 51% in 2019 from 37% in 2015. Slovenia has seen fluctuations in the liquidity of its DA market over the period 2015 – 2019, but overall, there was an increase from a 48% (churn factor: 0.48) of the volume consumed in the Slovenian internal electricity market in 2015 to 61% (churn factor: 0.61) in 2019

In the intraday market the most notable increases in liquidity are observed in the 4MMC markets, namely Hungary and Romania driven by their integration to European SIDC through the XBID platform during the Q4 of 2019 (November 2019). Slovenia has seen high liquidity in comparison to the other regional markets due to the possibility to trade in implicit Intraday Auctions on the Slovenian-Italian border since 21st of June 2016. In Bulgaria, IBEX has also improved its volumes on IDM after the XBID SIDC market coupling on BG-RO border (November 2019). The region is expected to see more activity in the intraday framework with the launch of the intraday market in Greece and the progress of the XBID project, with the expansion of the European single intraday coupling across SEE.

Intraday Markets

Intraday and balancing markets are becoming increasingly important as power generation is increasingly relying on highly variable stochastic RES. Currently the state of play in the regional electricity market is that the majority of variable RES are supported under a specific scheme, therefore are dispatched by priority, reducing the remaining demand which is exposed to market conditions. A well-functioning intraday market in turn allows wind and solar generators to correct their position as their actual output deviates from their forecast. As renewables are gradually losing priority of dispatch, the intraday market will allow them to optimize their trading strategy and maximize the output sold.

[87] https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202019%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf

The balancing market is also an important precondition for growing renewable penetration, as it gives generators the ability to actively participate in correcting imbalances in supply and demand in real time. It also promotes the deployment of flexible technologies, such as batteries, which will be crucial to the success of a renewables-centred electricity system.

The integration of intraday markets in **Romania**, Bulgaria, Hungary and Croatia in the XBID project and SIDC in 2019 resulted in an immediate increase in participation and liquidity in the intraday market framework. More specifically in Romania, during the first 23 days of cross-border trading, 36,070 MWh was traded on Intraday Market, which is approximately 24% of the volume traded in the second half of 2019. Out of this volume corresponding to the first 23 days of cross-border trading, 4,479 MWh was exported, 9,969 MWh imported, and 21,622 MWh traded internally.

The launch of the intraday market coupling in Romania resulted in a twofold increase in volume of the daily concluded trades, from a quantity of 780 MWh traded locally on average every day during the second half of 2019 to more than 1,560 MWh traded on average each day after the coupling went live. Also in Romania, OPCOM saw negative spot electricity prices for the first time since its launch in both intraday and the DAM framework in 11/12/2019 during the off-peak hours of 01:00-04:00 a.m.[88] Similar growth of volume in intraday market framework has been exhibited in Bulgaria, with IBEX registering new record volumes traded, currently standing at 18.17 GWh/day (21/1/2021)[89], while the IDM volumes prior to the integration of Bulgaria to SDIC were significantly lower to a range of 0.2 – 6.0 GWh/day.

In **Hungary**, HUPX experienced great growth in intraday volumes at the end of 2019 thanks to going live with XBID on November 19. On the intraday market the total traded volume in 2019 reached 155,788 MWh and was nearly 3 times higher than in 2018, when 55,093 MWh was traded on the ID market. The highest daily traded volume was 5,565 MWh, achieved on 13th December 2019. Furthermore, the Exchange also welcomed altogether 7 new members on its intraday market and, thus, had 36 active members while on the day-ahead market 6 new members were admitted and the membership number reached 59 by the end of 2019.

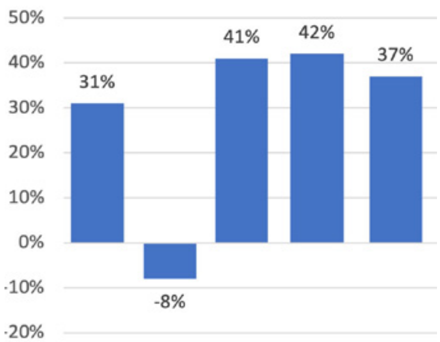
In 2020 the total traded volume increased by 13,45% to 25.23 TWh compared to 22.24 TWh in 2019. The average daily traded volume was 68.95 GWh. The highest daily traded volume reached 90.32 GWh on July 4, 2020, which is a record of daily traded volume since the launch of the HUPX DAM market. The number of newly admitted members in HUPX's intraday market in 2020 was 64[90].

Cross border electricity trade

Cross border electricity trade has been emerging over the last decade following a significant increase of interconnectivity in the regional electricity markets, but also of the interconnectivity of the region with neighboring markets, namely CEE and Italy. Some notable changes in available NTC over 2018 – 2019 have been made, as observed in Figure 10.51, internally to the NTC of the exporting flows from Romania to Bulgaria. Moreover, significant increases of available NTC have been made with regard to the importing capabilities of the region in the borders of Greece with Italy, and Slovakia with Hungary. Additionally, increases in the NTC of the interconnectors of Greece with Italy and Hungary with Austria, have led to a significant increase of the SEE region's exporting capability during 2018 – 2019.

88 https://www.opcom.ro/anunturi_stiri/comunicate.php?id_comunicat=1152&lang=en&id_tip_comunicat=1
89 https://ibex.bg/2021/01/23/%D1%82raded-volume-record-on-the-intraday-market-2/ (Accessed on 20/7/2021)
90 https://hupx.hu/uploads/Piaci%20adatok/DAM/%C3%A9ves/HUPX_DAM_OLAP_Yearly_external_4MMC_2020.pdf

Figure 10.51 **Changes in tradable capacity (NTC) in SEE and its borders with neighboring regions regions** (excluding differences lower than 100 MW) – 2018–2019 (MW, %)



Source: ACER calculations based on ENTSO-E data

The interconnectivity levels, an important metric which depicts the ratio of the sum of the import capacities versus the installed generating power, can also depict a clearer picture of the market and infrastructure development towards the expansion of regional and cross regional electricity trade in SEE. These have risen steadily in the region over the past five years and in 2020 all regional systems achieved the European goal of 10%[91] by 2020. Moreover, all regional markets except Romania and Greece are above the European interconnection level target for 2030 of 15%, with Western Balkan countries presenting significantly high interconnection levels, above 50%, which is anticipated given that the majority of their power generating capacities is coming from dispatchable thermal power plants.

Moreover, Greece is expecting significant new interconnection capacity to be added in its borders, as a result of the commissioning of the new Greek-Bulgaria interconnector at Nea Santa HVC - Maritsa East Substatio[92], as well as lignite phasing out, which is expected to boost its interconnectivity levels above the target, balancing the integration of new domestically installed RES units.

Similarly, in Romania the reinforcement of the interconnection with Hungary and Serbia with the commissioning of a 400 kV interconnection line between Hungary and Romania and the Mid Continental East corridor (Serbia – Romania) respectively, along with domestic thermal capacity decommissioning is expected to bring interconnectivity levels above the target value for 2030.

Table 10.3 **Interconnectivity levels of electricity markets in SEE in 2020**

Country	Interconnectivity level [%]
AL	64.1%
BA	51.0%
BG	19.6%
CY	0.0%
GR	12.9%
HR	95.3%
HU	72.6%
ME	209.8%
MK	134.1%
RO	11.5%
RS	50.0%
SI	108.8%

Source: Energy Community[93] and IENE calculated with data from regional TSOs [94]

Rules for cross-border transmission capacity allocation: Even though interconnectivity has been increasing at a fast pace in the SEE region over the past years, with total interconnection capacity expected to rise by 50% until 2025, only a small fraction of the interconnection capacity is currently available to traders. The NTC values are currently small in all countries.

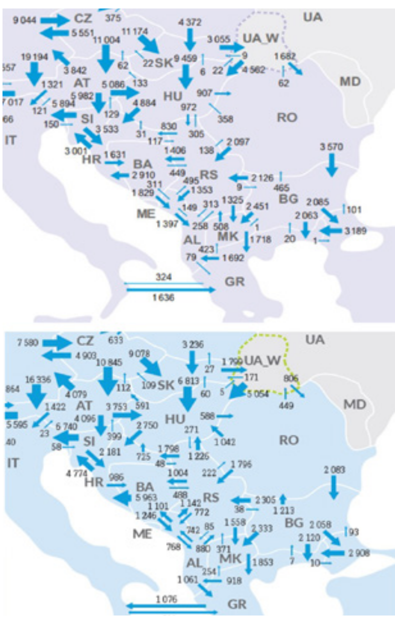
Therefore, below 30% of interconnection capacities are on average available for commercial operations. In Greece, the NTC values range from 11% to 34% of the thermal capacity of interconnectors, while large exporters, such as Bosnia-Herzegovina and Bulgaria, as well as smaller exporters such as Romania and Serbia, also use restrictive NTC values, which represent a range between 19% to 43% of interconnection capacities in these countries, measured on NTC values for 2018.

[91] https://ec.europa.eu/energy/topics/infrastructure/electricity-interconnection-targets_en?redir=1
[92] https://www.admie.gr/en/erga/erga-diasyndeseis/diasyndesi-elladas-boylgarias
[93] ECS, 2021, "Electricity Interconnection Targets in the Energy Community Contracting Parties"
[94] https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP2018/System_Need%20Report.pdf

Currently, the rules for allocation of available cross-border transmission capacities between regional bidding-zones include various schemes, such as: (a) Bidding over last accepted marginal price, extensively used in the DAM framework, and (b) First-come first served scheme, used extensively in explicit auctions for capacity allocation in the IDM framework (i.e. Serbia-Albania, Serbia-Montenegro etc.). Currently, the capacity allocation auctioning in SEE region is performed either via explicit auctions, auctions through Joint allocation Office (JAO), join auctions or split 50%/50% auctions. The Integration of Electricity markets via the Target model market initiative is an ongoing process, so with regard to interconnection projects and bilateral market coupling initiatives, these are just blocks towards building an integrated multilateral regional market. ACER is in charge for the monitoring and surveillance of energy markets towards this direction, and its involvement is meant to enhance further electricity market development and ensure its smooth operation.

Volume of cross border electricity trade

Map 10.5 **Physical electricity flows in SEE in GWh in (a) 2017 and (b) 2018**



Source: ENTSO-e

SEE Europe, according to data from Entso-e, remains a net importing region with the volume of imported electricity highly dependent on prevailing hydrological conditions. A concrete example is the comparison between the years 2017 and 2018. 2017 was a dry year leading to lower output from the hydropower plants of the region, which yielded an approximate 111.05 TWh/year. On the other hand, 2018 was peak year for the regional hydrological cycle with approximately 132.76 TWh generated by regional hydropower plants. As a result, we observed a significant decline in the net importing position of the region, which fell to 11.87 TWh of net electricity imports from 21.99 TWhs in 2017. Additionally, the emergence of RES also affected positively this outcome, and is expected over time to reduce the volumes of electricity flows towards SEE from Central Europe, given the high potential for integration of RES in the Western Balkans, Greece and Turkey.

Within the SEE region, the most important net electricity exporters are Turkey, Bosnia and Herzegovina and Bulgaria, with net exports in 2018 amounting to 4.86 TWh, 4.61 TWh and 3.88 TWh respectively. Turkey has seen its net exports soaring in 2018[95] to a threefold in comparison to 2017 as a result of significant increase of domestic generation from renewables, most notably solar PV, which came online in the period 2017-2018. Moreover, hydropower was the main driver behind the boost of net electricity exports in BiH by approximately 150% in comparison to 2017. Meanwhile, Bulgaria, a traditional net exporter, saw its net exports declining by 44.4% in 2018, losing competitiveness against other regional markets partly due to the regional high hydropower output, but still maintained at relatively highvolumes. Another notable reason for the loss of competitiveness of Bulgarian market in 2018 was the low output of variable renewables, namely windfarms and solar PV, which came as a result of RES investment stagnation amidst a relatively low performing year for wind and solar PV.

[95] The exporting position of Turkey was presenting only with regard to its western borders with Greece and Bulgaria.

The year-to-year volatility, driven by the hydrological cycles is manifested in the case of Albania, which turned from a net importer in 2017, with net imports of 2.91 TWh, to a net exporter in 2018 with net electricity exports of 0.91 TWh. Romania, increased its net electricity exports in 2018 by 80.5% in comparison to 2017. Also, Montenegro, was driven from a net importing to a net exporting position in 2018, with however a low volume of net exports of 251 GWh, a surplus of approximately 3.4% of the country's domestic consumption.

Table 10.4 **Physical electricity flows between SEE electricity markets and neighboring markets in 2018**

	Import Countries															
Export Countries	AL	BG	HR	GR	HU	RO	RS	BA	MK	ME	SI	TR	AT	IT	UA	SK
AL				1061			880			742						
BG				2120		1213	2305		2333			93				
HR					725		48	986			4774					
GR	918	7							254			10		1076		
HU			2750			588	271						591		5	60
RO		2083			1042		1796								449	
RS	85	38	1798		1226	222		1004	1558	772						
BA			5963				488			1246						
MK		0		1853			371									
ME	768						1142	1101								
SI			2181										399	6740		
TR		2058		2908												
AT					3753						4096					
IT				611							58					
UA					5054	806										
SK					6813											

Source: ENTSO-e , Note: Kosovo and Metohija were considered part of the Serbian market in the reference year

Table 10.5 **Physical electricity flows between SEE electricity markets and neighboring markets in 2017**

	Import Countries															
Export Countries	AL	BG	HR	GR	HU	RO	RS	BA	MK	ME	SI	TR	AT	IT	UA	SK
AL				79			258			149						
BG				2063		465	2126		2451			2085				
HR					31		117	1631			3001					
GR	1692	20							423			1		324		
HU			2750			907	972						133		22	6
RO		2083			358		2097								62	
RS	313	9	830		305	138		1406	1325	1353						
BA			2910				449			1829						
MK		1		1718			508									
ME	1397						495	311								
SI			3533										129	5894		
TR		101		3189												
AT					5086						5982					
IT				1636							150					
UA					4562	1682										
SK					9459											

Source: ENTSO-e , Note: Kosovo and Metohija were considered part of the Serbian market in the reference year

The main electricity importers in the region are Hungary, Greece and Croatia with net electricity imports in 2018 of 14.3 TWh, 6.3 TWh and 6.2 TWh respectively. Hungary imported approximately the 31.4% of its domestic electricity consumption in 2018, with its net electricity imports however declining slightly by 4.4%. Notably, the net electricity imports of Hungary in 2018 came increasingly from within SEE, while electricity inflows from Central Europe, namely Austria and Slovakia, declined notably. Greece, who imported approximately 27.8% of its domestic electricity consumption in 2018, saw its net imports rising only marginally (+1% y-y) despite a small slump in domestic demand that year, driven by highly competitive electricity prices in the Balkans. Croatia's net electricity imports also increased by 17.5% in 2018 primarily as a result of higher domestic electricity demand accounting for approximately 34.7% of the country's domestic electricity consumption. Moreover, Serbia maintained net importing positions, with low volumes of net imported electricity in comparison to the sheer domestic electricity consumption of approximately 1.7%. In the same year, net electricity imports

in Serbia were driven downwards by 55.5% primarily driven by higher domestic hydropower yield and lower domestic electricity demand. North Macedonia remained a relatively stable net importer throughout the period 2017-2018, with net imports standing at 1.92 TWh in 2018, accounting to approximately 26.1% of the country's total domestic consumption.

Figure 10.52 **Net importing/exporting (-/+) position of regional electricity markets in SEE in 2017 and 2018**

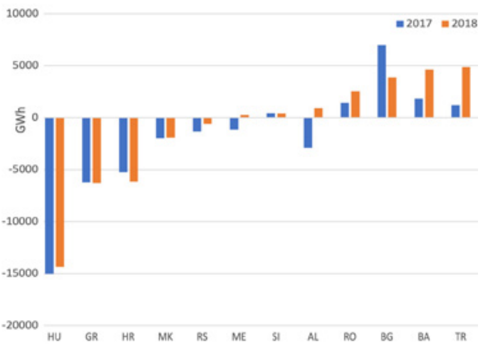
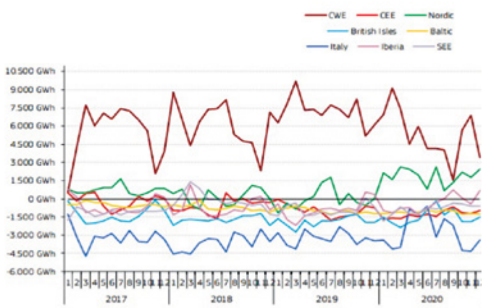


Figure 10.53 **European cross-border monthly physical flows by region**



Source: DG Energy

Additionally, according to DG Energy's metrics, SEE is a net importing region with occasional net exporting positions. Such occurrences were most recently realized in September and December of 2020 and prior to that, in November and December of 2019. In Q4 of 2019, most notably in November and to a lesser extent in December, very high precipitation in the SEE region drove spot electricity prices down, making SEE markets competitive and the region a net electricity exporter to the west, with most markets in the Western Balkan region maintaining a net exporting position in November, namely Serbia, Croatia and Bosnia and Herzegovina, while also Bulgaria enhanced its net exporting position throughout this period.

During 2020, in September, the severe drought phenomena were responsible for prolonged outages of the nuclear baseload of France, driving spot electricity prices higher in Central and Western Europe and as a result the competitiveness of SEE increased, partly due to intense wind phenomena driving wind power generation upwards and spot prices down. Similarly, in December of 2020 wind power surges in SEE coinciding with lower demand drove electricity exports from SEE towards Central Europe in the last week of the year (week 53)

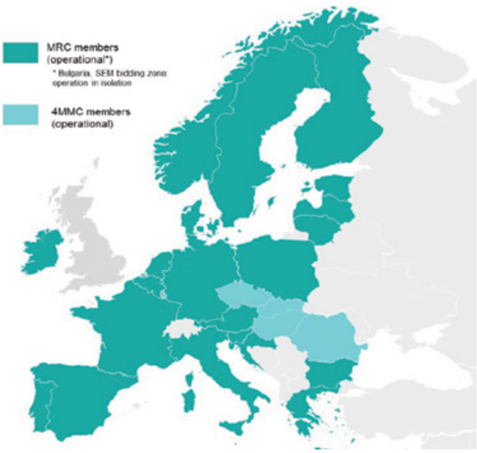
Projects for electricity market coupling in the SEE region

Day Ahead Market framework

The Single Day-Ahead Coupling (SDAC) Project: The project is designed to manage and develop procedures and technical feasibility for the implementation of a single day ahead pan-European market. The project for one single European market is in line with the principle of Price Coupling of Regions as expressed in the European legislation through the COMMISSION REGULATION (EU) 2015/1222 for "establishing a guideline on capacity allocation and congestion management" (CACM)[96]. SDAC was launched initially in the countries of Western and Central Europe and is gradually expanding. Its main purpose is the optimized and full use of energy resources through implicit day-ahead trading. More specifically, SDAC allocates scarce cross-border transmission capacity in the most efficient way by coupling wholesale electricity markets from different regions through a common algorithm, simultaneously taking into account cross-border transmission constraints, thereby maximising social welfare. The aim of SDAC is to create a single pan European cross zonal day-ahead electricity market. In principle, an integrated day ahead market increases the overall efficiency of trading by promoting effective competition, increasing liquidity and enabling a more efficient utilisation of generation resources across Europe[97].

[96] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015R1222&from=EN
https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52018SC0376&from=EN
[97] http://www.nemo-committee.eu/sdac

Map 10.6 **Map of SDAC member status in November 2020**



Source: All NEMOs Committee Secretariat

In the roadmap of SDAC implementation the **4MMC project** was selected as an interim solution servicing Czech, Slovak, Hungarian and Romanian market areas introducing the benefits of market integration to market participants using the stepwise market integration. 4MMC, which was launched in 2014 and acted as a preparation vehicle for the respective electricity markets of the Czech republic, Slovakia, **Romania and Hungary** for joining the Single Day-Ahead Coupling by implementing solutions according to regulation CACM. In SE Europe, as of July 2021, sixorganized electricity markets are fully coupled with the MRC and participate in SDAC, namely Slovenia (2015), Croatia (2018), Greece (2020) and Bulgaria (2021), Romania (2021) and Hungary (2021).

More specifically, the 4MMC project is expected to be fully integrated in SDAC, with its coupling with MRC and Poland by introducing NTC-based implicit allocation in 6 borders (PL-DE, PL-CZ, PL-SK, CZ-DE, CZ-AT, and HU-AT). The coupling, the first phase of which went live on 17 June 2021, is expected to follow a stepwise transition from the NTC-based explicit allocation towards the flow-based implicit allocation which is to be implemented in the framework of the Core Flow-Based Market Coupling Project as the target solution required by regulation.

The Republic of **Bulgaria** became a full member of SDAC by joining MRC (Multi Regional Coupling) in isolated mode in January 2016 but is still not an operational party in the project for objective reasons due to the specific characteristics of neighboring market areas. In particular, Bulgaria is anticipating (a) the merger of MRC with the market union 4MMC, of which neighboring Romania is part, and (b) the implementation of the target model and the expansion of MRC in Greece. The extension of SDAC to Bulgaria went live on 11 May 2021 via the Greek-Bulgarian interconnector[98].

Market coupling in the Intraday framework

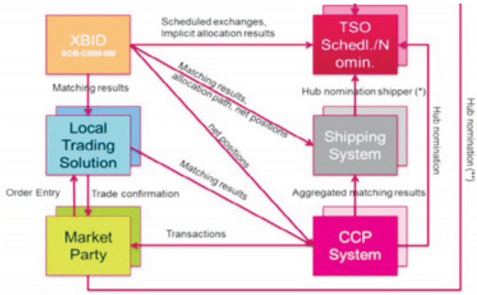
Currently, the project for the creation of a single pan-European coupled integrated intraday cross-border market is implemented by the XBID programme, which started as a joint initiative by Power Exchanges and Transmission System Operators (TSOs) from 11 countries, towards this goal. The XBID Platform has been confirmed as the Single Intraday Coupling (SIDC), which shall enable continuous cross-border trading across Europe. SIDC is based on a common IT system with one Shared Order Book (SOB), a Capacity Management Module (CMM) and a Shipping Module (SM).

This means that orders entered by market participants for continuous matching in one country can be matched by orders similarly submitted by market participants in any other country within the project's reach, as long as transmission capacity is available. The intraday solution supports both explicit (where requested by NRAs[99]) and implicit continuous trading and is in line with the EU Target model for an integrated intraday market. The purpose of the SIDC initiative is to increase the overall efficiency of intraday trading[100].

[98] https://www.enexgroup.gr/documents/20126/403136/20210309+SDAC+press+release+announcing+BG-GR+go-live.pdf
https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52018SC0376&from=EN
[99] National Regulatory Authorities
[100] https://hupx.hu/uploads/Kereskedes/Keresked%C3%A9si%20rendszer/ID/SIDC_Information%20Package_April%202021_FINAL.pdf

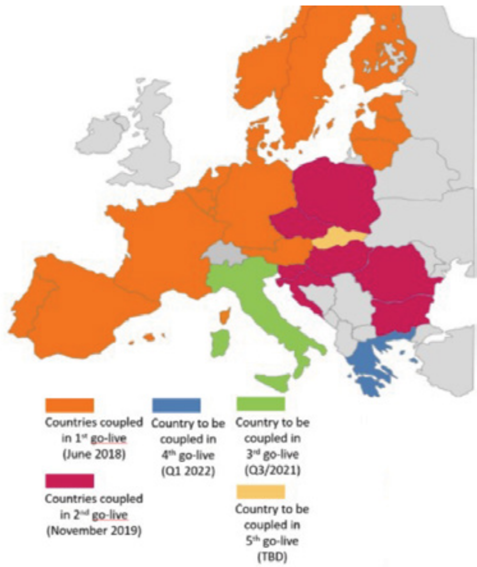
10

Figure 10.54 **Single Intraday Coupling (SIDC) architecture**



Source: SDIC

Map 10.7 **Map of SIDC waves of integration**



Source: Entso-e [101]

The implementation of SIDC is anticipated in a rollout of 5 waves as seen in Map 10.7. Currently the two first waves of the SIDC project have been rolled out. The first wave went live on 13th June 2018 and included the intraday markets of 15 countries (Spain, Portugal, France, Netherlands, Belgium, Germany, Luxemburg, Denmark, Sweden, Norway, Austria, Finland, Estonia, Latvia and Lithuania).

The second go-live wave expanded SIDC to 7 more countries, including 5 markets in the SEE (Bulgaria, Croatia, Czech Republic, Hungary, Poland, Romania and Slovenia). A third wave including Italy is foreseen for Quarter 3 of 2021, while Greece is expected to be integrated to SIDC in the fourth phase in Q1 of 2022.

Retail market

South East Europe is in an ongoing process of deregulation of electricity markets according to EU regulation, which besides the EU member states was also adopted by Energy Community Countries according to Directives 2003/54/EC and 2003/55/EC. Specifically according to Annex I of 2003/55/EC all non-household customers shall be eligible to choose their own supplier as from 1 January 2008, and all customers as from 1 January 2015. The right of eligibility allows customers to choose their supplier freely and without legal restrictions. Regulated tariffs can remain intact according to the state of competition of each domestic market but the eligible customers should be able to freely negotiate the prices with their suppliers.

Deregulation of the electricity supply has been finalized in EU member states but is far behind in the Energy Community contracting parties. According to Energy Community secretariat: ".. despite the commenced liberalization of the electricity sector, and formally opening the markets in line with the Directive's requirements, most of the Contracting Parties define tariff customers (as opposed to nontariff customers or "eligible" customers) as a group of customers – usually the large majority – for which they maintain regulated end-user prices. This group of tariff customers generally consists of not only household consumers and small businesses, but also medium to large-size business and even energy-intensive industries. In some jurisdictions, transitional periods for phasing-out of price regulation are envisaged. [102]

[101] https://www.entsoe.eu/network_codes/cacm/implementation/sidc/
[102] https://www.energy-community.org/legal/acquis.html

Moreover, electricity market observations indicate that prices remain partly regulated in Western Balkan countries as prices for only a relatively moderate portion of the market's volume are set exclusively by supply and demand. However, 2018 saw significant changes towards retail market opening in Bosnia and Herzegovina and North Macedonia, where the total supply, which was provided in the open market reached 45% and 97% respectively, from 16% and 23% in 2017.

Moreover, the retail market in North Macedonia is fully liberalized as of July 2019, following adoption of the necessary implementing acts of the new Energy Law that grants the eligibility right to all customers, repealing the possibility to deny any customer the right to choose their supplier. The retail electricity market opening has rather stalled in Albania, where the share of eligible customers remains below 20%, currently standing at 18% (2019).

Montenegro is gradually increasing its eligible customers with consumers corresponding to more than 40% of the total final demand, having access to the right of eligibility for the first time in 2018. Serbia's share of eligible customers, as to the total electricity demand of the country rose at 55%, from 49% in 2018.

In Kosovo, the regulator amended a Guideline on liberalisation of the electricity market, in order to prolong regulation of supply prices, by 31 March 2020 for customers supplied at a 35 kV voltage level, and by 31 March 2021 for 10 kV customers.

The following is a summary of the retail electricity market status in SEE with respect to its liberalization and competition:

- The opening of the retail market in Albania and Kosovo has been delayed.
- Full deregulation of retail electricity prices exist in BiH, Montenegro and Serbia but competition that would potentially escalate developments for customer eligibility has yet to be developed, therefore retail market opening has progressing slowly in the above markets.
- In North Macedonia retail electricity prices for universal supply are determined through a competitive bidding procedure. As of July 2019, the retail market in North Macedonia is fully liberalized
- Nine countries in the region, i.e. Bulgaria, Greece, Romania, Hungary, Serbia, Croatia, Slovenia, North Macedonia and Turkey operate fully liberalized retail electricity markets.

According to Eurostat, the average retail electricity prices in SEE without taxes and levies have remained stable for household customers from Q1 2019 to Q1 2020 at 11.32 c€/kWh but increased slightly, by 1.49%, in comparison to Q1 2018.

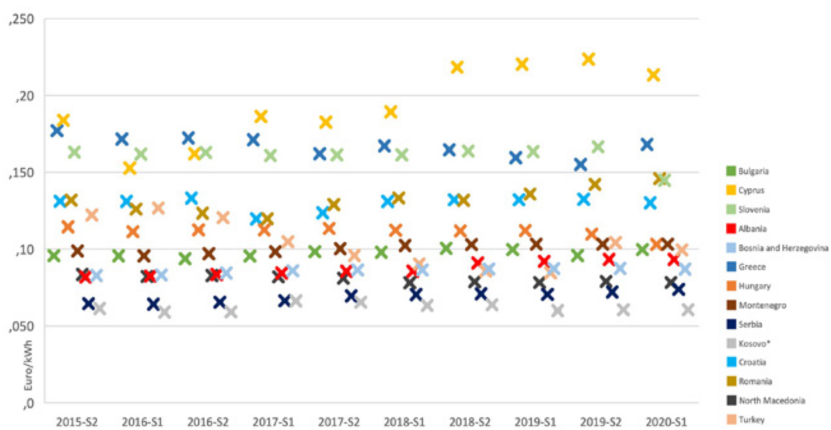
Retail Prices

Table 10.6 **Retail electricity price comparison across SEE in (€) without taxes and levies 2018-2020**

	Households ([1])			Difference [%] y-y	Difference [%] y-y	Non-households ([2])			Difference [%] y-y	Difference [%] y-y
	2018S1	2019S1	2020S1	2018-2019	2019-2020	2018S1	2019S1	2020S1	2018-2019	2019-2020
Greece	0.1672	0.1595	0.1681	-4.61%	5.39%	0.1038	0.1074	0.1079	3.47%	0.47%
Bulgaria	0.0979	0.0997	0.0997	1.84%	0.00%	0.0810	0.0887	0.0816	9.51%	-8.00%
Croatia	0.1311	0.1321	0.1301	0.76%	-1.51%	0.0994	0.1034	0.1043	4.02%	0.87%
Cyprus	0.1893	0.2203	0.2133	16.38%	-3.18%	0.1405	0.1619	0.1448	15.23%	-10.56%
Hungary	0.1123	0.1120	0.1031	-0.27%	-7.95%	0.0840	0.0970	0.0995	15.48%	2.58%
Slovenia	0.1613	0.1634	0.1448	1.30%	-11.38%	0.0860	0.0959	0.0984	11.51%	2.61%
Romania	0.1333	0.1358	0.1459	1.88%	7.44%	0.0831	0.0972	0.1063	16.97%	9.36%
Montenegro	0.1024	0.1032	0.1032	0.78%	0.00%	0.0810	0.0868	0.1032	7.16%	18.89%
North Macedonia	0.0781	0.0783	0.0782	0.26%	-0.13%	0.0624	0.0687	0.0778	10.10%	13.25%
Albania	0.0920	0.0920	0.0920	0.00%	0.00%	0.1040	0.1040	0.1040	0.00%	0.00%
Serbia	0.0705	0.0706	0.0738	0.14%	4.53%	0.0704	0.0833	0.0814	18.32%	-2.28%
Turkey	0.0904	0.0847	0.0995	-6.31%	17.47%	0.0589	0.0706	0.0799	19.86%	13.17%
Bosnia and Herzegovina	0.0864	0.0873	0.0870	1.04%	-0.34%	0.0661	0.0667	0.0734	0.91%	10.04%
Kosovo ([3])	0.0633	0.0600	0.0605	-5.21%	0.83%	0.0746	0.0660	0.0672	-11.53%	1.82%
Average	0.1125	0.1142	0.1142	1.49%	0.02%	0.0854	0.0927	0.0950	8.57%	2.47%

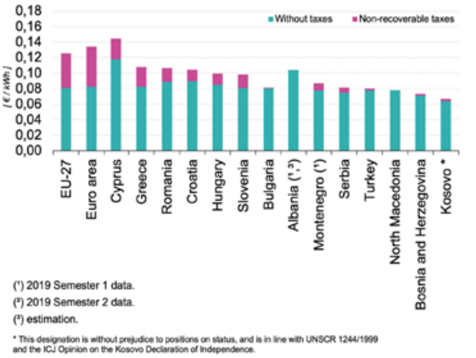
Retail prices for household consumers have on average remained relatively stable in SEE region. However, there is price volatility in various regional retail markets. Regional electricity markets that have exhibited reduced household retail prices in the last decade, i.e. 2015 – 2020 include Greece, Hungary, Slovenia, North Macedonia and Turkey, while a slight decline has also been present in household retail prices in Kosovo. On the other hand, significantly higher retail prices can be observed in Romania, Serbia Albania and Cyprus and to a lesser extent in Bulgaria and Bosnia and Herzegovina. The highest retail prices for residential consumers in the first semester of 2020 were in Cyprus and the lowest in Kosovo.

Figure 10.55 **Retail Electricity Prices for household consumers in SE Europe with taxes and levies - S2 2015 – S1 2021**



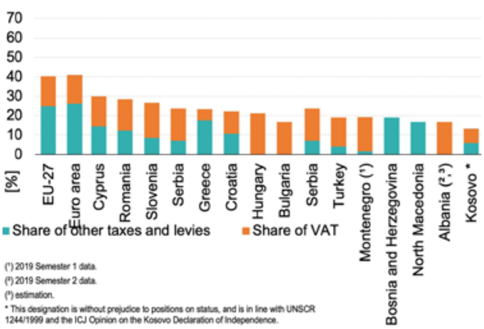
Source: Eurostat

Figure 10.56 **Electricity prices for household consumers in SEE, first half 2020 (EUR per kWh)**



Source: Eurostat

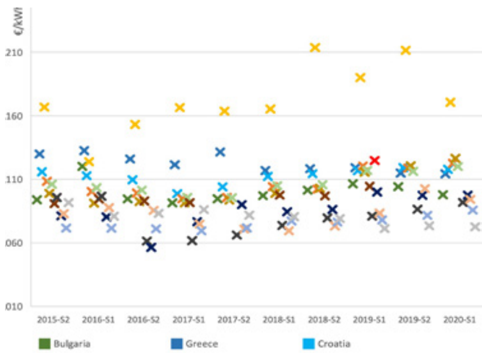
Figure 10.57 **Share of taxes and levies paid by household consumers for electricity, first half 2020 in SE Europe (%)**



Source: Eurostat

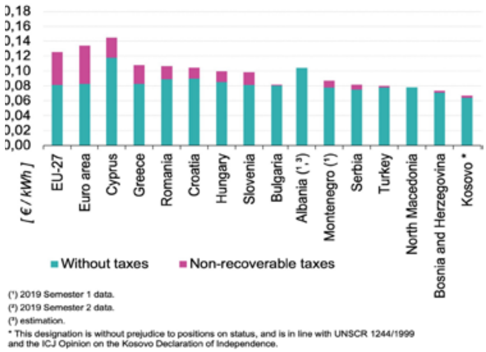
Retail prices for non-household consumers have on average increased in SEE region over the period 2015-2020. The price increase was impeded during 2017 primarily due to the reduced cost of generation especially in Romania, Hungary and Slovenia. Moreover, only North Macedonia, Greece and Kosovo saw non-household retail electricity prices decline in the specific period. The highest increases of retail prices for non-household consumers over the period of 2015-2020 were reported in Romania, Serbia and Bosnia and Herzegovina, where retail prices for medium volume consumers rose in the period of 2015-2020 by 27.91%, 20.05% and 19.67% respectively.

Figure 10.58 **Retail Electricity Prices for non-household consumers in SE Europe with taxes and levies - S2 2015 – S1 2021 (500 MWh/y < Consumption < 2000 MWh/y)**



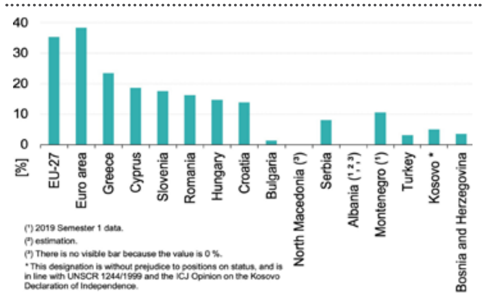
Source: Eurostat

Figure 10.59 **Electricity prices for non-household consumers, first half 2020 (EUR per kWh)**



Source: Eurostat

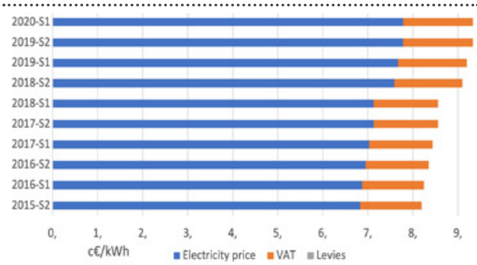
Figure 10.60 **Share of taxes and levies paid by non-household consumers for electricity, first half 2020 (%)**



Source: Eurostat

Albania: The average retail electricity price for household consumers in Albania accounted for 9.33 c€/kWh in S1 2020, rising constantly at a low rate since 2015. The electricity price in S1 of 2020 consisted of 83.39% related to electricity supply cost and network fees and 16.61% in taxes. The electricity retail price for household consumers stood in S1 of 2020, the highest it had been in the period 2015 -2020 partly as a result of reduced hydro reserves in domestic reservoirs due to a period of drought starting from Autumn of 2018 and lasting throughout 2019. Moreover, the extensive drought pushed the volume of imported electricity high in the second semester of 2018. Indicatively, in the first semester of 2018 Albania was a net exporter of electricity, recording net exports of 2.06 TWh while in the second semester of 2018, when the drought took hold, it turned into a net importer, recording net imports of 231.3 GWh[103].Therefore, Albanian retail electricity prices from S2 of 2018 onwards were highly exposed to cross border electricity trade prices.

Figure 10.61 **Decomposition of Retail electricity prices for household consumers Albania for S2 2015- S1 2020**

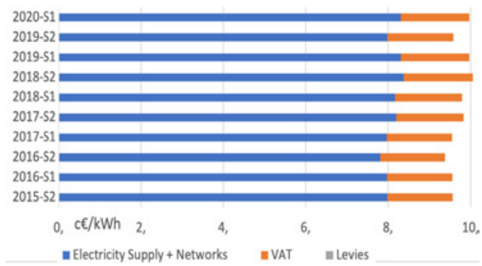


Source: Eurostat

In Albania, according to estimates by Eurostat, the retail prices in the segment of non-household consumers with consumption between 500 MWh – 2000 MWh annually, were approximately 12.48 c€/kWh in S1 of 2019, and consisted of 83.33% of electricity cost and network fees and 10.94% taxes.

Bulgaria: The household price in Bulgaria stood at 9.97 c€/kWh in S1 2020 according to Eurostat. The price was composed by 83.35% matching the electricity supply cost and the network fees while the rest, i.e. 16.65%, were taxes. The household price exhibited an increase of 4.18% in the past five years, i.e. in the period S2 2015 – S1 2020, while the highest price was observed on S2 2018, when the average retail electricity price for the household consumers price rose to 10.05 c€/kWh.

Figure 10.62 **Decomposition of Retail electricity prices for household consumers in Bulgaria for S2 2015- S1 2020**



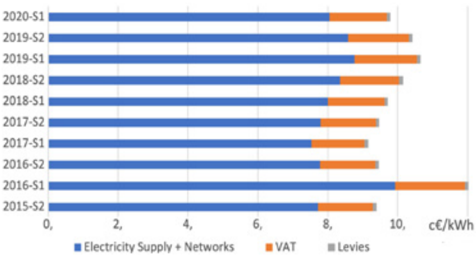
Source: Eurostat

Regarding the non-household consumers with average consumption between 500 MWh and 2 000 MWh annually, the average retail electricity price stood slightly lower at 9.79 c€/kWh in S1 2020. The retail price was constructed by 82.23% being the value of electricity and network costs, 16.65% being tax (VAT) and the remainder 1.12% being levies. The retail prices for commercial and industrial consumers were highly variable during the period 2015 – 2020.

More specifically, the price spiked marking the highest average price on a semester level for the period 2015 – 2020 on S1 of 2016, reaching 12.02 c€/kWh primarily driven by high wholesale prices, falling significantly the next semester below 9.5 c€/kWh, only to rise again above 10.5 on S1 of 2019 and then to gradually recede again to below 10 c€/kWh. Overall, retail electricity prices for medium volume non-household consumers grew over the period of 2015 -2020 by 4.26% based on the standing price of 9.79 c€/kWh on S1 2020.

[103] Source: ERE Annual report 2018 (Statistics xlsx)

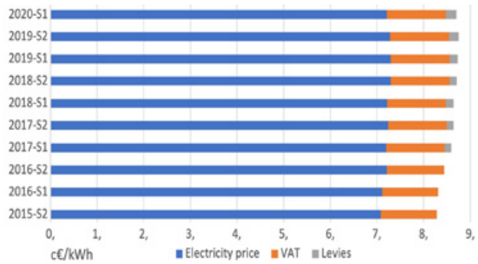
Figure 10.63 **Decomposition of Retail electricity prices for non-household consumers in Bulgaria for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



Source: Eurostat At retail level, there are three active suppliers which provide the total electricity supply in Bulgaria to the end consumers. CEZ Distribution Bulgaria AD serviced 39.68% of Bulgaria's total electricity supply, EVN Bulgaria Electricity Supply EAD the 38.26% and Energo-Pro Sales AD 22.81%. The total number of customers connected to the distribution companies in 2019 was 5,136,361, of which the household customers were 4,512,126. The total number of customers with an end supplier was 5,016,086, which represents 97.66% of all customers. The total number of customers in the free market, including the supplier of last resort (SLR), was 120,275[104].

Bosnia and Herzegovina: The average retail electricity price for household consumers in BiH accounted for 8.7 c€/kWh in S1 2020, declining slightly from S2 2019, but remaining at a relatively higher level than in 2015. The electricity price in S1 of 2020 was composed by 82.87% corresponding to electricity supply cost and network fees, 14.6% taxes and 2.53% levies. The electricity retail price for household consumers in S2 of 2019 stood at the highest point during the period 2015 -2020, at 8.75 c€/kWh driven by a slight increase in levies, which jumped at 0.2 c€/kWh from 0.17 c€/kWh a semester prior, while the pure cost of energy including transmission fees remained on a relatively high level. Overall retail electricity prices for household consumers are viewed rising constantly at a low rate varying between 0.6% - 1.8% semester-to-semester since 2015.

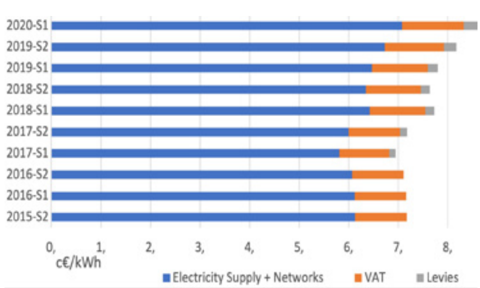
Figure 10.64 **Decomposition of Retail electricity prices for household consumers Bosnia and Herzegovina for S2 2015- S1 2020**



Source: Eurostat

In Bosnia and Herzegovina retail electricity prices for non-household consumers followed the regional trend and increased over the last five years to an average of 8.58 c€/kWh in S1 of 2020, i.e 19.67% higher than it was on S2 of 2015. The price consisted of 82.52% of electricity cost and network fees, 14.45% taxes and 3.30% levies. It is notable to mention the BiH introduced levies in the retail price for non-household consumers on S1 of 2017, which however did not affect the price significantly as their share to the price was low (1.87%) and at the same period lower wholesale electricity prices drove retail prices down.

Figure 10.65 **Decomposition of Retail electricity prices for non-household consumers in Bosnia and Herzegobina for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)

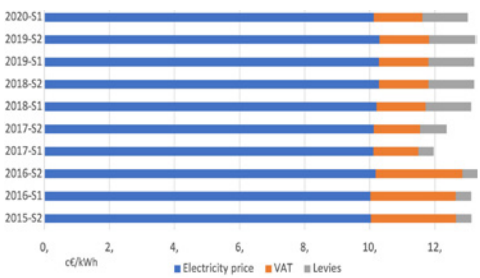


Source: Eurostat

[104] https://www.dker.bg/uploads/2020/report_EC_2020_EN.pdf

Croatia: The average household retail electricity price in Croatia reached at 13.01 c€/kWh in S1 2020. The price was composed by a 77.79% being the electricity supply cost and the network fees, 11.53% were taxes (VAT) and the rest i.e. 10.68% were levies. The average retail household price exhibited a marginal decline of 0.84% between S2 2019 and S1 2020, after gradually increasing over the period 2015-2019. The decline was only marginal and can be attributed to a reduction of generation and network costs. The highest average retail price in Croatia over the period 2015 – 2020 which was observed in S2 2019, reached 13.24 c€/kWh.

Figure 10.66 **Decomposition of Retail electricity prices for household consumers in Croatia for S2 2015- S1 2020**

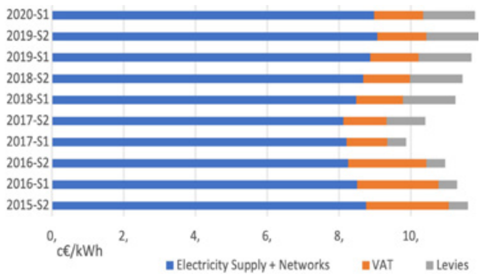


Source: Eurostat

Regarding the non-household consumers with average consumption between 500 MWh and 2 000 MWh annually, the average retail electricity price stood slightly lower at 11.79 c€/kWh in S1 2020 than it was the previous semester. The retail price was constructed by 76.17% being the value of electricity and network costs, 11.54% being tax (VAT) and the remainder 12.30% being levies.

The retail prices for commercial and industrial consumers remained above 11 c€/kWh throughout the five-year period, except a decline recorded during 2017 when they formed at 9.87 c€/kWh and 10.4 c€/kWh for S1 and S2 of the specific year respectively. Overall retail prices for non-household consumers rose by 1.73% in Croatia during 2015-2020.

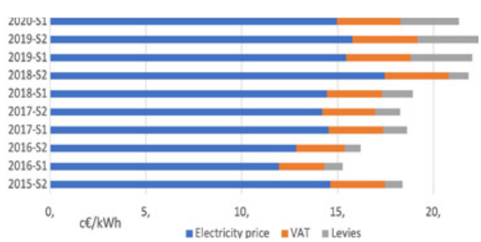
Figure 10.67 **Decomposition of Retail electricity prices for non-household consumers in Croatia for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



Source: Eurostat

Cyprus: The average household retail electricity price in Cyprus reached at 21.33 c€/kWh in S1 2020, which was the highest in the region as a result of high generation costs from the oil-dominant electricity mix of Cyprus. The price was largely composed by a 70.18% component which corresponded to the electricity supply cost and the network fees, 15.52% corresponded to taxes (VAT) and the rest i.e. 14.30% were levies. The household retail price exhibited an increase of 16.05% in the past five years, i.e. in the period S2 2015 – S1 2020, while the highest retail price for the household consumers price was observed on S2 2019, when it stood at 22.36 c€/kWh.

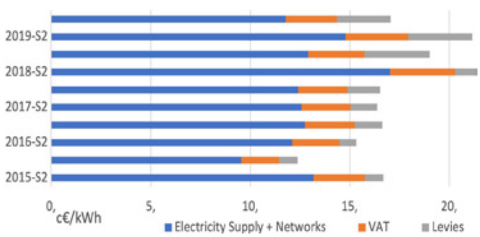
Figure 10.68 **Decomposition of Retail electricity prices for household consumers in Cyprus for S2 2015- S1 2020**



Source: Eurostat

Cyprus retains the highest prices in retail electricity markets also in the non-household segment, with its retail prices being heavily exposed to oil prices. Therefore, we observe that the lowest price formed in the Cyprus market during the last decade was during the oil price slump in the first semester of 2016, when oil prices fell momentarily below $30 a barrel, dragging the retail electricity prices in Cyprus in the same period to a 5-year low 12.38 c€/kWh. Currently (S1 2020) the price stands at 17.06 c€/kWh. Moreover, the average retail price for non-household consumers as it was on S1 2020, consisted of 69.05% of the value of electricity and network costs, 15.12% VAT and 15.83% levies.

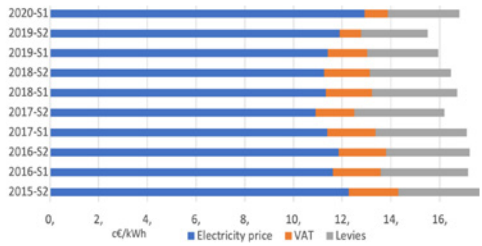
Figure 10.69 **Decomposition of Retail electricity prices for non-household consumers in Cyprus for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



Source: Eurostat

Greece: The average household retail electricity price in Greece was formed at 16.81 c€/kWh in S1 2020 based on data provided by Eurostat. The price was composed by a 76.86% being the electricity supply cost and the network fees, 5.65% were taxes and the rest i.e. 17.49% were levies. The average retail household price exhibited a decline of 5.08% in the past five years, i.e. in the period S2 2015 – S1 2020, with prices gradually falling from the highest price in the specific period which was recorded in S2 of 2015, at 17.71 c€/kWh.The decline came as a result of the reduction of VAT for electricity in the second semester of 2019, and the gradual decline of levies since semester 1 of 2017, when they peaked at 3.75 c€/MWh. It is notable that average levies in the residential bills recovered in the first semester of 2021 as a result of new attributed value of SGIs which rose from 6.99 - 44.88 c€/kWh to 6.9 – 85 c€/kWh[105], slightly favoring low volume consumers but passing on higher costs to medium and large ones. As a result, overall levies in the average residential bill rose by 2 c€/kWh.

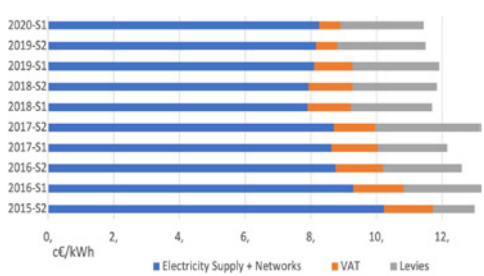
Figure 10.70 **Decomposition of Retail electricity prices for household consumers in Greece for S2 2015- S1 2020**



Source: Eurostat

In Greece the retail prices for non-household consumers with average consumption between 500 MWh and 2 000 MWh annually receded in the second semester of 2019 and the first semester of 2020, after remaining relatively stable during 2018 and during the first half of 2019. Observing the broader price developments of the period 2015 -2020, retail prices from non-household consumers receded significantly after peaking in S2 of 2017, at 13.15 c€/kWh, which was the highest over the five-year period. The average retail price for medium size non-household consumers was formed at 11.43 c€/kWh in S1 of 2020. The price was made up by 82.23% of the value of electricity and network fees, 16.65% VAT and 1.12% levies. Moreover, taxes and levies remained relatively stable percentage-wise throughout 2015-2020.

Figure 10.71 **Decomposition of Retail electricity prices for non-household consumers in Greece for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)

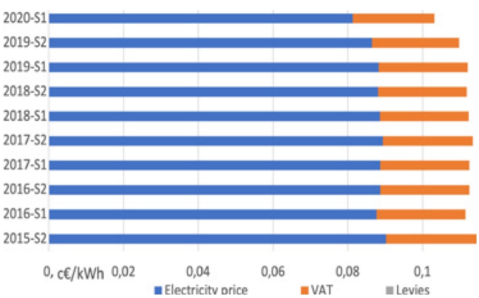


Source: Eurostat

[105] https://www.energycost.gr/en/adjustable-charges/electricity-energy

Hungary: The average household retail electricity price in Hungary reached 10.31 c€/kWh in S1 2020, following a constant decline since S2 2017. The price was composed by 78.76% electricity supply cost and network fees and the rest i.e. 21.24% were taxes (VAT). The household retail price exhibited a decline of 9.96% in the past five years, i.e. in the period S2 2015 – S1 2020, while the highest retail price for the household consumers price was observed on S2 2017, when it stood at 11.23 c€/kWh. Moreover, taxation has not change over the last five years and levies do not apply in the residential consumer electricity bills. Therefore, retail prices are fully exposed to generation and network costs and retail pricing regimes in the open market.

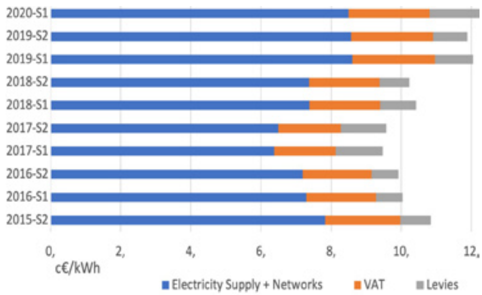
Figure 10.72 **Decomposition of Retail electricity prices for household consumers in Hungary for S2 2015- S1 2020**



Source: Eurostat

In Hungary non-household consumers saw a price increase in their retail electricity bills over the last 5 years, with prices rising by 13.10% in S1 2020 compared to what it was on S2 of 2015. The price rise started on S2 of 2017 after recording two years of decline. The average retail electricity price for non-household consumers reached 12.26 c€/kWh on S1 2020, the highest value over the period 2015-2020. The price consisted 69.25% of electricity and network costs, 18.84% taxes and 11.91% levies.

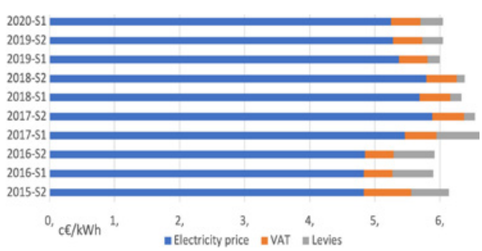
Figure 10.73 **Decomposition of Retail electricity prices for non-household consumers in Hungary for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y



Source: Eurostat

Kosovo[106]: The average retail electricity price for household consumers in Kosovo accounted for 6.05 c€/kWh in S1 2020, remaining relatively stable since semester 1 of 2019, when prices declined by approximately 6%. The electricity price in S1 of 2020 was composed by 86.78% corresponding to electricity supply cost and network fees, 7.44% taxes and 5.79% levies. The electricity retail price for household consumers in S1 of 2017 stood at the highest point during the period 2015 -2020, at 6.62 c€/kWh driven by a higher wholesale electricity prices and relatively high levies at 0.67 c€/kWh. More specifically levies charged for residential consumers accounted for 9.5% to 10.5% of the total retail electricity price up until S2 of 2017, when it fell to 10%, dragging prices slightly downwards.

Figure 10.74 **Decomposition of Retail electricity prices for household consumers Kosovo for S2 2015- S1 2020**

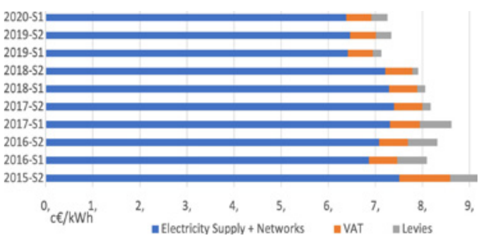


Source: Eurostat

[106] Under United Nations Security Council Resolution 1244/99

Kosovo along with North Macedonia were the only markets that saw retail prices for non-household consumers dropping over the period 2015-2020, with the price drop in the case of Kosovo beingof a more significant magnitude. More specifically, the average price in S1 2020 stood at 7.26 c€/kWh i.e 20.83% lower than it was on S2 of 2015. The price consisted of 89.88% electricity cost and transmission and distribution fees, 7.44% taxes and 4.68% levies. Part of the decline was the significant reduction of taxes and levies in the share of electricity price over the years. Indicatively, taxes stood at 11.78% and levies at 6.32% of the total retail price for non-household consumers in 2015 approximately 50% higher than in 2020.

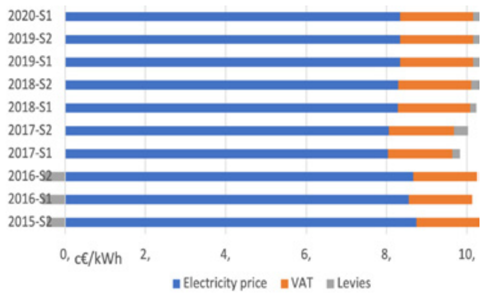
Figure 10.75 **Decomposition of Retail electricity prices for non-household consumers in Kosovo for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



Source: Eurostat

Montenegro: The average household retail electricity price in Montenegro accounted for 10.32 c€/kWh in S1 2019, slightly higher since 2015. The electricity price was composed by 80.81% of electricity supply cost and network fees and 19.19% taxes and levies. The electricity retail price for household consumers presented an increase by 4.45% over the past five years, i.e. in the period S2 2015 – S1 2020, while the highest average retail price for the Montenegrin household consumers was the last recorded price of 10.32 c€/kWh, which stood in semester 1 of 2019. A notable increase of retail prices for Montenegrin household consumers in 2017 can be attributed to an increase in taxes and levies which moved from the range of 1 – 1.14 c€/kWh to 1.79 – 2.01 c€/kWh, currently standing at 1.98 c€/kWh.

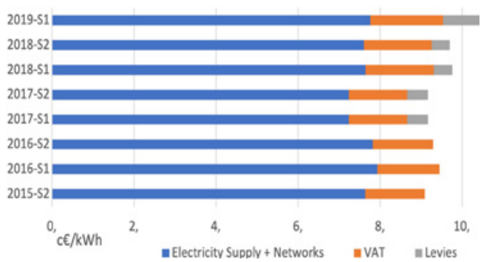
Figure 10.76 **Decomposition of Retail electricity prices for household consumers Montenegro for S2 2015- S1 2020**



Source: Eurostat

Regarding the non-household-consumption in the specific market segment, retail prices followed an upward regional trend, reaching 10.45 c€/kWh on S1 of 2019, 14.96% higher than it was on S2 of 2015. The prices consisted of 74.26% of electricity cost and network fees, 16.94% taxes and 8.8% levies.

Figure 10.77 **Decomposition of Retail electricity prices for non-household consumers in Montenegro for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



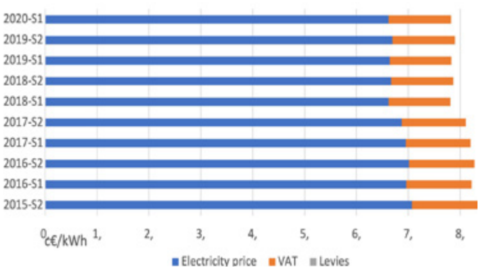
Source: Eurostat

[106] Under United Nations Security Council Resolution 1244/99

North Macedonia: The average retail electricity price for household consumers in North Macedonia accounted for 7.82 c€/kWh in S1 2020, remaining relatively stable since semester 1 of 2018 (last five semesters), since the retail electricity market was fully liberalized with the entirety of residential consumers having access to the open market. The electricity price in S1 of 2020 was composed by 84.65% of electricity supply cost and network fees and 15.35% taxes. No levies are charged in North Macedonia in electricity bills.

The electricity retail price for household consumers presented a decline by 6.35% over the past five years, i.e. in the period S2 2015 – S1 2020, while the highest average retail price for household consumers in North Macedonia for the same period was 6.62 c€/kWh, and appeared in the first semester of 2017. Moreover, after retail electricity market liberalization in the first semester of 2018 we observe a decline of electricity prices falling as much as 6% (s-s) in the S1 of 2019, when it reached the lowest average price of the last three years (2017 -2020), at 6 c€/kWh.

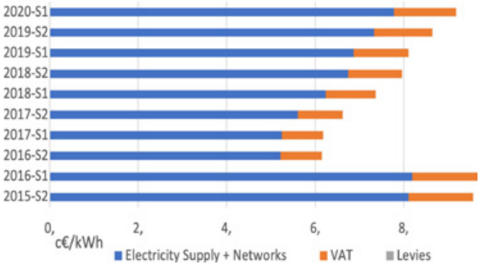
Figure 10.78 **Decomposition of Retail electricity prices for household consumers North Macedonia for S2 2015- S1 2020**



Source: Eurostat

Despite the full liberalization of the electricity market in 2018, North Macedonia saw its domestic retail electricity prices for non-household consumers rising since 2017, following the regional trend which was driven by higher generation costs. However, relatively high regulated prices in the period 2015-2016 led to an overall decline of retail electricity prices in the non-household section of demand, with prices falling S1 of 2020 by 3.97% lower than it was in S2 2015. The average retail price reached 9.19 c€/kWh, and consisted 84.66% of electricity cost and network fees and 15.34% taxes.

Figure 10.79 **Decomposition of Retail electricity prices for non-household consumers in North Macedonia for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



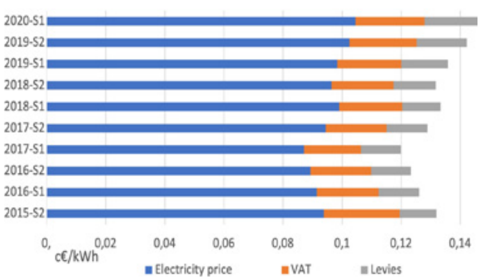
Source: Eurostat

The overall percentage of electricity consumption, as provided in the open market of electricity in 2019 in North Macedonia, was 49,13 %. This percentage includes the electricity required to cover losses of electricity within the Electricity Transmission Grid, i.e., of the Electricity Distribution Grids. The share of electricity provided in the open liberalized market grew in 2019 as compared to 2018, when it stood at 47.48 %. It is notable that as the unbundling and the opening of retail electricity market is taking hold, household consumers were for the first time able to choose their own provider, a development which boosted the number of customers switching electricity supplier in 2019 to 7,231 , 0.83% of the total electricity customers in North Macedonia. Therefore, the increase of customers switching supplier rose by 66,46 % compared to 2018, when they stood at 4,344.

Romania: The average household retail electricity price in Romania reached 14.59 c€/kWh in S1 2020, rising constantly since S1 of 2017. The electricity price was composed by 71.62% of electricity supply cost and the network fees, 15.97% were taxes (VAT) and the rest i.e. 12.41% being levies.

The household retail price exhibited an increase of 10.61% in the past five years, i.e. in the period S2 2015 – S1 2020, while the highest retail price for the household consumers was the last recorded price in S1 2020, when it stood at 14.59 c€/kWh. Romania saw a decline in electricity bill taxes in the period 2015 – 2017, with the VAT falling from 19.41% on S2 2015 to 15.98% on S2 2017, where it remained until present. Moreover, levies have been increasing gradually since recording their minimum at 1.3 c€/kWh (or 9.75% of the retail price) in S1 of 2018. Retail prices have been negatively affected by the phasing out of the obligation of electricity producers to sell to last resort suppliers at regulated tariffs to ensure household consumption. This obligation was still covering 75% of household electricity demand in the S1 of 2020, and is set to drop to 60% for S2 before abolished in 2022.

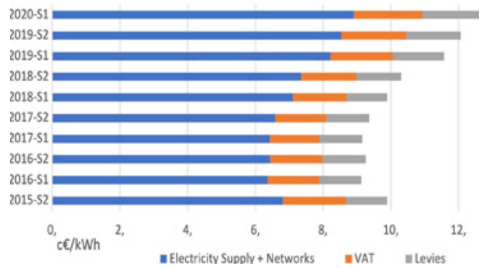
Figure 10.80 **Decomposition of Retail electricity prices for household consumers in Romania for S2 2015- S1 2020**



Source: Eurostat

Romania has also seen the retail prices for its domestic non-household consumers with average consumption between 500 MWh and 2 000 MWh annually rising, notably over the period 2015-2020. The highest price on a semester level was in S1 of 2020 at 12.65 c€/kWh, which stands higher than the average price of S2 of 2015 by 13.1%. The price was composed of 70.36% electricity and network costs, 15.97% taxes and 13.68% levies.

Figure 10.81 **Decomposition of Retail electricity prices for non-household consumers in Romania for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)

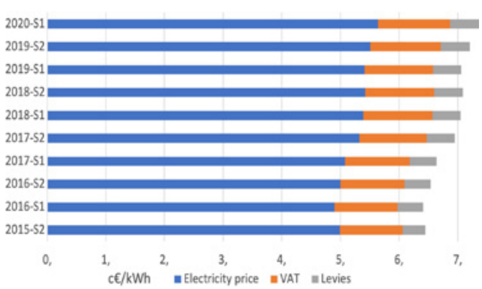


Source: Eurostat

Serbia: The average retail electricity price for household consumers in Serbia accounted for 7.38 c€/kWh in S1 2020, rising constantly at a low rate since 2016. The electricity price in S1 of 2020 was composed of a 76.42% corresponding to electricity supply cost and network fees, 16.67% taxes and 6.91% levies.

The electricity retail price for household consumers stood in S1 of 2020 at the highest level it had been in the period 2015 -2020, primarily as a result of increased generation costs over time that were passed on retail prices. We also observe a gradual increase in taxes and levies from a combined participation in the total retail price of 22.64% in S2 of 2015 to 23.56% in S1 of 2016, which remained at similar levels until today.

Figure 10.82 **Decomposition of Retail electricity prices for household consumers Serbia for S2 2015- S1 2020**

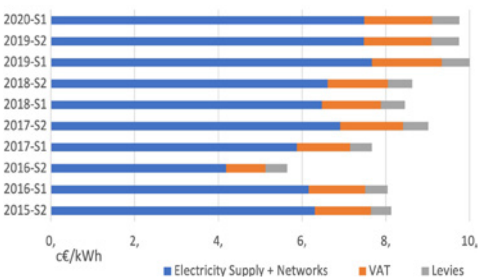


Source: Eurostat

10

Serbia saw electricity price stabilization for its non-household consumers, which remained marginally unchanged between S2 of 2019 and S1 of 2020, while it declined slightly since S1 of 2019. The lowest retail price for the specific segment in Serbia over the last 5 years was achieved on S1 of 2017 at 7.48 c€/kWh and the highest on S1 of 2019 at 10 c€/kWh. In S1 of 2020 the average retail price for non-household consumers stood at 9.76 c€/kWh and consisted of 76.64% electricity cost and network fees, 16.60% taxes and 6.76% levies. Overall electricity prices for the non-household segment increased by 20.05% since S1 of 2015.

Figure 10.83 **Decomposition of Retail electricity prices for non-household consumers in Serbia for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



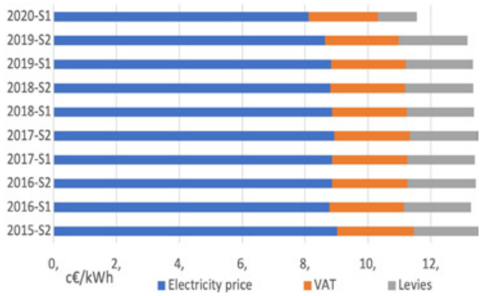
Source: Eurostat

Slovenia: The average household retail electricity price in Slovenia reached 14.48 c€/kWh in S1 2020, falling sharply, by 13.09%, in comparison to the previous semester, i.e. S2 of 2019. The electricity price was composed of 73.41% of electricity supply costs and network fees, 18.02% taxes (VAT) and 12.41% levies.

The electricity retail price for the residential sector exhibited a decline by 11.22% in the past five years, i.e. in the period S2 2015 – S1 2020, while the highest retail price for the household consumers price was the last recorded price in S2 2019, when it stood at 16.66 c€/kWh.

The sharp decline of retail prices in Slovenia in 2020 can be attributed to the decline of the cost of taxes and levies in the electricity bills, which was reduced from approximately 2.14 -2.19 c€/kWh, which was mostly during the previous years, to 1.24 c€/kWh in S1 of 2020.

Figure 10.84 **Decomposition of Retail electricity prices for household consumers Slovenia for S2 2015- S1 2020**

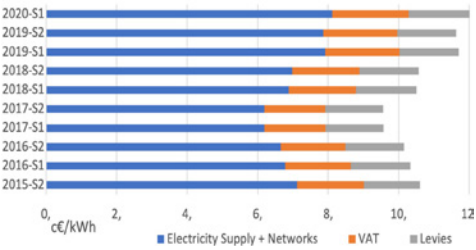


Source: Eurostat

In Slovenia we observed the same trend in non-household retail prices as seen in Hungary and Romania. Even though Slovenia was not coupled with the 4MMC markets of Romania and Hungary, being coupled to MRC since 2015, its wholesale prices followed the regional trend exhibited by Central European markets and 4MMC markets. Consequently, this is reflected on the retail price level for commercial industrial consumers.

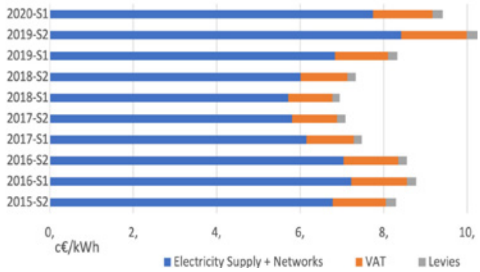
Prices followed the regional trend falling during 2017 but rising steadily up to the peak of 5-year period at 12.01 c€/kWh in S1 of 2021. Moreover, the price was formed by 67.53% of electricity and networks costs, 18.07% taxes and 14.40% levies. The retail prices for non-household consumers rose in Slovenia by 13.2% compared to the levels they were in S2 of 2015.

Figure 10.85 **Decomposition of Retail electricity prices for non-household consumers in Slovenia for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



Source: Eurostat

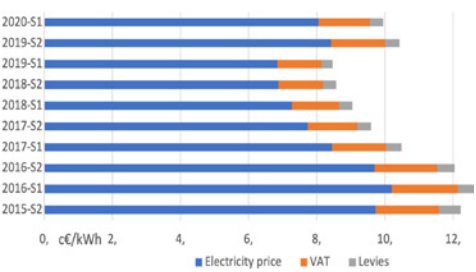
Figure 10.87 **Decomposition of Retail electricity prices for non-household consumers in Turkey for S2 2015- S1 2020** (500 MWh/y < Consumption < 2000 MWh/y)



Source: Eurostat

Turkey: The average retail electricity price for household consumers in Turkey accounted for 9.95 c€/kWh in S1 2020, declining slightly from S2 2019, when it peaked along a period more than 2.5 years. The electricity price in S1 of 2020 was composed by 80.90% corresponding to electricity supply cost and network fees, 15.18% taxes and 3.92% levies. The electricity retail price for household consumers stood on S1 of 2016 at the highest level recorded in the period 2015 -2020, at 12.67 c€/kWh, driven by high seasonal wholesale prices as compared to the last 5 years, at 10.2 c€/kWh. Retail price development also reflects comparatively high generation and transmission costs for the latter half of 2019, onwards.

Figure 10.86 **Decomposition of Retail electricity prices for household consumers Turkey for S2 2015- S1 2020**



Source: Eurostat

In Turkey, retail prices for non-household consumers increased overall for the span of 5 years rising at 9.42 c€/kWh in S1 of 2020, having increased by 13.63% since S2 of 2015. Moreover, the prices consisted of 82.17% of electricity costs and network fees, 15.18% taxes (VAT) and 2.65 levies.

10

10.7 Electric vehicles in SE Europe

Electrification of on-road transport through the wide adoption of Electric Vehicles (EVs) has been a priority for the EU since 2016, when the European Commission in the aftermath of the Paris Climate accord published the "European strategy for low-emission mobility"[107]. In this document, the adoption challenges of EVs were widely reported and discussed. This strategy has rolled out a comprehensive action plan for the legislative support of EU member states towards the promotion of low carbon mobility[108]. Previously published directives have laid the foundation for this strategy, such as (a) the Directive 2014/94/EU "on the deployment of alternative fuels infrastructure"[109], which was the first document outlining technically potent solutions for the decarbonization of on-road transport by establishing a common framework of measures for the deployment of alternative fuels infrastructure and (b) the Directive 2009/33/EC "on the promotion of clean and energy-efficient road transport vehicles", which proposed for the first time market based economic incentives for low carbon intensive vehicles.

The comprehensive strategy of the EU towards the adoption of low carbon intensive vehicles is currently enforced through the mandate for gradual CO_2 equivalent binding emission targets, for the entire fleet and for each manufacturer separately[110], described in EU Regulation 2019/631 "Setting CO_2 emission performance standards for new passenger cars and for new light commercial vehicles, and repealing Regulations (EC) No 443/2009 and (EU) No 510/2011" [111]. Through this legislative provision, from 2021, phased in from 2020, the EU fleet-wide average emission target for new cars is set at 95 g CO_2/km. This emission level corresponds to a fuel consumption of around 4.1 l/100 km of petrol or 3.6 l/100 km of diesel. Adoption of these limits have pushed the market towards EVs, as a large roll-out of competitive alternatives without the contribution of EVs to the emission average cannot help meet the above ambitious emission targets. This was verified by a number of scientific studies[112], which drove political mandates for the promotion of electric mobility[113]. As manufacturers and legislators have oriented towards electric mobility, a number of targets have been set for production and deployment regimes by various manufacturers and EU member states respectively.

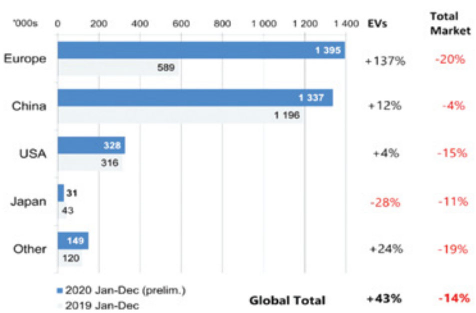
Although SEE numbers seven (7) EU member states (Croatia, Bulgaria, Cyprus, Greece, Hungary, Romania, Slovenia) the deployment of EVs had been stagnant until 2019 in most of the regional markets. This picture, however, is on a verge of sudden change with significant increase in market share for electric vehicles in SEE, with a major escalation of sales in 2020 despite the COVID-19 crisis. This can be attributed to the increased number of newly available EV models, which have been timely introduced in the European markets, as manufacturers rallied for developing and ramping up production of their battery electric vehicle (BEV) and plug-in hybrid electric vehicle (PHEV) models.

In a broader perspective, global sales of EVs accelerated in 2020, rising by 43% to more than 3 million vehicles, despite overall car sales declining significantly, i.e. by 20%, during the coronavirus pandemic. Sales of electric vehicles more than doubled in Europe, pushing it past China as the world's biggest market for electric mobility. Sales of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) made up 4.2% of the global

107 https://eur-lex.europa.eu/resource.html?uri=cellar:e44d3c21-531e-11e6-89bd-01aa75ed71a1.0002.02/DOC_1&format=PDF
108 https://eur-lex.europa.eu/resource.html?uri=cellar:e44d3c21-531e-11e6-89bd-01aa75ed71a1.0002.02/DOC_2&format=PDF
109 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32014L0094 currently (Jan 2021) in- force supplemented by COMMISSION DELEGATED REGULATION (EU) 2018/674: https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32018R0674&from=EN
110 https://ec.europa.eu/clima/policies/transport/vehicles/regulation_en
111 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0631&from=EN
112 Thiel C, Nijs W, Simoes S, Schmidt J, van Zyl A, Schmid E. The impact of the EU car CO2 regulation on the energy system and the role of electro-mobility to achieve transport decarbonisation. Energy Policy 2016;96:153–66. https://doi.org/10.1016/j.enpol.2016.05.043.
113 Transport & Environment. Commission Stands Firm on Electric Vehicle Mandate. 2017. Available online: https://www.transportenvironment.org/news/commission-stands-firm-electric-vehicle-mandate (accessed on 15 April 2020).

passenger car market, up from 2.5% in 2019. As in previous years, the rising EV sales were driven by government policies, deployed to promote electric mobility and to reduce the carbon footprint of transportation, as production cost parity of EVs with conventional-fueled cars has yet to be achieved.

Figure 10.88 **PEV sales (1,000 units) and PEV sales growth (%) in global motor vehicle markets**

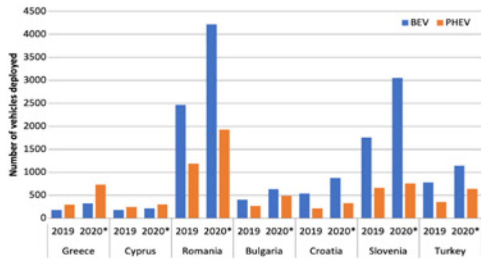


Source: EV-Volumes

Contrary to the sharp development of EV markets in Scandinavia, Central and West Europe, currently, the development of an EV market in SE Europe is at a nascent level, but it is expected to grow significantly over the next decades. In addition, the market share of PEVs in the selected SE European countries, as shown in Figure 10.90, averaged 0.54% in 2019, which is low, compared to European and global levels. More specifically, in 2019, the market share of PEVs in European and global car sales reached 3.5% and 2.6% respectively.

In terms of the share of BEVs and PHEVs registrations in SEE, it is notable that these are diversified and are driven by specific urban planning conditions and transport load particularities in each country. Most notably, regional markets with more developed EV charging network, such as Slovenia and Croatia, have seen a higher penetration of BEVs to their motor vehicle market. On the contrary, markets, such as Greece and Cyprus, which exhibit delays in the deployment of adequate EV charging infrastructure, have a more developed market for PHEVs. Currently, based on data published by EAFO for 2019 and 2020, the regional market size for PHEVs stands at approximately 50% of the market size of BEVs. Furthermore, 2020 has been a significant year for the sales of EVs in SE Europe, as the regional fleet rose by 65.4% during the period of January-October 2020.

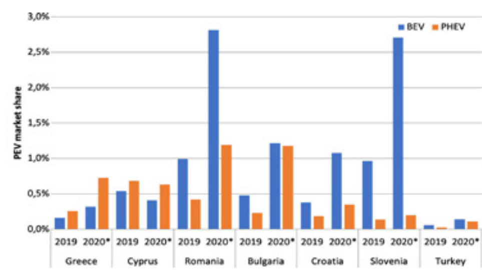
Figure 10.89 **PEV Fleet in Selected SEE Countries, 2019 and 2020***



Note: *Data available until October 2020

Source: EAFO

Figure 10.90 **PEV Market Share (%) in Selected SEE Countries, 2019 and 2020***



Note: *Data available until October 2020

Source: EAFO

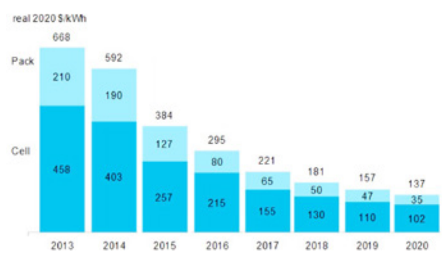
In the context of regional EV market expansion, there are several ongoing actions and initiatives which aim at promoting infrastructure development for EV charging in order to facilitate the expected EV market growth. Among these actions, one of the most important is the European project "Comprehensive fast-charging corridor network in SE Europe". This Action is the second phase of a Global Project aiming at deploying and operating a comprehensive multi-standard, open-access fast and ultra-fast charging corridor for electric vehicles

[114] EU+UK+EFTA+Turkey

in SE Europe. The Action will contribute to the implementation of National Action Plans for the deployment of alternative fuels infrastructure. The objective is to set up a multi-standard open-access fast charging network in Croatia and Romania. It covers 3 TEN-T corridors, namely the Mediterranean, Rhine-Danube and the Orient/East-Med Core Network corridors. During the Action, 69 multi-standard fast charging stations (50 kW DC and 22 Kw AC) will be deployed, 53 in Romania at 25 sites and 16 in Croatia at 6 sites. Furthermore, 4 ultra-fast charging stations (minimum 150 kW DC) will be deployed, 3 in Romania and 1 in Croatia. Charging stations will be powered by energy from renewable sources, such as wind or solar power.

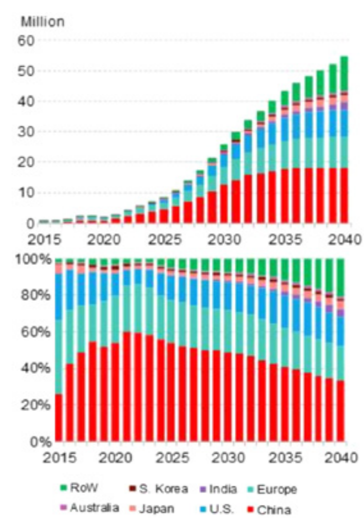
Based on data from the European Alternative Fuels Obervatory (EAFO), the automotive industry of the SE European region, mainly located in Turkey, Romania and Slovenia, has not yet made a significant turn to EV manufacturing. Figure 10.89 shows the number of Plug-in Electric Vehicles (PEVs), including BEVs and PHEVs, in selected SEE countries for 2019 and 2020, highlighting the nascent stage of their development. Indicatively, the total number of PEVs in SE Europe stood at 9,534 in 2019, when the total number of PEVs reached 1.75 million in Europe over the same year and exceeded 7.1 million globally. However, Turkey has made a significant first step for the regional development of the EV market. More specifically, in June 2018, the Anadolu Group, BMC, Kök Group, Turkcell and Zorlu Holding as well as an umbrella organization, the Union of Chambers and Commodity Exchanges of Turkey, joined forces to form Turkey's Automobile Joint Venture Group (TOGG) to produce the country's first domestically manufactured electric vehicle. By 2030, TOGG is anticipated to produce and own the intellectual and industrial property rights of five different electric vehicle (EV) models produced in Turkey – SUV, b-SUV, sedan, c-hatchback and b-MPV. Moreover, towards this direction, Turkey inaugurated the first Eti Maden Lithium Production Plant in the central province of Eskişehir in December 2020. Part of the lithium carbonate produced in the specific facility will be used in the production of batteries for TOGG's EVs.[115] Moreover, on a global scale, market analysts project that price parity of EVs and ICEs is drawing near. Most notably, BNEF's 2020 Battery Price Survey, which considers passenger EVs, e-buses, commercial EVs and stationary storage, predicts that by 2023 average battery pack prices will be $101/kWh. It is at around this price level that automakers should be able to produce and sell EVs globally and at the same price (and with the same margin) as comparable internal combustion vehicles in some markets. This estimation assumes no subsidies are available, but actual pricing strategies will vary by automaker and geography.

Figure 10.91 **Projections of volume-weighted average pack and cell price split ($/kWh)**



Source: BloombergNEF

Figure 10.92 **Projected (a) annual passenger EV sales by region (b) regional shares of annual passenger**



Source: BloombergNEF

[115] https://www.dailysabah.com/business/energy/electricity-demand-to-constitute-30-of-turkeys-energy-usage-by-2040-expert

Addendum

Gas and Electricity Prices in SE Europe in 2021

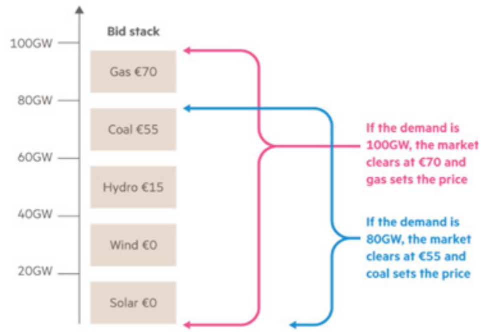
In 2021, the soaring cost of gas pushed up energy bills across Europe — and put the EU's electricity market under the spotlight. The way prices are set has come under fire not just from member states — with Spain and France leading calls for changes to protect consumers from surging costs — but from Russia, where President Vladimir Putin blames rising gas prices partly on the EU's decision to phase out long-term contracts in favour of market-based prices.

The European Commission, however, resisted pressure for major regulatory changes to the 30-year-old EU energy market. Brussels published a "toolbox" of options to deal with the price surge, such as direct income support and tax breaks but is staying away from promising a radical overhaul of pricing rules. Kadri Simson, EU energy commissioner, has defended the system for paving the way for market liberalisation and encouraging investment in green technologies.

Why is the Price of Electricity Rising?

The average European household electricity bill is broken down into costs for taxes and VAT (about 35%), network operator costs (30%), and the unit cost of energy (about 35%), according to figures from the EU's Agency for the Cooperation of Energy Regulators (ACER). At the heart of complaints from some countries is the EU's energy pricing system. It operates on a common "pay as you clear" model where wholesale electricity costs reflect the price of the last unit of energy bought via auctions held in member states.

Figure 10.93 **Marginal Pricing: Pay-as-clear**



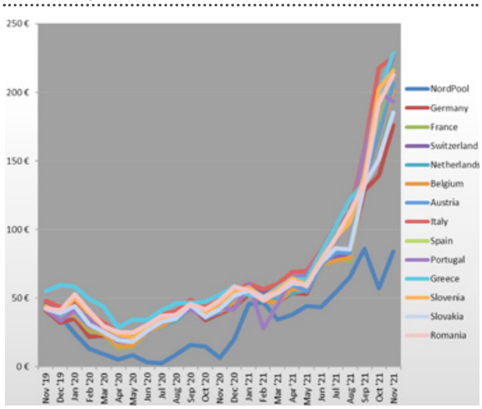
Sources: European Union Agency for the Cooperation of Energy Regulators, Financial Times

In general, gas is the fuel that is needed to make sure enough energy is supplied to meet demand. So even in countries such as France — where cheaper nuclear power provides about 70% of electricity — gas is still driving the wholesale electric price. And as the gas price has soared, so has the price of electricity.

Figure 10.94 **TTF Gas Prices in 2021**

Source: Trading Economics

Figure 10.95 **Variation of European Wholesale Electricity Prices (November 2019 – November 2021)**



Sources: European Energy Exchanges, IENE

Who Benefits from the Current Market Operation?

The EU's energy market has helped to bring down prices across Europe since the late 1990s by accelerating a shift away from long-term contracts for fossil fuels such as oil to less carbon-intensive natural gas and renewables bought on spot markets. Because prices are based on shifting supply and demand dynamics, Europe has even experienced negative prices - most notably during the start of the Covid-19 pandemic in 2020-when supply massively outweighed falling demand. Between 2019 and 2020, Europe's households experienced a 20% fall in the cost of gas, according to figures from Eurostat.

Jan Cornillie, research associate at the European University Institute, said the EU's energy market had "delivered very low prices for years" but a confluence of recent factors - largely outside the control of policymakers - mean that "this is among the first times it is not working in our favour". "The lesson is not to do away with the design altogether but to add insurance mechanisms in times of high prices," said Cornillie.

Brussels is also fiercely protective of a model that it says is crucial to meeting its ambitious climate goals and speeding up the transition to renewable energy. Marginal pricing means all suppliers in the market, including cheaper wind or solar installations, get the price paid for the most expensive offer accepted, providing a boon for capital intensive technologies such as renewable energy. "The market is not dominated by the big players and is open for smaller renewable installations," Simson told the Financial Times.

Is There an Alternative?

Finance ministers from France, Spain, Romania, Greece and the Czech Republic have called for sweeping changes to "better establish a link between the price paid by the consumers, and the average production cost of electricity in national production mixes".

The European Commission has promised to assess how this possible "delinking" could be achieved. But appetite for sweeping changes is low. Changing the marginal pricing rules would also require time-consuming EU legislation.

Many member states, including Germany, the Netherlands and the Nordics, are likely to resist major legal changes in the face of a price surge that experts say is expected to fade by early 2022. "To the extent that [the price surge] is a temporary phenomenon, then the response should be just as transitory," Christian Zinglersen, director of ACER, told the FT.

Would Better Energy Reserves Make Any Difference?

One solution that Brussels is working on is to find ways to boost the EU's capacity to procure and store natural gas so it would be available to smooth out swings in prices at times of high demand. "Volatility is likely here to stay and we need to work on accepting this," said Zinglersen. Only about a dozen member states have their own strategic gas reserves.

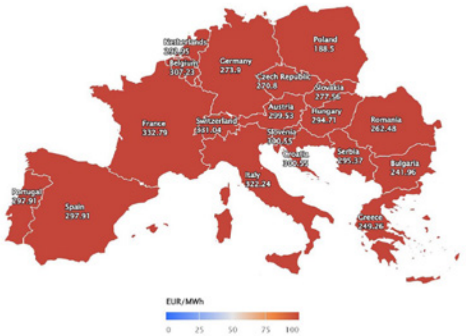
By contrast, the EU already has strict rules on emergency oil stocks: each member state must keep crude oil worth 61 days of consumption and continually report stock levels to Brussels. But moves towards establishing joint EU gas purchasing and storage are likely to be beset by technical difficulties and high costs. Natural gas is stored in underground reservoirs and the market is dominated by commercial players, including Russia's Gazprom.

"Only a few member states may be able to offer storage sites at sufficient scale, again raising the tricky question on how costs are divided between them," noted Christian Egenhofer and Irina Kustova at the Centre for European Policy Studies. Energy commissioner Simson on Wednesday said Brussels would propose a "voluntary" system for joint storage and procurement, encouraging countries who want to participate, but not creating obligatory rules.

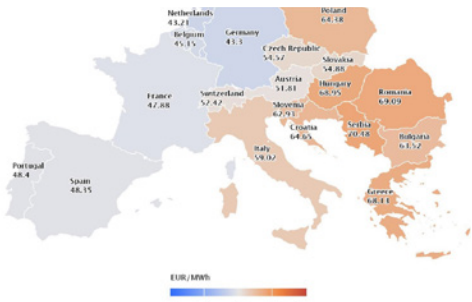
The Case of SE Europe

In SE Europe, heatwaves rocketed demand for power from air conditioning, while below-average wind generation kept demand for gas high in the power sector. The energy crisis, which is also present in SE Europe, have led the majority of the SEE countries to take relief measures in order to shield their consumers from record-high energy prices (see Maps 1 and 2) that have curtailed industrial production and hiked consumer bills.

Map 1 **Wholesale Average Day-Ahead Electricity Prices in Europe, 13-19 December 2021**



Map 2 **Wholesale Average Day-Ahead Electricity Prices in Europe , 14-20 December 2021**



Indicatively, **Greece's** Minister of the Environment and Energy Kostas Skrekas announced that the electricity and heating costs for households would grow only marginally. The funds earmarked for the mitigation of the energy crisis now stand at €1.35 billion until the end of the year, due to the ongoing increase in prices. The Greek government was one of the first in Europe to introduce emergency measures for the protection of households, especially those at risk of energy poverty, from the spike in prices of electricity, gas and heating fuels. Moreover, Greece is setting up a permanent mechanism for future price anomalies in the energy market and working with the European Union on a system that could be implemented in all member states. Minister Skrekas vowed to direct more funds next year for the purpose, if it is necessary[116].

As announced in December, energy supply companies in Greece stand to receive compensation of about €600 million in order to cover subsidized energy support offered by the government to consumers between September and December. An additional amount of €100 million will also be offered to energy suppliers early in 2022 to offset increased energy subsidies for December. All these funds will stem from the Energy Transition Fund.

Albania declared an energy emergency due to the strong rally in electricity prices and said it would allocate €200 million for state-owned power distribution operator OSHEE and introduce other measures to protect households and small businesses. More specifically, Prime Minister Edi Rama recently said that a €100 million fund will be established for OSHEE's liquidity until the end of 2021, which will be boosted by another €100 million in 2022, and offer state guarantees[117].

[116] Todorović, I. (2021a), "Government in Athens doubles subsidies to protect households during energy crisis", Balkan Green Energy News, https://balkangreenenergynews.com/government-in-athens-doubles-subsidies-to-protect-households-during-energy-crisis/

[117] Todorović, I. (2021b), "Albania declares energy emergency as response to energy crisis", Balkan Green Energy News, https://balkangreenenergynews.com/albania-declares-energy-emergency-as-response-to-energy-crisis/

In addition, **Serbia**'s Prime Minister said that the government would not cap the electricity prices as requested by the business sector and state-owned power utility Elektroprivreda Srbije (EPS) announced it cannot offer dumping prices and distort competition.

However, the company revealed it could offer companies more adequate prices if the government adopts such a decision. Earlier, the Serbian Association of Employers demanded the price increase to be gradual. The businesses sector sounded an alarm in early October amid a spike in power prices. The association said electricity suppliers have boosted tariffs by 70% to 135% and warned that companies would be forced to increase the prices of their products and lay off workers[118].

Bulgaria's interim government proposed a payment of €330 million in subsidies to all companies in the country to ease the pressure of high electricity prices. In Bulgaria, power prices have increased 72% from the beginning of the year, and as of September 29 the price on the day-ahead market of the national power exchange IBEX was at €133 per MWh.

Prices for households are regulated and they are currently set to remain at €57 per MWh by the end of the year. In its draft budget for 2022, the government proposed that every company should receive €26 per MWh consumed in the first six months of next year. The government also decided to change the rules for trading electricity at the IBEX exchange to make the market more transparent [119].

Furthermore, **Romania**'s Energy Minister revealed a five-month mechanism that would be rolled out in November to cushion the blow on households and that a similar measure is in the pipeline for small and medium-sized enterprises (SMEs).

More specifically, households that consume between 30 kWh and 200 kWh a month will be entitled to a discount of 3.6 eurocents per kWh, while gas bills should be trimmed by 25%, but on a yearly basis, the Minister said, estimating that the upcoming executive order would help 5.2 million households or 13 million people. SMEs need to be encouraged to conduct energy efficiency measures and install own sources of energy, the minister underscored and vowed to improve existing programs.

He didn't rule out the possibility to extend the subsidies in the spring. On the other hand, President of Romanian Energy Regulatory Authority (ANRE) Dumitru Chiriță suggested electricity bills would be reduced by 10% to 15% if the government decides to pay for the surcharges for the support for renewable energy and highly efficient cogeneration for six months. He told the Parliament of Romania that such a scheme would cost €424 million[120].

Recently, Kosovo and North Macedonia introduced a state of energy emergency due to the jump in prices and their dependence on imports. More specifically, **Kosovo**'s Minister of Economy Artane Rizvanolli said the purchases of power abroad cost €12 million since the beginning of November, calling it an emergency situation. In her words, €12 million was initially earmarked for the whole year. High import bills prompted the Energy Regulatory Office (ERO) to start an unplanned review of electricity tariffs. In addition, there were several outages at the coal plants in Kosovo in the past weeks[121].

Similarly, the government of North Macedonia proposed in early December to the national assembly to prolong the state of energy crisis for six months, until June 9, 2022. The aim of the decision is to ensure stability in the implementation of the measures and activities for overcoming the issues in the electricity supply, the government said.

[118] Spasić, V. (2021a), "Serbia won't cap electricity prices in response to energy crisis – prime minister", Balkan Green Energy News, https://balkangreenenergynews.com/serbia-wont-cap-electricity-prices-in-response-to-energy-crisis-prime-minister/

[119] Spasić, V. (2021b), "Bulgarian government to subsidize electricity price for industrial consumers", Balkan Green Energy News, https://balkangreenenergynews.com/bulgarian-government-to-subsidize-electricity-price-for-industrial-consumers/

[120] Todorović, I. (2021c), "EU to help power consumers as member states launch relief individually", Balkan Green Energy News, https://balkangreenenergynews.com/eu-to-help-power-consumers-as-member-states-launch-relief-individually/

[121] Todorović, I. (2021d), "Rizvanolli: Energy crisis in Kosovo* worsens amid coal plant outage", Balkan Green Energy News, https://balkangreenenergynews.com/rizvanolli-energy-crisis-in-kosovo-worsens-amid-coal-plant-outage/

On November 9, 2021, the government declared a 30-day state of energy crisis due to electricity shortages on the domestic market, caused by occasional outages at major production facilities, the lack of coal for electricity production, and the inability to prevent possible outages with reserves in the electricity production sector [122].

Discussion

The pan-European landscape in the energy sector is currently (Q4 2021) facing a perfect storm, with high gas and electricity prices suffocating companies, households and governments called upon to manage a general wave of price hikes and inflationary pressures that threaten Europe's competitiveness and social cohesion in all European countries, including SE Europe.

The rally in gas and carbon prices, which started in last June and continues until now with a few signs of de-escalation, has pushed wholesale electricity prices to historic highs and the pressure is now being transferred from electricity generation and supply to electricity consumption, causing a shock in households and businesses.

According to the ICE[123], the prices of Dutch TTF Gas Futures will remain high at above €50/MWh at least until March 2022 and the same stands for the overall energy cost. However, it is worth noting that the futures contracts give only an indication and we cannot be sure how prices will fluctuate, as one must take also into account other factors. Several energy analysts support the view that if gas prices fall, then, even if CO_2 prices are high, electricity prices will decrease. This happens at a time that gas contribution in the electricity cost has a much greater impact than CO_2. The main conclusion is that the energy cost is and will remain high until Q1 2022 in the best case scenario.

122 Spasić, V. (2021c), "North Macedonia to extend state of energy crisis for six months", Balkan Green Energy News, https://balkangreenenergynews.com/north-macedonia-to-extend-state-of-energy-crisis-for-six-months/
123 The ICE (2021), "Dutch TTF Gas Futures", https://www.theice.com/products/27996665/Dutch-TTF-Gas-Futures/data?marketId=5285052

References

(1) *Hellenic Republic - Ministry of the Environment and Energy, "National Energy and Climate Plan", Athens, December 2019, Available online at: https://ec.europa.eu/energy/sites/default/files/el_final_necp_main_en.pdf*

(2) *Republic of Bulgaria – Ministry of Energy – Ministry of the Environments, "Integrated Energy and Climate Plan of the Republic of Bulgaria 2021-2030".*

(3) *Clercq, Geert De., "UPDATE 1-Rosatom Wins License to Build Second Nuclear Reactor in Turkey," Reuters, 6 September 2019, www.reuters.com*

(4) *M. Schneider et al., "The World Nuclear Industry Status Report 2019", MacArthur Foundation, NRDC, Heinrich Boll Stiftung France EWS, Stiftung Zukunftserbe, SES, The Greens EFA, Paris, Budapest, September 2019. Available online at: https://www.worldnuclearreport.org/IMG/pdf/wnisr2019-v2-hr.pdf*

(5) *"Framework energy strategy of Bosnia and Herzegovina until 2035", Available online at: http://www.mvteo.gov.ba/data/Home/Dokumenti/Energetika/Framework_Energy_Strategy_of_Bosnia_and_Herzegovina_until_2035_ENG_FINAL....pdf*

(6) *"The 2021-2030 Integrated National Energy and Climate Plan", Romania, April 2020, Available online at: https://ec.europa.eu/energy/sites/default/files/documents/ro_final_necp_main_en.pdf*

(7) *Entso-e, "Continental South East - Regional Investment Plan 2017: Final version after consultation and ACER opinion", October 2019, Available online at: https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP2018/rgip_CSE_Full.pdf*

(8) *Entso-e, "Completing the map – European Power System 2040 – Technical Appendix: Final version after public consultation", October 2019, Available online at: https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP2018/System_Need%20Report.pdf*

(9) *Entso-e, "Project 138 – Black Sea Corridor", Available online at: https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP%202016/projects/P0138.pdf*

(10) *Entso-e, "TYNDP 2018 Project Sheets", Available online at : https://tyndp.entsoe.eu/tyndp2018/projects/projects*

(11) *European Parliament, "Common rules for the internal electricity market", EU Legislation in Progress, a Briefing available online at: https://www.europarl.europa.eu/RegData/etudes/BRIE/2017/595924/EPRS_BRI(2017)595924_EN.pdf*

(12) *EWRC, "Report on the activities of the Commission for Energy and Water Regulation for 2020 (in Bulgarian), Available online at: https://www.dker.bg/uploads/2021/god_doklad_2020.pdf*

(13) *M Stet, (2017), "Characteristics of the Romanian energy market", IOP Conf. Ser.: Mater. Sci. Eng. 200 012067, doi:10.1088/1757-899X/200/1/012067, Available online at: https://iopscience.iop.org/article/10.1088/1757-899X/200/1/012067/pdf*

(14) *P. Lowe et al., (2007), "Effective unbundling of energy transmission networks: lessons from the Energy Sector Inquiry", Directorate-General for Competition, Competition Policy Newsletter Number 1 — Spring 2007, Available online at: https://ec.europa.eu/competition/publications/cpn/2007_1_23.pdf*

(15) *Hungarian Energy and Public Utility Regulatory Authority & MAVIR, "Data of the Hungarian electricity system 2019", Budapest 2020, Available online at: http://www.mekh.hu/download/8/35/e0000/a_magyar_villamosenergia_rendszer_2019_evi_adatai.pdf*

(16) *CGES,"Operating statement of crnogorski elektroprenosni sistem ad for the year 2017", Podgorica, Montenegro, April 2018, Available online at: http://www.cges.me/en/regulation/reports?download=250:operating-statement-for-the-year-2017*

(17) *Energy Law, Official Gazette of the Republic of North Macedonia, No. 96/18., [Online]. Available only in local language: http://www.erc.org.mk/pages.aspx?id=8*

(18) *IEA, "Energy Policy Review: Turkey 2021", March 2021, Available online at: https://www.iea.org/reports/turkey-2021*

(19) *IPTO, "TYNDP 2021-2030", March 2020, Athens, Greece, Available only in Greek online at: https://www.admie.gr/sites/default/files/users/dssas/DPA%202021-2030/dpa2021-2030.pdf*

(20) *C. Nissen et al. "Trends and projections in the EU ETS in 2020 - The EU Emissions Trading System in numbers", EIONET report - ETC/CME 3/2020 - November 2020, Available online at: https://www.eionet.europa.eu/etcs/etc-cme/products/etc-cme-reports/etc-cme-report-3-2020-trends-and-projections-in-the-eu-ets-in-2020/@@download/file/Report_ETS_03_2020_20201218.pdf*

(21) *ERC, Energy and water services regulatory commission of the republic of North Macedonia, "Annual Report 2019", Available online at: https://erc.org.mk/odluki/Annual%20Report%20ERC%202019%20-%20EN.pdf*

(22) *ACER/CEER, "Market Monitoring Report 2019 – Electricity Wholesale Markets Volume", October 2020, Available online at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202019%20-%20Electricity%20Wholesale%20Markets%20Volume.pdf*

(23) *Hungarian Energy and Public Utility Regulatory Authority, "Annual Report, 2018", Avaialble online at: http://www.mekh.hu/download/9/01/c0000/hea_annual_report_2018.pdf*

(24) *ECS, 2021, "Electricity Interconnection Targets in the Energy Community Contracting Parties", Available online at: https://www.energy-community.org/dam/jcr:97afc332-0495-479b-a1d6-848a2c6877a2/ECS_Interconnection_Targets_022021.pdf*

(25) *Thiel C, Nijs W, Simoes S, Schmidt J, van Zyl A, Schmid E. The impact of the EU car* CO_2 *regulation on the energy system and the role of electro-mobility to achieve transport decarbonisation. Energy Policy 2016;96:153–66. https://doi.org/10.1016/j.enpol.2016.05.043.*

(26) *Bloomberg NEF, (2020), "Electric Vehicle Outlook 2020".*

10

11

Renewable Energy Sources

Renewable Energy Sources

11.1 Overview of Renewable Energy Sources (RES) in SE Europe

Sun, wind and rivers have long been used by all countries in South East Europe for heating and cooking, wheat grinding, water pumping and industrial uses but also for power generation. Lately, governments, regions and corporate entities are shifting to renewables and gas as they seek to replace ageing coal fired power generation plants and at the same time reduce carbon-dioxide emissions from a variety of uses in buildings and industries.

However, there are marked differences in execution strategies between the different countries in SEE. While non-hydro renewables have previously been treated with caution, falling costs have prompted South East Europe's policy makers to take a closer look. The region – encompassing EU member states and others in the EU-led Energy Community and Turkey – envisages ambitious targets for 2030 and 2050.

The European Parliament agreed an EU 2030 legislative framework for climate and energy in November 2018 (1). It includes EU-wide targets and policy objectives to lead the global transition to a low-carbon society in a cost-effective manner during 2020-2030, and achieve decarbonisation by 2050. A binding EU target has been set to achieve at least a 32% share for renewables in total energy consumption by 2030.

The European Green Deal, introduced in January 2020 (2), adopted a set of policy initiatives by the European Commission for even higher emissions cuts. As part of the European Green Deal, the European Climate Law (3) has set a binding target of achieving carbon neutrality by 2050. This requires current greenhouse gas emission levels to drop substantially in the next decades. As an intermediate step, the EU has raised its 2030 climate ambition, committing to cutting emissions by at least 55% by 2030. The EU is now working on the revision of its climate, energy and transport-related legislation under the so-called "Fit for 55" package[1] in order to align current laws with the 2030 and 2050 ambitions. The "Fit for 55" package consists of a number of legislative proposals and policy initiatives, including a revision of the renewable energy directive.

In view of the revised targets for emissions reduction by 2030, it is anticipated that the EC, in cooperation with EU member countries, will soon determine new targets for RES share in 2030 total energy consumption.

The EU will also provide financial support and technical assistance to help people, businesses and regions that are most affected by the move towards the green economy under the "Just Transition Mechanism", which will help mobilise at least €150 billion during 2021-2027 in the most affected regions (4).

There is no doubt that achieving the Green Deal objectives requires significant investment. According to the Commission, at least 25% of the EU's long-term budget should be dedicated to climate action. So far, the EU estimates that €260 billion ($290 billion) of additional annual investment will be required to accomplish the 2030 target. A Sustainable Europe Investment Plan was launched on March 15, 2021 and a Green Financing Strategy was adopted by the European Commission on April 21 for the private sector; both are expected to finance the green transition.

The EU Green Deal and SE Europe

Southeast European countries are at a disadvantage in the transition process to a green economy compared to northern Europe, and face systemic challenges to their energy markets. They also face serious challenges, especially the West Balkan Six (WB6) in implementing EU's energy acquis. These issues need to be addressed through a regionally focused approach.

[1] https://www.consilium.europa.eu/en/policies/eu-plan-for-a-green-transition/

There are six main obstacles to more integrated and efficient markets in the region: (i) high dependence on fossil fuels, often supported by policy, (ii) market concentration and state intervention, (iii) illiquid energy markets, (iv) occasionally poor interconnectivity and cross-border energy trade, (v) poor regulatory framework and institutional design, and (vi) lack of strategies for managing the energy transition.

The combination of carbon-intensive energy sectors, relatively low energy efficiency, and below EU average GDP per capita, makes the transformation – of the coal regions, for example – both technically challenging and politically sensitive. The European Green Deal and the 'just transition' facility offer new opportunities for the region (including Covid-19 recovery funds) to develop lower carbon energy systems. But cash injections alone will not be sufficient. Some policy makers argue that the region will require tailor-made mechanisms that reflect its specific needs during the transition (5).

There is widespread feeling that the countries of the region, together with the EU, have the opportunity to make a bold decision about moving forward alongside the bloc towards a sustainable, decarbonised future and reap the region's potential for a healthier environment. The EU also understands that to maximise the impact of the European Green Deal for the whole continent, it should make South East Europe part of this deal and ensure the countries are given equal opportunities and weight. In this way, the EU can guide the region towards implementing the 2030 and 2050 targets while benefiting from the added value the countries of the region could contribute.

Bulgaria, Romania, and Greece are currently responsible for more than nine percent of coal- and lignite-fired electricity generation in the EU, but their approaches are very different. Greece is a good example of a country that has made impressive progress in accelerating its coal phaseout, as evidenced in the 2020 National Energy and Climate Plan (NECP). Some 4.0 GW of lignite plants are to be fully retired by 2023, leaving only one 660 MW lignite plant (currently under construction|), which will operate until 2028 – a fraction of its potential lifespan.

Bulgaria and Romania are helping state-controlled utilities to purchase European Union carbon emissions allowances, but Romania is attempting to move towards decarbonisation.

Romania's Minister of Economy, Energy and the Business Environment Virgil Popescu said on November 2020 that no more coal power plants would be built in Romania, as the country aims to meet 30.7% of its energy needs from renewable sources by 2030, compared to 24.4% at present (6). In the following ten years, Romania intends to increase its installed electricity capacity by 35% with wind power contributing 2,302 MW and solar PV 3,692 MW, thus ensuring a higher degree of energy independence. For the time being Bulgaria does not plan to implement a lignite phase-out despite the fact that financial losses from lignite plants cost taxpayers several hundred million EUR each year in subsidies, meaning that the longer these plants operate, the more they will cost the taxpayer.

As IENE has revealed in a recent study, investments in renewable energy can limit the increase in wholesale electricity prices that could result from a phase-out of lignite, and set countries on an affordable path towards net-zero emissions. In contrast to the (misleading) perception that renewables are expensive alternatives, models (7) show that the level of support required for increasing RES capacities is below 1.5% of the wholesale prices in Bulgaria, below 2.5% in Greece, and below 5.5% in Romania on average, between 2021 and 2030.

The Western Balkans: The proposed policy for Energy Community contracting parties in the Western Balkans is centred around five pillars: decarbonisation, circular economy, pollution reduction, sustainable farming and biodiversity. In order to implement such policies in Albania, Bosnia-Herzegovina, Kosovo, Montenegro, North Macedonia, and Serbia (WB6), co-ordination will be necessary with international financial institutions and civil society organisations. So will the introduction of appropriate legislation. Too often the countries of the region are reluctant regulation followers, despite the ecological and health benefits of EU environmental legislation.

Therefore, the Energy and Transport Community Treaties, as well as the EU accession process could become key implementation tools for most of the countries which are part of the Energy Community Treaty. According to energy community sources, the process must include a legal climate commitment for all Western Balkans countries as well as a robust monitoring mechanism, while sanction tools must be used to achieve full implementation. It is clear that the WB6 Green Agenda should be based on sustainable decarbonisation by 2050, in line with the Paris Climate Agreement and EU climate and energy policies. All countries need to commit to climate and energy targets by 2030, in line with the EU's overall goals. These must be complemented by concrete implementation measures, support and financing, as reflected in the National Energy and Climate Plans (NECPs) and Nationally Determined Contributions (NDCs).

Circular economy: It is widely understood by regional governments that adopting the "circular economy package" is the place to start. In the financial planning of this pillar, budgets should be allocated only for measures which contribute to the circular economy, especially waste prevention, recycling, and composting. Reducing pollution in the region will not be an easy task, considering how long the countries' heavily coal reliant economies have been damaging the air, water and soil, but decarbonisation of the electricity, heat and transport sectors has immense potential in that respect. Circular economy legislation is already in place, so the immediate focus should be on compliance with existing obligations under the Energy Community Treaty.

Inclusiveness: All the above inevitably affects the WB6. But bringing about true transformational change should also mean involving these countries as much as possible in these ambitions. Such mutual interest can offer good grounds for a deal between them and the EU that is fully inclusive. There are at least three reasons to consider such a deal.

First, the energy systems of the Western Balkans are already partly integrated with those of the EU, and further integration is set to expand. Second, the Western Balkans have large unused renewable potential which can be developed to contribute to European CO_2 reduction goals. Third, the region has a well-developed hydro-energy capacity, which is both a good match for renewables and offers the potential for large-volume energy storage.

In short, the Western Balkans have attractive energy assets supporting Europe's energy transition: large coal mining areas with excellent grid infrastructure that can be used for industrial solar; low labour costs; engineering skills; and geographic proximity to advanced industrial economies with high energy demand. With the right incentives, these assets could attract investments in the new wave of low-carbon industries and further contribute to the European industrial transition. The EU could deploy several international cooperation formats to include the Western Balkans in the European Green Deal. Among them are the Energy Community, the European Network of Transmission System Operators for Electricity, the Regional Cooperation Council, Central and South Eastern Europe Energy Connectivity, the Berlin Process, and others. Each of these brings value and tools for achieving this, and for guiding the region towards hosting modern low-carbon, high added-value industries.

International financial institutions like the European Investment Bank (EIB), the European Bank for Reconstruction and Development (EBRD), and the World Bank can play an important part in the energy development of the region as all of these follow strong climate-aligned policies. Recently, the EIB – the largest lending bank in the world – branded itself the "European climate bank", pulled out of investment in fossil fuel projects, and announced that it "will align all financing activities with the goals of the Paris Agreement from the end of 2020" (8).

If the EU wants to maximise the impact of the European Green Deal and make it economically more attractive to all countries, it should incorporate the Western Balkans as a party to it and ensure that the countries there are part of the negotiation process. In this way, the EU will not only help guide the region towards the 2030 and 2050 targets, but it would also be able to extract the maximum value the Western Balkans could offer. This will make the European Green Deal a proper deal, one based on a clear mutual interest in which the region will not fall into the usual role of a policy taker and reluctant regulation follower, but will instead become an active contributor.

This transactional side of integrating the Western Balkans into the European Green Deal would not only accelerate the region's transition, but could also increase the chances of the EU climate-neutral agenda across the continent. The EU should negotiate a deal with the Western Balkans on the basis of the contributions and the assets that the six countries could bring.

Possible Impact of the Covid-19 Pandemic on the Green Deal

Despite the statements of some EU members, namely Poland and Czech Republic, insisting on suspending the Green Deal in order to prioritise the health crisis, on 9 April 2020 the environment ministers of 13 member states publicly announced that "Europe must not forget about the persistent climate and ecological crisis when defining its response to the Covid-19 pandemic," which was subsequently supported by four other member states including France and Germany (9).

The member states called on the Commission to promote sustainable growth and to put the objectives of the Green Deal at the heart of the energy recovery plan in order not to lose track of environmental commitments while addressing the Covid-19 crisis. The statement was welcomed by the Commission since it shows the respect of the member states towards its climate objectives. Recent data show that the biosphere has benefited from the downturn in economic activity including the reduction in greenhouse gas emissions across the world. Dr. Fatih Birol, Executive Director of the International Energy Agency (IEA), thought this a golden opportunity for governments to insert clean energy into their bailout packages (10). EU leaders showed their willingness to use the ongoing crisis to advance climate action by signing a joint statement saying, "the Union remains committed to sustainable growth and the Commission by promoting a public consultation on raising the EU's climate target for 2030," in late March 2020.

Accordingly, on 21 April 2020, the European Council, in cooperation with the EU Commission, put forward a "Roadmap For Recovery" setting forth important principles and investment components to place the green transition at the heart of every national recovery plan across Europe. The transition was seen as achieving the goals of the European Green Deal but also playing a vital role in re-launching and modernizing the economy.

Encouraged by public support through various NGOs and member states, the Commission in September 2020 decided to put forward a comprehensive plan to revise the EU's 2030 emissions reduction target, and suggested amending the recently proposed European Climate Law. However, with the oil prices dropping to their lowest level in recent history in 2020, several Eastern European countries heavily dependent on fossil fuels are expected to stick to their pre-green deal policies and prioritise fossil fuels. It is therefore too early to tell whether Covid-19 will promote or disrupt the Green Deal.

The COVID-19 crisis impacts on the renewable energy supply chain

The Covid-19 crisis has amply demonstrated how important access to reliable electricity is in protecting health and wellbeing, in supporting essential public services and key supply chains, livelihoods and national economies. The pandemic has put forward a case for accelerating equal energy access. Lack of reliable electricity – a daily reality for hundreds of millions of people living in Sub-Saharan

Africa, South Asia, Latin America and parts of Europe – severely compromises people's ability to live healthy, happy lives. During 2020-2021 there has been a heightened focus on renewable technologies and the role they can play in increasing energy access. There have been calls for renewable energy to be at the forefront of countries' response to COVID-19, with many seeing an opportunity to 'build back better' using low-carbon technologies to create more resilient and sustainable energy systems, while boosting economic growth and creating employment.

However, the spread of COVID-19 has caused mass production shutdowns and serious disruptions along the supply chain across several industry sectors, particularly in China where the virus originated. Wider disruptions are now being experienced as other countries take steps to contain or delay the spread of the virus. The impact on the power and renewables sector is likely to be considerable, as efforts to control the virus are likely to persist until 2023. For projects under construction, delays in the delivery of key components – which are either in transit or simply not being produced as manufacturing plants are closed – will hamper schedules and could increase costs as parties look to source parts elsewhere. Renewables projects are particularly vulnerable with China being a significant producer of solar photovoltaic panels and wind turbines. Contractors reliant on an international workforce will also be impacted as travel restrictions or quarantine measures are imposed.

For projects which are commissioned, generators may be forced to shut down or reduce capacity where their workforce is subject to quarantine measures and cannot reach work. Such projects may also face reduction in demand as the energy requirements of major users (e.g. manufacturing plants) fall, leading to business plan upsets. Projects in the procurement phase are particularly vulnerable to the impact of Covid-19. These are likely to affect prices due to supply shortages, impacting profitability. The ability of parties to participate in tender processes may be impaired, particularly if contractors cannot get to the site in order to assess the risks properly so as to bid competitively. We have also seen projects being placed under pressure to use more expensive supplies from markets such as the US or Europe in order to overcome the shortfalls caused by Chinese suppliers - a situation which appeared to have been resolved in Q1 of 2021. However, as the pandemic gains a foothold in global markets, this argument will become less relevant. Where agreements are as yet unsigned, parties may seek to provide a special regime to deal with Covid-19 within their agreement. For projects with debt finance, lenders are likely to be wary of committing further funds unless the implications related to Covid-19 can be properly assessed and mitigated.

With further disruptions expected, the knock-on effect will be delays in the progress of construction work and parties risking missing key milestones. This may result in project developers facing penalties or, in some cases, losing tax incentives, tariffs or other revenue sources. In the US, for example, renewable energy developers may lose important tax credits as a result of delays in construction. Parties may seek to pass liability for economic losses down to contractors. Whether claims will be successful will depend on the provisions of the agreement, including any regime for delay of liquidated damages and any applicable exclusion clauses. Project developers will also need to consider the implications of delays under their funding arrangements, particularly whether these constitute a default or trigger a restriction on utilisations.

The impact of the coronavirus is a major concern for the global wind industry describing it as "a crisis unlike anything the market has ever seen," according to global energy consultancy Wood Mackenzie (11). For solar energy, the global coronavirus outbreak has resulted in shutdowns in Spain, Italy, Malaysia and parts of the US, which will affect solar inverters and module production. In the US, ports remained open and site construction continued but impacts from smaller bill-of-materials equipment and project permitting delays have hampered production.

Battery production is seeing a trend change with a ramp up in both China and South Korea, while automotive manufacturing facilities in Europe and North America are closing down or shifting to medical equipment production. The impact on electric vehicle sales is too early to gauge, although sales remained strong through 2020 while near-term project execution and demand for grid applications was driven by local demand. The impact on technology supply chains and installations is now coming into view (2H 2020), while existing energy producers and electric vehicle and energy equipment manufacturers navigate crashing demand and margins. According to market analysts, the primary risk to regional power markets is a prolonged recession.

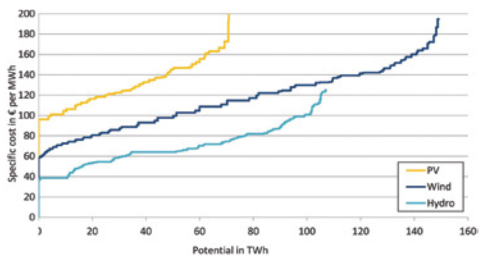
The role of RES in the energy transition process

Many analysts believe that the current decade could prove pivotal for the energy sector in SEE. The region possesses considerable renewable energy potential. To harness it, the region will need to set new targets, ensure sustained investment in variable renewable energy technologies, develop its modern biomass industry and introduce a holistic policy framework.

With the creation of new jobs in the renewable energy sector, an energy transition would also help tackle long-standing unemployment and brain drain issues. The inclusion of improvements in health and air quality, ensures that potential gains further outweigh additional costs. Ultimetly, the energy transition will entail the complete phaseout of the aged fossil fuel plants and the parallel introduction of largescale RES applications in the power sector. It should be noted though, that most of the renewable energy capacity is concentrated in the EU member states of SEE, while the rest of the region has been relatively slow in implementing RES projects. The countries in the bloc benefited from the early adoption of medium-term, technology-specific targets for renewable energy and the introduction of dedicated supporting policies.

Between 2001 and 2018, a large segment of SEE countries (Albania, B-H, Bulgaria, Croatia, Kosovo, Montenegro, N. Macedonia, Romania, Serbia and Slovenia) received US$20.7 billion in renewable energy investment excluding large-scale hydro. The timeline starts from zero in 2001 and reaches a peak of USD 3.7 billion (Euros 3.035 billion) in 2012 (12). In 2018, alone total expenditures were US$1.49bn (Euros 1.22 billion). Yet overall, renewable energy investment remains fragile in SEE. Fluctuations can largely be attributed to the presence (or lack) of dedicated supporting policies. Without a stable policy and an adequate regulatory framework, regional investment in renewable energy will continue to be unstable.

Figure 11.1 **Long-term cost and potentials of renewable technologies (EUR/MWh) in the SEE region**



Source: South East Europe electricity roadmap – modelling energy transition in the electricity sectors

The adoption of the second EU Renewable Energy Directive (RED II) gives governments in SEE the opportunity to update renewable energy targets. These updated targets could be designed to make better use of the improved visibility of the energy sector, promote adaptation measures and realign targets to reinvigorate renewable energy deployment. According to an IRENA report (Renewable Energy Market Analysis, 2019) five countries from the region – Albania, North Macedonia, Serbia, Slovenia, and Kosovo – have not yet reached their 2020 renewable energy targets. Bulgaria, Croatia, Montenegro and Romania reached their national targets in 2015 for the share of renewable energy in gross final energy consumption by 2020. In 2018 Greece joined the group, achieving its target of 18% renewables in energy consumption. Renewables' share in the European Union was also 18% in 2018, half of a percentage point more than in 2017, compared to the 2020 target of 20%. Among the five countries that have not reached their national targets, Serbia has the longest road ahead. Its compliance is 20.3%, compared to a target of 27%. Ihe country's renewable energy share in consumption has actually been decreasing since 2015.

In Kosovo 24.9% of energy consumption comes from renewables, against a 25% target. Albania needs 3.1 points to hit its 38% target, and North Macedonia is 4.9 points short of its 23% goal. At 21.1%, Slovenia is lagging behind its 25% target. The share of renewable energy consumption in Turkey reached 13.7%, but the country doesn't have a 2020 target. Montenegro is again the regional leader with 38.8%, though its share of renewables in consumption is now on a downward trend. In 2014, the level was 44.1%. Table 11.1 shows the share of energy from RES as compared to the 2020 set targets, while Table 11.2 summarizes the installed electricity capacity from RES for 14 core countries of the region.

Table 11.1 **Share of energy from renewable sources (as % of gross final energy consumption)**

	2004	2015	2016	2017	2018	2020 target
EU	8.5	16.7	17.0	17.5	**18.0**	20
Belgium	1.9	8.0	8.7	9.1	**9.4**	13
Bulgaria	9.2	18.3	18.8	18.7	**20.5**	16
Czechia	6.8	15.1	14.9	14.8	**15.1**	13
Denmark	14.8	30.9	32.0	35.0	**36.1**	30
Germany	6.2	14.9	14.9	15.5	**16.5**	18
Estonia	18.4	28.2	28.7	29.1	**30.0**	25
Ireland	2.4	9.1	9.3	10.6	**11.1**	16
Greece	7.2	15.7	15.4	17.0	**18.0***	18
Spain	8.3	16.2	17.4	17.6	**17.4**	20
France	9.5	15.0	15.7	16.0	**16.6**	23
Croatia	23.4	29.0	28.3	27.3	**28.0**	20
Italy	6.3	17.5	17.4	18.3	**17.8**	17
Cyprus	3.1	9.9	9.9	10.5	**13.9**	13
Latvia	32.8	37.5	37.1	39.0	**40.3**	40
Lithuania	17.2	25.8	25.6	26.0	**24.4**	23
Luxembourg	0.9	5.0	5.4	6.3	**9.1**	11
Hungary	4.4	14.5	14.3	13.5	**12.5**	13
Malta	0.1	5.1	6.2	7.3	**8.0**	10
Netherlands	2.0	5.7	5.8	6.5	**7.4**	14
Austria	22.6	33.5	33.4	33.1	**33.4**	34
Poland	6.9	11.7	11.3	11.0	**11.3**	15
Portugal	19.2	30.5	30.9	30.6	**30.3**	31
Romania	16.8	24.8	25.0	24.5	**23.9**	24
Slovenia	16.1	21.9	21.3	21.1	**21.1**	25
Slovakia	6.4	12.9	12.0	11.5	**11.9**	14
Finland	29.3	39.3	39.0	40.9	**41.2**	38
Sweden	38.7	53.0	53.4	54.2	**54.6**	49
United Kingdom	0.9	8.3	9.0	9.7	**11.0**	15
Norway	58.5	69.1	70.2	71.6	**72.8**	67.5
Montenegro	:	43.1	41.6	39.7	**38.8**	33
North Macedonia	15.7	19.5	18.0	19.6	**18.1**	23
Albania	29.6	34.4	35.5	34.5	**34.9**	38
Serbia	12.7	22.0	21.1	20.3	**20.3**	27
Turkey	16.2	13.6	13.7	12.8	**13.7**	-
Kosovo**	20.5	18.5	24.5	23.1	**24.9**	25

*Data estimated Source: Eurostat

Table 11.2 **Installed RES electricity capacity in the 14 SEE core countries**

Renewable Energy Installed Capacity (MW) in SE Europe (2020)							
Country	Total Installed Electricity Capacity	Hydro	Wind	PV	Biomass / Biogas	Geothermal	TOTAL RES Installed Capacity
Albania	2.212	2.110	0	3	0	0	**2.113**
Bosnia & Herzegovina	4.757	2.000	135	20	3	0	**2.158**
Bulgaria	12.165	3.200	700	1065	100	0	**5.065**
Croatia	5.122	2.200	738	70	77	16	**3.101**
Cyprus	1800	0	158	129	10	0	**297**
Greece	20.700	3.400	4.000	3.000	83	0	**10.483**
Kosovo	1.597	80	33	7	0	0	**120**
Montenegro	1.045	700	118	2	0	0	**820**
North Macedonia	4.408	692	37	26	11	0	**766**
Romania	23.028	6.600	3.040	1.380	133	0	**11.153**
Serbia	8.485	3.000	481	21	15	0	**3.517**
Total without Turkey	**85.319**	**23.982**	**9.440**	**5.723**	**432**	**16**	**39.616**
Turkey	93.000	29.200	8.056	6.700	877	1.550	**46.406**
Grand Total	**178.319**	**53.182**	**17.496**	**12.423**	**1.309**	**1.666**	**85.999**

Country Roundups

West Balkans

The six Western Balkan countries – Albania, Bosnia-Herzegovina, Kosovo, Montenegro, North Macedonia and Serbia – need to invest considerably in moving from coal-fired to renewable energy production, and have a good potential to achieve that.

The 6 West Balkan countries (or WB6 - Albania, Bosnia-Herzegovina, Kosovo, Montenegro, North Macedonia and Serbia) have a long-term renewable energy potential which according to the *Investing in Clean Energy in the Western Balkans Report* will need some €15bn in hydro investments or up to €20bn in wind investments to achieve[2] their goal by 2030. Currently, the six countries lag significantly behind the rest of Europe in the modernisation of their energy sectors, which are characterised by limited market mechanisms and limited private sector participation, insufficient and ageing infrastructure, high reliance on fossil fuels, late adoption of renewables beyond hydropower

[2] Fourth Edition of the "Investing in Clean Energy in the Western Balkans" report released by the Western Balkans Investment Framework (WBIF), January 2020

and residential biomass, limited RES energy production, and high rates of energy poverty despite usually high levels of direct and hidden energy subsidies. The picture varies across the region. Three states, Montenegro, North Macedonia and Serbia, have improved their energy productivity at a considerably higher level than the EU average over the last decade, while energy productivity has actually gone backwards in Bosnia-Herzegovina.

Eight of Europe's ten most polluting coal-fired plants are located in the West Balkan region and all 16 coal-fired plants in the region perform poorly compared to the 250 such plants in the EU, being responsible for at least €1.2bn worth of health damages every year in the region alone. Skopje, Tetovo and Tuzla usually rank among the worst cities in Europe for air quality.
Decarbonising the regional energy sector is the most important step that would reduce emissions and improve the air quality. The International Renewable Energy Agency (IRENA) has estimated that capacities of 12.2 GW for wind and 4.4 GW for solar power could be cost competitive in the region. The Western Balkans' current total power generation capacity is 18.6 GW, half of it coming from coal. However, unlike most EU countries, the Western Balkans have not committed to phase out coal yet but instead plan to add significant new coal power capacity by 2030, in contradiction with commitments under the Energy Community Treaty.

Although the current power generation situation appears favorable, with hydropower accounting for approximately half of current capacity in the region, the rest of that capacity, almost exclusively coal-fired plants, delivers the bulk of the electricity produced due to its high capacity factor. The only exception is Albania, which is completely dependent on hydropower plants. In addition, the environmental credentials of several small hydro plants and projects are often challenged by residents and NGOs.

The main non-hydro emerging RES are primarily wind farms. Serbia and Montenegro built their first wind farms in 2017. In Bosnia, the first wind farm started operation in 2018 and two others are under construction. North Macedonia has only one wind power plant, at Bogdanci. The solar projects in the region are still at an early stage with construction scheduled to start in Montenegro in 2022 and involves a 250 MW installation. On September 2021 The Government of North Macedonia has given the green light to develop a 415 MW wind farm and to the Energy Financing Team (EFT) to build an 80 MW solar photovoltaic facility, granting them the status of a strategic investment project under a law passed in 2020.

Albania

Albania has potential for solar energy generation, as well as for wind and geothermal energy. It has already launched its first solar power projects as it aims to diversify electricity generation away from hydropower, which currently accounts for 95% of capacity. According to a recent IRENA study, Albania's technical potential for the deployment of solar PV is estimated at 2,378 MW, with production of 3,706 GWh annually. According to the report, insolation is very high across most of Albania at over 1,500 kWh/square metre a year, and the country has one of Europe's highest numbers of sunshine hours per year. This gives the country "significant potential" for development of solar PV for power generation and solar thermal for heating purposes.

According to estimates, Albania also has a cost-competitive wind capacity of up to 7,400 MW. Annual average wind speeds range from 3.3 to 9.6 metres per second. Although the country does not yet have any wind power plants in operation, since the introduction of the wind feed-in tariff (FiT) support scheme, 70 applications for the construction of wind farms of up to 3 MW have been filed, and three have been authorised for construction. As elsewhere in Southeast Europe, Albania has low-enthalpy geothermal energy resources, most likely applicable for heating rather than power generation.

These are mainly to be found in the Kruja geothermal area that extends from the Adriatic Sea in the north across the country towards the Greek border in the south. Biomass use is mainly through burning firewood for heating.

Although the country has a plant with capacity to produce 100 kilotonnes of biofuels a year, it operates at only 10-15% of capacity on average. Biogas and biomass power production could reach 86 MW (495 GWh annually) by 2030.

Bosnia-Herzegovina

Just 1.5 percent of Bosnia-Herzegovina's total installed electricity capacity comes from renewable sources. The technical potential of renewable energy is huge, particularly for solar photovoltaic energy. Both of the country's two political entities, the Republic Srpska (RS) and the Federation of Bosnia and Herzegovina (FBiH), promote electricity generated from renewable sources via a feed-in tariff. In both RS and FBiH, the guaranteed tariffs are calculated by adding technology-specific premiums to a reference price. In FBiH, technology-specific conversion factors are multiplied by the reference price of 0.081 BAM/kW-h. In RS, absolute determined premiums are added to the reference price of0.0541 BAM/kW-h in RS. In addition, RS offers a premium for electricity produced from renewable sources, which is either sold directly to the market or is used for its own consumption. Tariffs are granted for 15 years in RS, and for 12 years in FBiH.

In September 2020, upon the proposal of the independent system operator (NOS BiH), the State Electricity Regulatory Commission of Bosnia and Herzegovina (SERC) increased the permitted capacity of wind power plants which may be connected to the transmission network (from 460 MW to 840 MW) and solar power plants (from 400 MW to 825 MW). Priority or guaranteed access to the grid for renewable energy producers remains unsecured. In June 2020, the Parliament of the Federation of Bosnia and Herzegovina adopted a Declaration on the Protection of Rivers calling for a prohibition of small hydro power plants.

Bosnia-Herzegovina should transition towards a market-based renewables support scheme. It should also transpose provisions on the sustainability of biofuels and establish an electronic system for guarantees of origin as a matter of priority. Since 2017, Bosnia and Herzegovina reported a significant increase in the share of renewable energy in comparison to previous years and reached its sectorial target for the share of renewable energy for heating and cooling. Nevertheless, additional efforts are needed to increase the use of renewable energy in the electricity sector as well as in transport in order to reach the overall target of 40% of renewable energy in gross final energy consumption by 2020.

After Mesihovina (51 MW, in operation since 2018), a second wind farm (Jelovača, 36 MW) was commissioned in 2019 and in 2021 the 48 MW Podvelezje wind farm, a project worth 77 million euro ($93 million), was completed. In addition, 20 MW of solar PV, and 26 MW of biogas and biomass have been installed in the reporting period.

Montenegro

In the last three years (2018–2020), Montenegro produced more than 60% of its electricity from renewable energy sources, which is the result of a good investment environment and an inherited production infrastructure. The main sources of renewable power generation are the Piva and Perućica hydropower plants (HPPs). Wind energy accounts for about 10% of power generation and 13 small hydropower plants (SHPPs) contribute to diversification.

In 2017 the 72 MW EBRD-financed Krnovo wind farm came online – the first in the country – and now contributes 22% - 28% of Montenegro's electricity generation. It was followed in 2019 by the 46 MW Možura wind farm. Montenegro has so far made little use of its solar potential, but in 2018 a tender for a 200 MW solar farm was completed. As in other Balkan countries, the construction of small hydropower plants has caused widespread public outcry in recent years, but in 2018 they generated just 2.8% of Montenegro's electricity.

Montenegro's strategy is to keep maintaining the good investment environment in RES in order to obtain as much energy as possible using clean technologies, but also to adopt other technologies, which will enable cleaner use of fossil fuels. Preparations are under way for the Pljevlja thermal power plant's

(TPP) environmental reconstruction, aimed at achieving all EU and Energy Community requirements concerning gas and particulate emissions. In 2019, a contract was signed for the construction of the Briska Gora solar power plant, while the government received two proposals– from Montenegro's EPCG, for the second phase of the Krnovo wind farm, and from Germany's WPD, for the construction of a wind farm at the Brajići locality.

Kosovo

According to the EBRD, Kosovo has just 109.4 MW of renewable energy capacity installed to date, consisting of 80 MW of small hydro, a 32.4 MW wind farm in the east of the country and 7 MW solar PV plant. A 105 MW wind farm is being developed in North Kosovo, with commercial operation scheduled for 2022. Kosovo recently raised its renewable energy target to an additional 400 MW capacity by 2026. That would be enough to meet a quarter of its power demand and reduce dependence on ageing coal power plants. The previous plan for renewables development, put in place in 2016, stipulated the addition of just 10 MW of solar while targeting around 250 MW of overall clean energy capacity. Hence, there appears to be a significant swing in favor of RES and developing a favorable investment environment.

North Macedonia

In late 2018, the Ministerial Council of the Energy Community (EnC) adopted a decision to lower North Macedonia's 2020 target for the share of renewable energy in its final energy consumption from 28% to 23%, at the request of the country's authorities (13). The North Macedonian market is currently one of the hot spots for investments in renewables in the CEE region. Institutional investors and financiers have shown interest in developing new projects, and the government has announced tender awards for large-scale projects. Given that several renewable projects began over the past few years, the market is now expected to experience significant growth. In terms of regulation, the country has now harmonised its principal legislation with the EU acquis, but the necessary by-laws allowing for full implementation are in the process of adoption. Among the main innovations brought about by the recent legislative changes are price premiums, which may now be used as an alternative to more traditional feed-in-tariff schemes.

In 2016, North Macedonia had achieved only an 18.2% share of renewable energy in its gross final energy consumption, instead of its 24.6% median trajectory goal for 2015-2016. In 2020, the country had a total of 766 MW in renewable capacity, including large hydropower plants with a combined installed capacity of 585 MW, small hydropower plants of 107 MW, wind energy with a 37 MW installation (Bogdanci wind farm), a solar energy capacity of 26 MW and a biogas-biomass capacity of 11,3 MW.

Currently, the main goal of reforms in North Macedonia's energy sector is to ensure increased investment in renewable energy projects and to attain national targets for the share of RES in gross final consumption. However, caps imposed on several sources like wind, solar, biomass and biogas prevent the country from reaching its targets. In addition, as the "premiums" were only recently introduced in the North Macedonian energy market, they are not yet applied in practice. It is only through the functioning of the market that we shall find out how effective and competitive this mechanism is.

Serbia

Total electricity production under Serbia's subsidy scheme for privileged power producers, mainly from renewables, doubled from 638 GWh in 2018 to 1,361 GWh in 2019 with a total installed capacity in 2020 at around 3.500 MW. According to a 2018 Report produced by the state-owned Electric Power Industry of Serbia (EPS), privileged and temporary privileged producers generated most of the electricity in hydropower plants, wind farms and natural gas power plants.

In 2019, the energy mix changed when three wind farms were commissioned: Čibuk 1–158 MW, Kovačica–104.5 MW, and Košava – 69 MW, thus taking over the lead with 892 GWh out of total 1,361 GWh of electricity produced from renewables. The growth of output by privileged power producers is the main barometer for the development of renewables in Serbia. Total electricity generation in 2019 was 36,000 GWh, while Serbia's share of renewable energy sources in final energy consumption in 2020 was 20%.

It could be said that the rise in RES produced electricity came as a result of the decree on incentives for the production of electricity from renewable energy sources and high-efficiency heat and power co-generation, under which all privileged power producers have been receiving feed-in tariffs. However, on December 31, 2019, the decree expired. Since then the government has not introduced a new supporting mechanism for renewables, nor has it provided any official information on when exactly this is to take place.

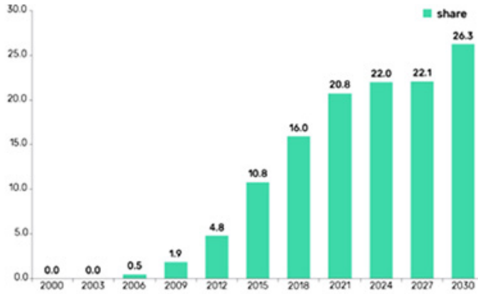
In 2018, authorities announced changes to renewables' incentive model and in 2020 claimed that auctions for wind farms and solar power plants would be rolled out. Further to this, and as a result of the state of emergency declared on account of coronavirus, the government of Serbia has decided to suspend the effect of the power purchase agreements between EPS and privileged producers until further notice. This decision has inevitably impacted negatively the prospects for further expansion of Serbia's RES market.

EU Member States

Croatia

Croatia increased the share of renewable energy in its gross final energy consumption in 2018, joining the group of European Union member states that have surpassed their national 2020 binding targets, according to Eurostat (January 2020). In 2019, the share of energy from renewable sources in gross final energy consumption in Croatia reached 20.0% with total installed capacity from RES at 3,1 GW. Croatia aims to increase its wind energy capacities by a factor of three and solar energy capacities by a factor of 20 in the next 10 years. With wind and other renewable energy sources, Croatia will be able to achieve a 32% share of renewables in its gross energy by 2030 and at least 56% by 2050. In 2019, a total of 12,120 GWh of electricity was produced in Croatia, of which 1,433 GWh (11.8%) corresponded to wind energy.

Figure 11.2 **Croatia, Share of RES in overall cumulative capacity (%), 2000-2030**



Source: GlobalData Power Intelligence Center

An increasing share of renewable power in the electricity mix will drive the country to attain security of supply by reducing its share of electricity imports from the current 62.5% of the country's consumption to 44% by 2030. Over the last few years renewable energy and distributed energy resources have changed the market dynamics of the electricity system. The falling cost of renewable energy installations and the introduction of strong policies to cut down emissions have led policy makers to focus more on this. Croatian state utility HEP is also planning to boost its renewable power capacity by 50%. Besides renewables, the government is encouraging investments in combined heat and power (CHP) plants in order to increase fuel efficiency, reduce pollution, energy and variable cost and wastage.

Bulgaria

Bulgaria is on track to be one of the most affected countries by the EU's decarbonisation policies. The country accounts for 7% of the coal used in the EU and 8% of the jobs in the EU's coal sector. The transition from coal to alternative fuels alone is estimated to cost more than €20 billion over the next ten years. According to Eurostat, Bulgaria is among the 12 EU members that attained their renewable energy targets, ranking 12th in the EU in terms of its share of energy derived from renewables.

It has a total installed capacity of 5.065 MW from renewables, which represents the 20.5% of gross final energy consumption in this country, above the EU average of 18%, well above the level of 18.7% reached in 2017, and far above the set target share of 16% for 2020. Bulgaria vowed to increase the share of wind, solar and other types of renewable energy sources respectively to 27% of its energy consumption by 2030.

According to the Electricity System Operator's (ESO) plan for the development of the country's power distribution network, Bulgaria aims to add over 2,500 MW of installed renewable power capacity by the end of 2024, mostly from solar plants. More specifically according to ESO, 700 MW of wind farms, 1,600 MW of solar parks and 219 MW of biomass-fired power plants between 2020 and 2024 are planned. Bulgaria is targeting a further 2,645 MW of installed electricity generation capacity from renewable sources, mostly photovoltaic plants, by the end of 2030, in line with the EU's goals for green energy transition, according to a national strategy blueprint published in 2019. An analysis by the International Renewable Energy Agency (IRENA) about the RES potential in EU countries suggests Bulgaria can do even better. According to this analysis, by 2030 Bulgaria can achieve a 35% share of renewable energy in total energy consumption and that the energy produced by wind farms will have a significant share in the renewable energy production. (14).

Bulgaria will support the long-term objective of achieving carbon neutrality in the EU by 2050 but the country has reservations about the proposal to include certain transport modes and buildings in the Emissions Trading Scheme (ETS), labelling the idea as "extremely unfavourable". A Mobility Package is also included in Bulgaria's "green" arguments. Sofia insists on dropping the legislative proposal which requires empty trucks to return every month to the country of registration. In recent years, the electricity market in Bulgaria has been undergoing changes, including the introduction of new rules for renewable energy producers, the abolition of the electricity export levy, and market coupling projects with neighbouring countries. In April 2019, Bulgaria adopted a set of amendments to the Energy Act, which entered into force on 1 July 2019. One of the requirements was that all renewable energy producers with a capacity from 1 MW to 4 MW sell their electricity in the free market, freeing about 750 MW capacity to the market. Arguably, this is a step towards market opening. Prior to this, electricity was bought by NEK and sold in the regulated market. Barriers for investments in new renewable projects still date from past retroactive measures. The 5% turnover tax for energy producers, which was introduced in 2013 to balance the energy system financially, remains in place. Similarly, a 5% levy also applies for all new energy investment projects. Removal of these taxes, ideally for new and existing projects, will stimulate new commercial renewables projects for in-country consumption, financed without any subsidies.

The transition to a carbon free economy and the decarbonisation process will not be easy for Bulgaria. Around 8,800 people are directly involved in coal mining in Bulgaria, while those indirectly affected are estimated at over 94,000, with social costs at approximately €600 million per year. The amount of €33 billion needed for the Green Deal corresponds to half of Bulgaria's GDP. If the investment pace is steady, in order to complete the Green Deal, the government will have to spend some 5% of the country's GDP each year.

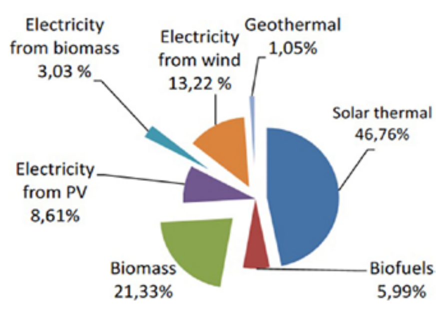
Sofia insists that pushing for the completion of the Green Deal at any cost with insufficient financial compensation will jeopardise energy security and its geopolitical position, and would pose serious competitive challenges even at local level (15). As Bulgaria is located at the EU's external borders, issues related to competition from the outside seem serious. The cement industry is already moving production to North Macedonia and Turkey, while ammonia production is experiencing serious difficulties due to its low cost in non-EU countries. Most energy-intensive industries in Bulgaria are already using natural gas while cement plants use biomass and waste, meaning that their emission reduction capabilities are technologically limited. In its position paper to the EC in February 2020, Bulgaria explicitly emphasises that it will continue to use nuclear energy and is considering the construction of new facilities.

The water sector also presents a major drain on resources. More than €3 billion are needed to meet the minimum requirements of the European Urban Waste Water Treatment Directive. Improving air quality will cost at least €1.7 billion, while the government acknowledges that the sum could be much bigger. The necessary investments needed for waste management by 2027 are estimated at €500 million. Approximately €2.35 billion is also needed for social adaptation. Increasing the energy efficiency of old buildings which will cost an extra €2.5 billion by 2030.

Cyprus

The share of primary energy met by renewables has increased steadily in Cyprus over the last decade to around 6.07% of total primary energy consumption in 2016. The bulk of renewable energy, about 68%, comes from solar thermal and biomass. Wind is the next-biggest contributor, providing 13% of total renewable energy. Biofuels has seen the biggest increase -from zero 0 in 1990 to contributing around 6% of total renewable energy in 2018.

Figure 11.3 **Existing Renewable Energy Share between technologies as of the end of 2018**



Source: Cyprus' NECP 2021-2030

Although Cyprus is unlikely to hit its 2022 renewable energy targets, the island has made significant progress in harnessing renewable energy sources, particularly in terms of solar power. Cyprus has the highest solar potential of any European Union country, but currently imports most of its energy requirements. The Cyprus Renewable Energy Roadmap agrees with a 2015 assessment by IRENA, that the island could generate between 25 and 40 percent of its needed electricity supply by 2030 from RES (16).

Table 11.3 **Cyprus Electricity Generation per technology until 2018**

Cyprus: Electricity Generation per Technology until 2018

Electricity production from renewable sources (GWh per year)	Solar	Wind	Biogas	Total
2008	2.55	0	11.54	14.09
2009	3.83	0	26.52	30.35
2010	6.39	31.37	35.12	72.88
2011	11.94	114.31	51.61	177.86
2012	21.54	185.48	50.02	257.04
2013	47.11	231.04	48.86	327.01
2014	83.59	182.85	50.55	316.99
2015	126.66	221.86	51.24	399.76
2016	147.65	226.7	52.02	426.37
2017	173.73	211.45	51.91	421.68
2018	195.29	220.61	36.10	452.01

Source: Cyprus' NECP 2021-2030

Solar PV is the predominant renewable energy technology in all scenarios, supplying between 15% and 27% of the electricity consumed in Cyprus in 2030. Wind is the second most important RES. The scenarios at the low end of the renewable energy share are limited in terms of penetration of variable RES, based on the constraints outlined by the Ministry of Energy, Commerce, Industry and Tourism. The ministry's constraints are based on provisional results from a study on grid stability commissioned by CERA (Cyprus Energy Regulator), which will be revised by a subsequent study under development by the Joint Research Centre (JRC) of the European Commission.

With the country's electricity network heavily dependent on oil and diesel generators, the government has moved into action, by promoting alternatives such as offshore natural gas, but also providing funding to focus on renewable energy sources for the general public. The 2019 budget for this sector was €64.96 million, with €58.61 million committed to subsidies, of which €29.81 million were directly related to generating electricity from renewables. The €29.81 million included €25 million for a new subsidies plan design, to encourage the use of renewable energy sources for houses (net metering and roof insulation), and promoting 'green' transport – such as plug-in electric or hybrid vehicles.

The new scheme for roof insulation grew from €3.5 million allocated in 2018, to €6.5 million in 2019. The scheme subsidises a household's expenses for roof insulation up to 30 percent, with a maximum of €1,500 per house. For rooftop photovoltaic installations, the maximum contribution per household will be €4,500, up from €3,600 last year. There continues to be much ground to cover in terms of renewable energy production, but international interest in developing the sector in Cyprus has been on the rise. In this respect, the production of renewable energy is expected to experience considerable growth in coming years, and significant investment is required in order for Cyprus to achieve its targets –opening the field for companies with expertise in renewables.

Greece

Greece is fast becoming one of the lead countries in Europe in the adoption of renewables. In 2019 the country was ranked 9th in the world, with about 29% of its electricity production deriving from renewable energy sources (RES), including hydroelectric, wind, photovoltaic (PV), and bioenergy, with total renewable installed capacity of more than 10.000 MW (2020). By 2030 the RES contribution to the electricity mix is expected to exceed 60%, exceeding EU targets.

Greece's first National Energy and Climate Plan (NECP) was presented in December 2019 following public consultation and a debate in the Greek Parliament. In January 2020, Greece submitted a fully revised NECP with higher targets for RES and Energy Efficiency. The NECP is an ambitious plan in accordance with the UN Agenda 2030 and its 17 global Sustainable Development Goals as well as with the adopted European Green Deal, setting, in some cases, even higher targets at national level. The NECP comprises among others, the following axes:

- Decarbonisation and the ending of Greece's reliance on lignite, is scheduled to be achieved by 2028, and is considered a top priority. A detailed schedule for the withdrawal of lignite-fired power stations operated by Public Power Corporation (PPC) was presented in 2020 with almost 4.0 GW of lignite-fired plants to be retired by 2023.
- The NECP now requires renewables to supply 35% of Greece's final gross energy consumption by 2030, up from 31% in the previous (2019) plan. Of this, renewable energy systems are set to account for a staggering 61% of Greece's electricity consumption by 2030. Renewables are also to provide 43% of Greece's heating and cooling and 19% of its transportation needs by the end of this decade. Wind and photovoltaic power stations will mostly contribute to the electricity production but other types of RES such as geothermal, offshore wind farms or wave energy will only be developed gradually.
- A higher greenhouse gas emissions reduction target has been set, with a reduction of more than 42% over 1990 emissions and more than 56% over 2005 emissions – well shy of the 55% goal set by the EU.
- Concerning energy-saving initiatives, a programme for the energy renovation of public buildings, industrial facilities and residences was announced in 2020 and will enter implementation in 2021, mobilizing public and private financing.

Greece's new national energy plan mandates 7.7 GW of cumulative solar PV capacity by 2030, up from approximately 3 GW of installed capacity at present. Specifically, the plan calls for the country's total installed PV capacity to increase from 3 GW in 2020 to 3.9 GW in 2022, 5.3 GW in 2025, and 6.3 GW in 2027. For Greece's other renewable energy sectors, the new plan says that the country should also have 7 GW of cumulative wind power capacity by 2030, in addition to 3.7 GW of hydropower, 300 MW of biomass and biogas, and 100 MW of geothermal capacity. Greece's latest

statistics, published in 2020, show that it has already installed 3 GW of PV, 3.4 GW of hydro, 4 GW of wind, and 85 MW of biomass and biogas capacity. The country does not yet have any offshore wind power capacity and the new plan does not set a time line for offshore development, other than stating that 250 MW of offshore wind capacity is feasible by 2030.
In addition to the NECP, a National Strategy for the Circular Economy has been developed as a horizontal action aiming at the optimal use of resources (energy, water, raw materials) in every economic sector. Under a Green Financing Scheme a series of financing incentives is foreseen for companies investing in the circular economy and industrial symbioses, in water reuse after biological treatment etc. Green innovation concerning sustainable green investments will also be supported.

A National Strategy for Adaptation to Climate Change is also being developed, incorporating actions aiming at biodiversity conservation, a more effective water resources management, forest management etc. The NECP, among other tools, envisages investments worth €43.8 billion in renewable sources, natural gas and electricity transport and distribution networks, financial incentives for the purchase of electric cars and energy saving by 2030. National financial resources but also European funding deriving in particular from the Just Energy Transition Fund, a new EU financial instrument enhancing an energy transition that is "just and socially fair", will be used.

In June 2021, the European Commission has also adopted a positive assessment of Greece's recovery and resilience plan. This is an important step towards disbursing €17.8 billion in grants and €12.7 billion in loans under the Recovery and Resilience Facility (RRF) over the period 2021-2026. This financing will support the implementation of the crucial investment and reform measures outlined in Greece's recovery and resilience plan. It will play a key role in enabling Greece emerge stronger from the COVID-19 pandemic. The Commission's assessment of the plan finds that it devotes 38% of Greece's total allocation to measures that support climate objectives. This includes investments in upgrading the electricity network, strengthening the support scheme for producers of renewable energy sources. Furthermore, the plan supports investments in energy efficient renovations and the development of local urban plans with a focus on strengthening climate resilience of urban areas. Other measures include support for a national reforestation programme and a comprehensive strategy to strengthen the civil protection and disaster management systems that covers, amongst others, investment in flood mitigation.

Both the competitive auctions and premium tariffs are to be retained as a part of Greece's energy policy. However, the new energy plan states that the auctions need to take place under a strict timetable. Eventually, the goal is for Greece's price auctions to produce tariffs that are similar to other European states', so it can build subsidy-free renewable power plants, according to the NECP. The biggest challenge for Greek RES tenders thus far is that they have been undersubscribed, despite high interest from domestic and international investors. This is due to a lack of fully licensed projects that are eligible to participate in the auctions organized by the Energy Regulator. Greece's energy regulator (RAE) also appears unable to process the steadily-growing number of license applications in a timely manner and by prioritising more mature projects.

The government is now seeking to simplify the licensing process, so that the Regulator has a less cumbersome task. RAE accordingly published a simplified structure for Greece's licensing regime, open to public consultation. The sector is now eagerly anticipating the publication of the new policy, which is imminent. Small systems are to be included as part of Greece's new national energy plan, which envisages 1 GW of net-metered and self-consumption distributed systems by 2030. Together, they will be capable of meeting the electricity needs of at least 330,000 households. Greece's uptake of renewable energy to date has happened without the inclusion of any energy storage facilities. This has to change, according to the new plan, which argues that the country's phase-out of lignite will require a more flexible electricity system. This requires new energy storage systems and new interconnections. The plan identifies the establishment of a policy framework for energy storage as an immediate priority. With regard to new interconnections, the plan also provides for a second high voltage line to Bulgaria, upgrades to an existing line to North Macedonia, and the construction of a new line to link Greece to Cyprus and Israel (see Euro-Asia Interconnector).

One very important point for the renewable energy sector is the plan's clear mandate for island interconnections. Greek islands, which are not already connected to the mainland grid, should either be connected soon or they should embrace new hybrid power systems that use renewable energy and storage. Interconnections are already being built, with a new electricity link between the mainland and the Cyclades Islands now partly operational. The architects of Greece's new national plan want small islands to develop hybrid systems, so the country can stop subsidising polluting diesel generators by building storage systems. A pilot hybrid system is already in operation on the island of Tilos, while IENE carried out a comprehensive study for a hybrid system on the island of Kastellorizo with high RES penetration (≈95%) (17). Greece's new energy plan also provides for greater energy efficiency, electric mobility, and a competitive electricity market that could potentially bring the country's energy system on par with the latest technological and market developments throughout the world.

Romania

Romania reached its 2020 EU renewables target of 24% of gross final energy consumption coming from renewables in the 2010s with more than 11GW installed capacity coming from renewables. Solar – mostly from megawatt-scale PV plants – accounts for around 7% of installed generation capacity, compared with around 16% of wind power, 34% hydro, 18% gas, 17% coal and 7% nuclear, according to figures from the latest 10-year National Energy and Climate Plan (NECP) submitted to the European Commission. In order to reach its 2030 renewables target of 30.7%, Romania plans to add around 7 GW of new renewables capacity, of which around 3.7 GW are projected to be solar PV, according to the NECP.

As with other countries in the region, the liberalisation of the Romanian energy markets has been a slow process. The electricity market was reformed in 2018 and regulated tariffs were eliminated in the wholesale market following a liberalisation calendar adopted in 2012 (18). The country has a functional centralised market for bilateral contract, day-ahead, intra-day and the balancing market. The electricity market is fairly competitive, with a wide range of electricity producers from which suppliers can buy in a competitive setting, although the majority of producers are state-owned companies and numerous household consumers are still covered by regulated tariffs if they have not opted to participate in the competitive market.

According to the European Environment Agency, in 2018 the share of renewable energy in the gross electricity production was around 42%, while coal and lignite accounted for 24% of the energy mix, nuclear power – 17%, and natural gas – around 15%. Romania is also home to the biggest onshore wind farm in the EU and generally has good potential for offshore, in the Black Sea, according to the International Renewable Energy Agency (IRENA), in addition to significant potential for solar PV installations, including its coal regions.

Whereas almost one quarter of the electricity generation still relies on fossil fuels, significant investments will be required to support single-industry areas and coal-producing areas (e.g. Valea Jiului, the region of Oltenia), which will be impacted by the transition to a green economy. According to the National Statistics Institute, there were 11,800 workers in Romania's high-grade and low-grade coal extraction as of December 2019. Added to these jobs are the ones in the power sector which generate electricity and thermal energy using coal as a raw material.

Other factors must also be considered in order to fully assess the extent of social consequences, such as today's unemployment rate or the possibilities for occupational retraining. All these criteria show that Romania's South-Western region shall be among the most severely impacted EU areas where decarbonisation takes off. Furthermore, it should be noted that the most recent version of the country's NECP includes 1.98 GW of installed coal capacity until 2030 (approx. 7.9 percent of the total energy mix). This goes against the path adopted by a majority of EU member states to phase-out coal completely from their energy systems.New economic opportunities can also be provided by using biomass and other types of renewables (eg. offshore wind) to generate energy and by upgrading and decarbonising the energy industry. All these solutions are also closely related to the ideas presented in the National Integrated Energy and Climate Change Plan for the period 2021-2030, currently subject to public consultation. Under this plan, Romania targets an overall 30.7% share of renewable energy in its final gross energy consumption.

In this context, Romania could become the tird largest recipient of the Just Transition Fund, after Germany and Poland. Of course, this assumption is based on the premise that Romania develops the necessary projects to attract the allocated funding. These projects will have to lay down the ways in which the social, economic and environmental challenges will be addressed. The €757 million budget to be supposedly assigned to Romania will depend on the authorities' ability to develop the regional just transition plan (or plans), which will have to be approved by the EC. This will provide the guidelines for the transition process until 2030, according to the National Integrated Energy and Climate Change Plan, and it will also have to be consistent with the transition to a climate-neutral economy.

In May 2020, the Romanian government re-introduced long-term bilateral Power Purchase Agreements (PPAs) after banning them for almost eight years. The new rules were passed through an emergency ordinance in a move to shore up investor confidence in the country's renewables sector. PPAs allow for long-term bilateral OTC contracts between buyer and seller of electricity, often with a duration of 15-20 years. Such contracts will enable investors to circumvent volatility risk on the Romanian Opcom exchange, where power prices have dipped by 20-30% since the outbreak of Covid-19. Romania is also drawing up a Contracts for Difference (CfD) framework whereby the government will guarantee a strike price for investors in new renewables projects. CfDs have proven to be a useful tool in attracting investors in other countries, as illustrated by successful auctions in the United Kingdom and France.

Non-EU members

Turkey

The market for renewable energy in Turkey has been growing since the country enacted a "Renewable Energy Law" in 2005. Progress has been steady and has ramped up in recent years after renewable energy zones (REZs) were introduced in late 2016.The regulation allowed for structured investments in renewable power projects and has been supported by an incentive scheme for clean energy programs. In just over a decade, Turkey has tripled its installed renewable capacity to 46,000 megawatts and invested nearly €50 billion in renewable energy projects.

Turkey ranks sixth in Europe and 13th in the world in terms of renewable capacity. It generated 12% of its electricity from wind and solar in 2020, compared to the world average of 9,4%. Turkey now generates as much as 46% of its electricity on a monthly basis from renewable resources, most of it from hydropower. Combined local and renewable energy resources saw a total share of 64% of electricity production in the first 10 months of 2020, a record high. (19) Turkey thus reached its objective of producing two-thirds of its electricity in the short-term from local and renewable resources. That goal was set in 2017. By 2020, renewable energy installations corresponded to a 48% of the total installed capacity in the country.

Today, hydropower accounts for about 30% of Turkey's electricity production. Among renewables, hydro has about 29,2 GW of generation capacity, followed by wind -with 262 wind farms and 7.6 GW of capacity- and solar, with about 6 GW. It is expected that installed solar photovoltaic capacity will rise to about 14 GW by 2023, with solar and wind reaching a combined capacity of 30 GW by 2030. The electricity production from wind energy rose by 14.6% in October 2019 compared to October 2018, illustrating a trend that has seen it increase by 70% in the last five years. (20).

Power generation from hydroelectric plants also hit a record high in the first 10 months of 2019, according to Bekir Pakdemirli, the minister of Agriculture and Forestry. During the first 10 months of 2020, the share of resources in electricity generation was 36.3% for coal, 31.5% for HEPP [hydroelectric power plants], 17.3% for natural gas, 7.3% for wind power plants, 3.4% for solar power plants and 2.6% for geothermal power plants.

Israel

Renewable energy in Israel accounted for a minor share of electricity production, with a relatively small solar photovoltaic installed capacity (2 GW). However, there is a total of over 1.6 million solar water heaters installed as a result of pre-existing (since the 1960s) mandatory solar water heating regulations. In 2020, 70% of electricity came from natural gas, and 10% from renewables, almost all of it solar PV, representing 6% of gross final energy consumption. Still, this represented a rise in renewable electricity production from only 3.1% at the start of 2020. Israel's best month for renewables was April, which is sunnybut electricity consumption is low because air conditioning is not needed, and because many factories were closed for the Passover holiday and the coronavirus lockdown.

Israel has historically been a leader in the use of solar energy for domestic purposes. The most obvious proof is the thousands upon thousands of solar water heaters on roofs. Today, 85% of Israel's 1,650,000 households use them, saving 1.6 billion kilowatt hours each year, equal to 21% of the domestic electricity use, making Israel one of the largest per capita users of solar energy in the world. Israel ranks 4th worldwide in cumulative solar water heating installations per 1,000 inhabitants.

Since 2019, Israel installed a concentrated solar power (CSP) system in the Negev desert near the kibbutz of Ashalim region. The Ashalim solar power station consists of three plots with three different technologies. The station combines 3 kinds of energy production: solar thermal energy, photovoltaic energy, and natural gas.

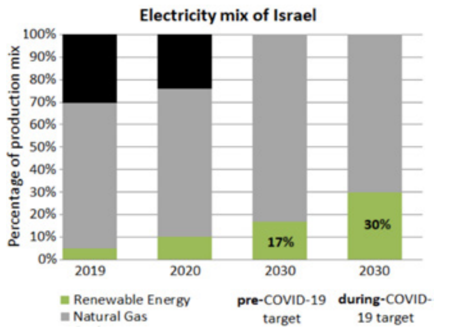
Ashalim Plot A (Negev Energy) is a 121 MW parabolic trough plant with 4.5 hours of thermal energy storage.

The Ashalim Plot B (Megalim) hosts a solar power tower. It has an installed capacity of 121 megawatts, concentrating 50,600 computer-controlled heliostats enough to power 120,000 homes. Electricity production commenced in September 2019, producing 320 GWhr of energy per year. The project was a joint venture between Brightsource and Alstom. The station was until recently the tallest solar power tower in the world at a height of 260 meters including the boiler.

Ashalim Plot C is a 30MW PV plant was commissioned in 2018, one year before the CSP plant.

Recently Israel set a goal of generating 20 percent of its electricity from solar radiation by 2025 and 30 percent by 2030. A plan by the Ministry of Energy, presented in July 2020, foresees a sevenfold increase of the cumulative solar PV capacity of Israel from currently around 2 GW to 15.77 GW until 2030. Solar PV is expected to account for the significant share of the renewable energy, and would replace the remaining coal in the electricity mix.

Figure 11.4 **Existing Renewable Energy Share between technologies as of the end of 2018**



Source: Israeli Ministry of Energy, Department of Publications

Considering Israel's enormous solar potential, the 30% renewables by 2030 target is a low bar. It makes sense for Israel to put more efforts into cutting energy-related carbon dioxide emissions and scaling up renewables. To reach a higher percentage of solar usage, Israel will need to develop an advanced storage system to accumulate enough energy for periods when the sun doesn't shine. Israel is a leader in storage installations with around 800 megawatts (MW) of committed solar plants that have an additional four hours of storage that supply electricity at peak demand hours after the sun has gone down.

There are also plans to construct hundreds of wind turbines in northern Israel. The projects were granted government approval in January 2020, boosting renewable energy production while answering security needs. The agreement will enable the development of several projects in northern Israel, which are currently in the project planning phase and will be implemented in the coming years. The plan is to establish hundreds of wind turbines in Israel's northern region, at a cost of US$72 million.

Although the rise of the renewables target is welcome, it is probably not enough to bring Israel to net-zero emissions, as current pledges have proven insufficient to meet climate goals. Israel faces an increasing electricity demand not only in the power sector but also from highly energy-demanding desalination plants and the increasingly electrified transport sector. Both transport and water sector will play a central role in setting Israel on a pathway towards climate neutrality. For the moment, Israel has decided to meet its energy demand mainly through natural gas.

Barriers for further RES development in SE Europe

There are several barriers to the development of renewable energy sources in SE Europe, including:

(a) a perception of high costs involved in renewable energy power and the need for subsidies

(b) ageing transmission and grid infrastructure that struggles to cope with large variable RES energy volumes

(c) slow and unpredictable planning processes; regulatory uncertainty as most countries are transitioning towards competitive support schemes

(d) underdeveloped day-ahead and intraday markets,

(e)limited regional market integration and a high cost of capital stemming from both the above and,

(f) lack of experience in providing funding tools and limited comfort with lending to the sector by the local banking sector.

The implementation of the European Green Deal will require some sort of regional cross-border approach. The potential for successful cooperation seems possible, judging from progress achieved in market organisation and regulation and through several initiatives. The cooperation clause under the Governance Regulation will provide additional impetus, especially as, to date, the neighbourhood rivalry mentality still remains an obstacle to co-operation and joint planning. A climate-neutral SE Europe will, by definition, require close co-operation between the EU, the Energy Community and neighbouring countries such as Turkey. Climate neutrality over time will also raise the issue of (regional) carbon leakage. Hence, a regional approach is important in order to ensure that the transition occurs simultaneously throughout the region in order to avoid, for example, the risk that

11

more ambitious countries replace domestic high carbon electricity production with other carbon-intensive imports from neighboring countries.

The potential for renewable energy in southeast Europe, including the wider Black Sea region, has been repeatedly documented, for example by IRENA and the World Bank. There is ample evidence that a combination of energy shortcomings and in particular electricity market organisation and regulation -and sometimes the lack of political will- has posed barriers to the decarbonisation of the energy mix, for example the integration of renewables, energy efficiency, storage solutions or nuclear. The persistent challenge overall is the lack of regional strategies and the competition for regional leadership, especially since only limited high-level interactions have been present in the broader geographic area. A potential expansion of common strategies, policies and initiatives beyond EU borders, for example In the Black Sea, offshore renewables development, possibly alongside hydrogen or electricity grids, may become a crucial political platform for further enhancing the dialogue for strategic steering and policy guidance, along decarbonisation objectives. The experience from existing regional initiatives can be used to further promote market opening and better prepare the region for the Energy Transition.

The potential EU climate-neutrality target for 2050 is unprecedentedly ambitious, especially for the SEE region. While all member states will face challenges in delivering the required transformational changes under the European Green Deal, it would do well for the EU to continue paying special attention to the SEE region. Given the different starting points of these countries, the state of the market and their political discourses, actual and practical solutions are needed in overcoming the existing energy market barriers.

RES Costs in SEE

Many SEE economies have often overlooked variable renewable energy technologies in their renewable energy plans, favoring the more traditional and established hydropower and biomass technologies, which were perceived as less expensive. Even with a relatively high cost of capital, solar PV and onshore wind remain cost-competitive solutions for electricity generation in the region today, compared to generation from fossil fuels.

Hydropower remains a very cost-competitive option for new power in the region. Data from the IRENA Renewable Cost Database (2019) show that the weighted-average levelised cost of electricity or LCOE from hydropower in SEE decreased by a third from 2015 to 2019. Hydropower, including both small and large applications, is still the most economically viable RES technology in the region, given the abundant resources and many years of experience in this regard. Although over 24 GW of capacity is already installed in this sector (excluding Turkey), an additional 18 GW, out of 61 GW of technical potential, could be deployed in a cost-effective manner, with an average LCOE of €56/MWh, in almost all of the countries in the region.

Wind energy is one of the most abundant renewable resources in the region, with an overall technical potential more than four times higher than that of solar PV. This potential could be additionally deployed today in a cost-effective manner to generate electricity at an average LCOE of €82/MWh, based on the medium cost of capital scenario. At most suitable locations – characterised by good resource availability and proximity to the grid – LCOE can go below €50/MWh, with the highest cost-competitive potential in Bulgaria, and Romania.

As far as solar photovoltaics are concerned, the dramatic decline in technology costs and the satisfactory irradiation levels of the region, make solar PV a viable supply option. The average LCOE for this potential is €81.8/MWh in the low cost of capital scenario.

At the most suitable locations, characterised by good resource availability and proximity to the grid, LCOE can go as low as €70/MWh, with the highest cost-competitive potential in Albania, Bulgaria, Croatia and Romania.

The technical **biomass** electricity potential in the region is more than 20 GW, while the cost-competitive potential amounts to 4.7 GW, with an average LCOE slightly below €72/MWh in the medium cost of capital scenario. Landfill gas plants are considered an attractive option throughout SEE, while cost-competitiveness in solid biomass is achieved outside of the EU only in the low cost of capital scenario (the LCOEs drop below the threshold to €88/MWh).

The **geothermal energy** potential of the region is primarily characterised by a relatively low-enthalpy resource base, which is more appropriate for non-power applications. Only binary plants, which allow cooler geothermal reservoirs to be used for electricity generation, are considered feasible options for generating electricity, which offer a potential of up to 690 MW, with an average LCOE of €86/MWh in the medium cost of capital scenario. This potential could be deployed mainly in Bulgaria, Romania, Greece and to a lesser extent in Croatia and Slovenia, while in the rest of SEE, the geothermal electricity potential is often marginal and uncertain (22). The current installed geothermal electricity generation capacity in Turkey is 1.515 MW with a total of 48 plants already in operation[3].

With the fall in costs for solar and wind technologies expected to continue, SEE could benefit greatly from further developing its vast potential, according to IRENA. Both solar PV and wind generation can be even more cost effective in SEE than shown so far in this analysis, provided access to a low cost of capital becomes easier.

Table 11.4 **Additional cost-competitive renewable energy potential in SEE**

	Low cost of capital scenario		
Technology	**Capacity [GW]**	**Average LCOE [EUR/MWh]**	**Generation [GWh]**
Solar PV	32.36	81.79	45,137
Wind	231.74	79.84	595,517
Hydropower	18.12	56.07	52,860
Biomass	9.74	73.64	55,933
Geothermal	0.72	74.73	5,100
Total	292.67	-	755,052
	Medium cost of capital scenario		
Technology	**Capacity [GW]**	**Average LCOE [EUR/MWh]**	**Generation [GWh]**
Solar PV	5.23	88.23	7,600
Wind	98.15	82.18	257,154
Hydropower	18.12	56.07	52,860
Biomass	4.70	71.63	25,962
Geothermal	0.69	86.48	4,890
Total	126.89	-	348,971
	High cost of capital scenario		
Technology	**Capacity [GW]**	**Average LCOE [EUR/MWh]**	**Generation [GWh]**
Solar PV	0	0	0
Wind	32.56	84.71	85,421
Hydropower	18.12	56.07	52,860
Biomass	2.16	71.28	12,840
Geothermal	0	0	0
Total	52.84	-	152,484

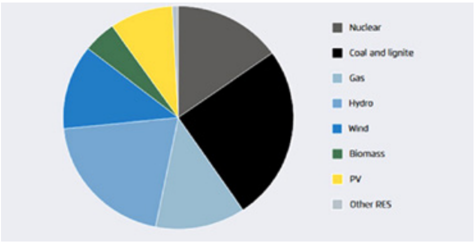
Source: Cost-Competitive Renewable Power Generation:Potential across South East Europe", IRENA, 2018

[3] Norton Rose Fullbright, "Geothermal Electricity Generation in Turkey", July 21, 2020

11.2 RES for Power Generation

With the recently adopted EU 2030 targets for climate and energy, European power systems are about to embark on a major transition. By 2030 an average of 55% of electricity in Europe's power grids must come from renewable energy sources. Now is therefore an auspicious moment for advancing a clean-energy transition in South East Europe (SEE). Countries throughout SEE have high shares of electricity generated by an ageing fleet of coal-fired power plants. Some of the youngest coal plants in the Western Balkans were built in 1988, before the break-up of Yugoslavia. Within the next decade, utility companies and governments will have to decide whether to modernise or replace roughly 50% of the region's existing coal and lignite generation capacity. Indeed, the recent SEERMAP[4] project has demonstrated that deployment of renewable capacity in EU SEE and the Western Balkans is not only feasible but also has several advantages over fossil fuel-based investment. It is estimated that solar photovoltaics (PV) and wind power – driven by significant cost reductions – will almost certainly contribute to more than half of the RES-E share in Europe by 2030. As wind and solar depend on weather, future power systems will be characterized by fundamentally different generation patterns from those observed today, significantly increasing the need for flexibility in the non-intermittent part of the power system. In meeting the flexibility challenge, regional co-operation and cross-border power system integration offer important ways forward.

Figure 11.5 **Anticipated Power Generation mix in SEE in 2030**



Source: SEERMAP Decarbonization Scenario, REKK (2017) (Albania, Bosnia, Serbia, Croatia, Montenegro, Kosovo, N. Macedonia, Greece, Bulgaria, Romania)

The most important change for the region is the sharply falling share of coal- and lignite-based generation. Compared with 2017, it is forecast that less than half of the production from these fuels will remain in the system by 2030 (20). The reduction will be compensated by an increase in RES generation of 20 TWh, in natural gas-based production (25 TWh) and in nuclear generation (11 TWh). The region will move from a net export to a net import position, but the yearly net import ratio will remain relatively small – 6.8%.

The capacity mix changes significantly in the decarbonisation scenario, with a shift away from fossil-based capacity towards renewable capacity. The changes are driven primarily by rising carbon prices in EU countries and decreasing renewable technology costs. It is assumed that limited capacity of new fossil-based generation is installed in SEE over the coming years, due to adverse economic and environmental conditions: increasing carbon prices, rising coal and natural gas prices and deteriorating utilisation rates of fossil fuels.

On a country-level, Bosnia and Herzegovina, Bulgaria, Kosovo, North Macedonia, Montenegro and Serbia tend to become net importers of electricity due to a strong decrease in coal- and lignite-based generation and a smaller increase in RES generation. Meanwhile, the net export positions of Greece and Romania will increase because the decreasing coal- and lignite-based generation will be more than compensated by natural gas, RES-based generation and nuclear.

According to the South East Europe Electricity Roadmap (SEERMAP) Decarbonisation Scenario, the utilisation rates of the different types of power plants will have changed significantly by 2030, with the utilisation of natural gas plants climbing to 40% from 7.5% in 2017 and the utilisation of hard coal-fired plants growing from 20% to 34%. At the same time, the utilisation rate of lignite-fueled plants is projected to fall sharply in Europe and in the SEE region, down from 81% to around 68%, due to deteriorating economic performance and

[4] SEERMAP (2017), "South East Europe Electricity Roadmap", http://rekk.hu/downloads/projects/SEERMAP_RR_SEE_A4_ONLINE.pdf

reduced operating hours. The most important change between 2017 and 2030 is that more and more power plants will be operated in "peak load" mode: natural gas power plants with low yearly average utilisation rates and a high number of start-ups (up to 35 times/year). For comparison, the highest number of modelled start-ups for a given unit in 2017 was less than 20 in SEE. According to SEERMAP by 2030 more than half of the gas-fired units will actively participate in the intraday and balancing markets. Likewise, the utilisation structure of coal and lignite plants will change by 2030 – increasingly operating in a "flexibility services mode". This confirms their changing role and utilisation pattern in the future electricity system: they will provide more system balancing and flexibility services and receive more of their income from short-term power markets instead of from baseload energy sold on the futures and day-ahead markets.

With roughly half of the installed hard coal and lignite generation capacity in SEE requiring modernization or replacement over the next years, the region now has an excellent opportunity to advance its efforts for large global RES applications and, thus, fall in line with the EU's 2030 targets for climate and energy.

Most studies and scenarios show that 50%+ of RES share is realistic in terms of system flexibility, RES integration and security of supply. Energy policy makers believe that a diverse mix of flexible generation technologies in SEE (hydro technologies, flexible biomass, natural gas and storage) can facilitate the integration of RES – especially wind and PV. However, the promising potential of wind, solar PV and biomass is not yet reflected in the energy policy of most of the SEE countries. Only Turkey, Greece, Romania and Bulgaria are exhibiting an emerging trend towards alternative renewable energy sources.

In particular, reduced flexibility needs and increased system reliability can be achieved by integrating countries and regions with fundamentally different weather regimes. A fully interconnected SE European power system would be highly beneficial for RES penetration. Indeed, regional co-operation, stronger power systems and market integration will help minimize power system costs for consumers while maximising supply security.

Interconnections and market integration are key factors for maximising security of supply and providing the required flexibility for RES deployment in SEE. In the case of increased network limitations, only a small part of non-satisfied demand can occur in countries with network limitations (Albania, Kosovo and North Macedonia). This underlines the importance of continuing the implementation of the planned cross-border infrastructure developments. More importantly, market integration must be deepened among SEE countries in order to use available cross-border capacities efficiently. This not only brings security of supply benefits; it also has an economic rationale, as it gives the region greater access to the electricity markets of neighbouring countries in Central and Eastern Europe. Most importantly, SEE can provide flexibility services to these countries in seasons/years with higher levels of hydro availability.

Table 11.5 **Power generation from RES in SEE (excluding Turkey) and Crossborder electricity trade**

		2017	**2018**	**2019**
Power Generation from RES [GWh] *excluding Turkey	Hydro	52832	72821	58539
	Wind	16879	16633	19318
	Biofuels	4226	5525	7242
	Solar PV	8172	8092	9179
	Geothermal	0	2	73
	Volume of electricity crossborder flows inside SEE	130885	138073	117325
Crossborder electricity trade in SEE region [GWh]	SEE's Electricity exports (-> IT, AT, SK, UA)	6570	9320	5407
	SEE's Electricity imports (<- IT, AT, SK, UA)	28557	21191	29770

Source: IEA, Entso-e, IENE

11.2.1 Hydro Power

The SEE region has the largest remaining unexploited hydropower potential in Europe. However, the development of this untapped potential is causing growing environmental concerns, on account of its diverse effects on geomorphology and biodiversity. Nevertheless, the number of awarded concessions has been rapidly increasing in the last few years and today a few thousand new hydropower plants are in the pipeline in the whole SEE region. On the other hand, potential renewable energy sources have yet to emerge as a dominant force in most of SEE, with many countries still focusing on hydropower rather than on wind, solar and biomass.

Over the last two decades, Southeast Europe has experienced a wave of new hydropower projects. Albania has been the most active in hydroelectricity, awarding 183 concessions for no fewer than 524 hydropower plants since 2002 – although environmental concerns led to the cancellation of a series of dams on the Vjose river in 2021. Lately we have seen an upsurge of hydropower plant in construction in Bosnia and Herzegovina, Kosovo, North Macedonia, Montenegro and Serbia.

The SEE countries (excluding Turkey) currently have an installed hydropower capacity of more than 15 GW (2020) with an electricity generation of about 35TWh/a. The average share of hydropower in the yearly electricity consumption is about 21%. However, due to fluctuating hydropower supply the contribution of hydropower to demand varied between 16% and 25% in the years 2011-2018. On a country level, the average share of hydropower in demand ranged between 10% in Greece and 88% in Albania (21).

Since 2005 at least 82 plants have been financed in the region by multilateral development banks. The European Bank for Reconstruction and Development (EBRD) has been the most active player (61 greenfield plants supported with some €126 million). The European Investment Bank (EIB) has provided the largest amount of financing by volume (€445 million for 11 plants). Between 2010 and 2017, about 1.7GW of additional hydropower capacity was put into operation. However, another 1.5GW is required in order to meet the combined 2020 NREAP targets for hydropower in SEE countries (excluding Turkey).

The available hydropower potential adds up to a total economically feasible capacity of 12.8 GW (37 TWh/a) and a total technical potential of 25.2 GW (65 TWh/a), respectively. The countries with the highest remaining potential are Albania, Bosnia-Herzegovina and Greece. The number of awarded concessions has been rapidly increasing over the last years and today about 2,800 new hydropower plants of various sizes are in the pipeline for construction in the whole SEE region.

However, the expansion of hydropower has caused increasing environmental concerns in view of affected river stretches, which have a high ecological value. Infrastructure works potentially threaten the river ecosystems in terms of hydromorphology and biodiversity. For example, a published study (Schwarz, U., 2017: Hydropower Projects on Balkan Rivers Data Update 2017. Study on behalf of Riverwatch and Euronatur) concluded that 37% of the planned projects in the SEE region are to be found in protected areas.

However, even if hydropower is still the most economically viable renewable energy technology in the SEE region, wind onshore and solar PV have already reached a competitive cost level, and could, in principle, substitute for ecologically sensitive hydropower projects without major economic disadvantages. Furthermore, a greater consideration of wind, solar PV and biomass in renewables portfolios would help diversify the electricity energy mix and make it less vulnerable to unavoidable seasonal and yearly fluctuations of electricity generation from hydropower.

In short, the assessment of hydropower projects should not only be based on ecological but also on energy and economic aspects, which consider the interaction of hydropower projects with the electricity system. For example, hydropower plants that are combined with a reservoir can provide flexible generation and ancillary services. In the coming years flexibility in a power system is expected to gain importance, especially if the share of variable generation from wind and solar increases. Hence, a more differentiated classification of hydropower projects is recommended that would allow for a transparent and equal consideration of energy economic and environmental aspects.

Albania

The country's domestic generation is almost entirely dependent on hydropower –in 2019 the total installed capacity reached about 2.210MW of which only 100MW was thermal. Besides hydropower no other renewable technology has yet been installed on any scale (except a few photovoltaic plants) despite the Ministry of Infrastructure and Energy's stated resolve to speed up the selection process for the construction of the largest solar PV plant in the region with an installed capacity of 50MW. As the only oil-fired power plant has been out of operation for some time, the share of renewables in total electricity generation is still 100%. Although the total installed hydropower generation capacity has increased over the last 8 years by about 500MW, Albania is still highly electricity import-dependent, particularly in drought years. Depending on the available water supply hydropower production can vary significantly. The capacity factor ranges between 24% (2018) and 48% (2013), which equals to annual full load hours of 2,100h/a and 4,200h/a, respectively. (Capacity is defined as annual generation divided by installed capacity and 8,760 hours). Security of supply, therefore, remains a challenge.

Among the new projects is Devoll Hydropower, which consists of two hydropower plants, Banja and Moglicë, in the valley of Devoll on the Devoll River, with a total installed capacity of 256 MW. Devoll Hydropower was initially a 50/50 joint venture between Norway's Statkraft and the Austrian energy company EVN. Statkraft in 2013 acquired EVN's 50% share and is now 100% owner of project.

In June 2020, the Moglicë hydropower plant went on stream. Moglicë is the largest of the two hydropower plants in the Devoll hydropower project and will generate approximately 450 GWh per year. Together with the Banja hydropower plant, the Devoll valley hydropower projects will reach 700 GWh per year, equal to approximately 13% of Albania's total electricity generation.

Other hydro projects underway include the Skavica plant on the Drin. The Kalivac and Pocem projects on the Vjosa River were struck duwn by Albania's Supreme Court in 2021 on environmental grounds.

Bosnia & Herzegovina

Bosnia-Herzegovina has a total installed generation capacity of 4.5GW (2019), of which 2GW is coming from hydropower including pumped storage. Hydropower capacity has increased by about 130MW over the last six years and in 2016 some 300MW of new lignite generating capacity was commissioned – the latter increased the output from lignite power plants by 2TWh to 10.5TWh in 2016 and 10.8TWh in 2017.

Consequently, the share of renewables in total electricity generation dropped in 2016 on a year-on-year basis from 40% to 34%. Due to an exceptional drought the share of renewables in the total generation further plunged to 24% in 2017. Despite the strong dependence on hydropower, Bosnia-Herzegovina is the only power exporter in the Western Balkans. However, hydro conditions have been affecting the actual import-export balance in recent years. Depending on the water supply, hydropower production can vary significantly. Bosnia and Herzegovina also has substantial hydro pumped storage capacities but according to ENTSO-E statistics, the pumped storage plants have only been operated for a few hours in the past years. Power consumption has not changed much in recent years and was at 12.9 TWh with a peak load of some 2,240 MW in 2018. Generally, the annual demand has been mostly affected by economic and weather events.

Bulgaria

Bulgaria has a total installed generation capacity of 12.0 GW (2018), including 4.5 GW lignite and hard coal, 2.0 GW nuclear, 0.6 GW natural gas, 3.2 GW hydropower including pumped storage and 1.8 GW of various renewables. Hence, the generation mix depends primarily on domestic coal and nuclear.

The country also has substantial hydro (storage) capacities and unlike most other SEE countries has considerable wind and solar capacity installed due to a successful five-year implementation of feed-in tariffs. Nevertheless, the share of renewables in total electricity generation is still comparatively low and was approximately 14% in 2018. Hydropower has shown a relatively slow growth rate in the past 6 years with a net addition of only some 50 MW.

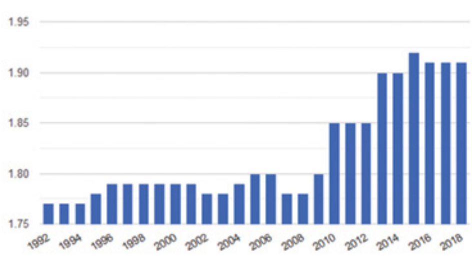
Capacity growth in the upcoming years is expected to come mostly from renewables and gas to substitute old and inefficient fossil fuel-fired thermal plants. Depending on the available water supply hydro-power production can vary significantly. For example the range of the capacity factor in the years 2011-2018 was between 13% and 20%, which corresponds to 1,200h/a full load hours and 2,400h/a, respectively. However, since the contribution of hydropower to the total annual electricity generation is relatively small – on average 11% in the years 2011-2018– and the generation portfolio is well diversified, security of supply is generally not affected from the availability of hydropower capacities. Bulgaria is well-supplied with power compared to its demand needs and is a strong regional power exporter.

Croatia

Croatia has four major hydroelectric plants in two main parts of the country – the Varazdin hydro plant next to the Slovenian-Hungarian border and the Senj, Obrova, and Zakucac plants along the Adriatic coastline. All of them are owned and operated by the national electricity company, Hrvatska Elektroprivreda (HEP). The 486 megawatt (MWe) Zakucac hydroelectric plant is the largest power plant in Croatia, and is scheduled for renovation to improve its operability. A tender has been announced for the new 68.5 MWe Ombla hydroelectric plant proposed for a site on the Rijeka Dubrovacka river. Two additional hydropower plants have also been proposed, the 106 MWe Virje plant and the 42 MWe Lesce plant.

The Croatian electric power transmission system is owned and operated by HEP. The electricity distribution grid has three different voltages; there are 903 kilometers of 400-kV lines, 1,224 kilometers of 220-kV lines, and 4,760 kilometers of 110-kv lines. There are also five 400 kilovolt (kV) substations, fifteen 220/110-kV substations and 140 110-kV substations. The average hydroelectric production of Croatia during the period 1992 - 2018 was 1.82 million kilowatts with a minimum of 1.77 million kilowatts in 1992 and a maximum of 1.92 million kilowatts in 2015. In 2018 hydropower generation was 1.91 million kilowatts and the installed capacity from hydroelectricity was 2.200 MW.

Figure 11.6 **Croatia – Hydroelectricity Electricity Production (m/KW)**



Source: The Global Economy.com

Greece

According to ENTSO-E data Greece had a total installed generating capacity of 20.7 GW in 2020 including 3.9GW lignite, 4.9GW natural gas, 3.4GW hydro-power including pumped storage and 7,1 GW other renewables. Additionally, some 2.3 GW of generation capacity are installed in the non-interconnected islands (NIIs), which are mainly supplied from diesel-driven generators and some renewable energy. Besides Romania and Turkey, Greece is the only SEE country with a substantial portfolio of renewable energy. Wind, solar and biomass

were representing a generation capacity of 7GW at the end of 2020 and have already exceeded the country's hydropower capacity.
In contrast to the strong growth rates of other forms of renewables, hydropower capacity additions over the past 8 years were minimal. The total hydropower capacity reached 3,409 MW in 2019. From 2008 to 2019, total hydropower capacity increased only by 233 MW. As in other SEE countries the contribution of hydropower to the national generation mix varies significantly over the years. The bandwidth of the hydropower capacity factor was between 17% (2017) and 27% (2015) and of the full load hours between 1,500h/a and 2,400h/a, respectively. Greece has been a net importer of electricity for several years but in 2014 imports sharply increased to about 18% of annual consumption due to a significant decrease of electricity production from domestic lignite.

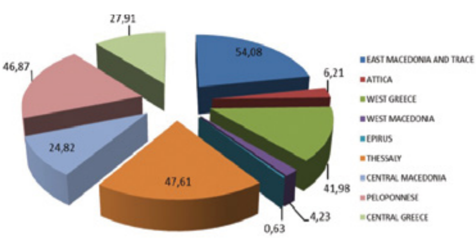
The biggest part of RES-generated energy in Greece comes from large hydropower plants. Today, 15 such plants of approximately 3 GW capacity are in operation in Greece and with an average annual production of 4,160 GWh. The Public Power Corporation (PPC) owns and manages all of these power plants located in the rivers Nestos, Aliakmonas, Edessaios, Aoos, Acheloos, Tavropos, Arachthos and Ladonas. The hydroelectric stations in Sfikia and Thisavros and the rivers Aliakmonas and Nestos respectively, act as reversible-pumping stations. They store water in their reservoirs by pumping at hours of low demand, and the water is released to produce electric power during hours of high demand, thus contributing to the normalization of peak daily load curve resulting in both the ability to cover the increased energy needs of particular times and to reduce costs (optimization of energy balance).

The PPC is now scheduling the integration of new hydroelectric power plants at Metsovitiko (29 MW) and Mesohora (160 MW) and it also plans two smaller scale hydroelectric power plants in Mesochora (1.6 MW) and Papadia (0.50) MW. The PPC also operates 17 small hydro power stations in different parts of the country with a total installed capacity of 65,35 MW.

In the National Interconnected Electricity System on 31.12.2020, 126 small hydro power plants (SHPPs) were in operation with a total installed capacity of 245.25 MW. Over the last 3 years (2018-2020), the average annual energy production of the sector was 649 GWhs. According to official data provided by DAPEEP SA, in 2020 (Nov), SHPPs represented 3.29% of the total installed capacity of RES installations, contributing 3.53% of total RES energy production, while they were reimbursed with 2.20% of the total payments of the Special RES Account (E.L.APE.).

The figures regarding SHPPs in 2018 were as follows: participation in the total RES energy production was 4.27%, and participation in total payments stood at 3.65%. The difference between 2018 and 2020 (Nov) is clearly due to the fact that the installed capacity of SHPPs increased only by 1.65% during that period, while the total installed capacity of all RES in the country increased by 24.18% (mainly due to new PVs and wind installations). For RES, the most important goal is the attainment of constant low cost energy production within a relatively stable framework (i.e. non stochastic to a large extent) with SHPP's capable of meeting such a production profile. It appears that today's growth of SHPPs is very small, which runs contrary to their great potential. The technical and economic potential of SHPPs in Greece is estimated at around 2,000 MW, which means that only 12% of this capacity has been exploited; a figure that is very far from the average exploitation of the sector in the EU-27, which in some cases reaches 90%.

Figure 11.7 **Allocation of Installed Capacity (MW) of SHPPs in operation, in Greece's Interconnected System on 31.12.2020 per region of Greece**



Source: Hellenic Small Hydropower Association (HSHA)

The National Action Plan for Energy & Climate (ESEK, NOV19 version), sets as a national goal for 2030 vs 2020 regarding SHPPs an increase in their capacity of +300 MW, and this increase is in combination with Large Hydro.

Kosovo

Overall, the hydropower potential of Kosovo is limited. Kosovo is poorer in water resources compared to other countries in the region. There is a hydropower plant installed named Ujmani, with a rated power output of 35MW, and some small hydropower plants, such as Lumëbardhi, Dikanci, Radavci and Burimi, which contribute to electricity generation with 8.08, 4.02, 1.0 and 0.95 MW respectively. Other small hydropower plants, such as "Belleja", "Deçani", "Brodi II", "Restelica I and II", "Albaniku II", and "Brezovica", which were recently put into operation, have installed capacities: 8.06, 9.80, 4.8, 2.28, 4.267, and 2.1 MW, respectively.

There are some other mini hydropower plants, which are not connected to the electrical grid, but they are used for standalone (off-grid) applications. Except for water energy resources, other RES which are connected to the power grid include wind and photovoltaics, with limited installed capacities of 33.75 MW and 6.602 MW, respectively. The main rivers with hydro potential are: Drini i Bardhë, Ibri, Morava e Binçës and Lepenci.

North Macedonia

North Macedonia has a total installed generation capacity of 2.0 GW (2020), of which 0.7GW lignite, 0.4GW natural gas and oil, 0.7GW hydropower and 37 MW wind and 26 MW solar. Whereas significant lignite capacities have been decommissioned in the past years, gas-fired CHP (combined heat and power) capacities have been added to the generation system. Also, the installed generation capacity of hydropower has increased by some 170MW in the last 6 years. Hence, the share of renewables in total electricity generation increased to 34% in 2016, from about 20% at the beginning of the decade. However, in 2017 the share of renewables dropped in electricity generation to 22% due to the exceptional drought and low electricity generation from hydropower. Based on ENTSO-E statistics, total power consumption has significantly and constantly decreased in the last few years. Beside the collapse of the energy-intensive industry a major reason for such an extraordinary reduction of electricity demand was probably the reduction of non-technical losses from power thefts and non-collections in the distribution grid. Despite the strong reduction of national energy consumption, North Macedonia is still highly dependent on electricity imports. In 2019 about 30% of the consumed electricity was imported from neighbouring countries.

Montenegro

Hydropower plays a key role in Montenegro's electricity mix. The country has a total installed generation capacity of 1.0GW (2019), of which, 0.7GW hydropower, 0.2GW lignite and 0.1GW wind. In the last few years, no major fossil and hydropower capacity additions have taken place. Despite the recent reduction of energy consumption Montenegro is still dependent on electricity imports. In 2018 about 33% of the consumed electricity was imported from neighbouring countries. Only in years with a very high production from hydropower has Montenegro been a net exporter of electricity, e.g. in 2013. Generally, hydropower production in the years 2011-2018 had a capacity factor between 17% (2018) and 47% (2013) equal to full load hours of1,500 and 4,200h/a, respectively. Montenegro has abundant water resources, despite its relatively small size. Two large hydropower plants, Perućica (307 MW) and Piva (363 MW) provide for approximately three-quarters of domestic power supply, but account for only 18 per cent of total hydropower potential. There are currently 27 projects being implemented on some 25 watercourses, totaling 83 MW. The country also signed an MoU with Norinco International Corporation Ltd, a Chinese Company, to explore the possibility of developing four new hydropower plants on the river Morača with a combined installed capacity of 238 MW.

In 2020, the government awarded a concession to the State-owned power producer Elektroprivreda Crne Gore to build the hydropower plant at Komarnica and operate it for up to 60 years. The first large hydropower project in four decades, it is planned to have 172 MW and an annual output of 213 GWh. The dam at the Lonci site should be 171 meters high and the reservoir's surface is set to reach 818 meters above sea level. The hydropower plant Komarnica will cost up to EUR 290 million, more than in the previous official estimate.

However, in February 2021 the Montenegrin government said it terminated concession contracts for seven small hydro plants in the northern part of the country, and that five of the investors already filed lawsuits against the state. There has been a number of protests in the country over hydropower plants in recent years, most recently on the Bukovica River in the central Savnik municipality where local residents are manning protests in shifts and blocking excavators. The government said they will have to pay compensation to investors, accusing former authorities of approving spontaneous hydropower construction planning.

The government of Montenegro has decided to suspend the procedure for the approval of new small hydropower plants (SHPPs) until the contracts concluded so far are reviewed. The government has further agreed to suspend the approval process for the construction of a small hydropower plant at Slatina on the Slatina river in the municipality of Kolašin, as well as new small hydropower plants, until the revision of the procedure and the legality of concession agreements for small hydropower plants is completed.

The government has already terminated four contracts for the construction of small hydropower plants on the Rastak, Rezevicka and Ljeviska rivers in northern Montenegro, accusing the investors of failing to meet the terms of their contracts. It proposes to cancel another three contracts, review all concession agreements and introduce a ban on such plants in the future. Of 85 small hydropower plants for which authorities have signed concession agreements, 42 are privately owned, 24 of which are already in operation and 18 are under construction. In 2018 alone, the state paid out 7.3 million euros in subsidies for 15 small hydropower plants that provided 2.6 per cent of the electricity that year. Under Montenegrin law, the government can review concession agreements and privatisations and terminate contracts if the contractor has not fulfilled its obligations or the deals were agreed based on inaccurate data. The state officials who have signed such contracts may also face criminal charges.

Romania

Romania has traditionally had the third-lowest energy dependence rate in the EU, due to natural gas and oil reserves and to an outsized electricity production system. Yet several times the country has shifted from electricity exporter to net importer, because drought affected its hydro power generation.

Romania's electricity mix is one of the most balanced in the European Union, with coal, hydropower, natural gas, nuclear energy and wind power having comparable shares of capacity and power generation. With the exception of wind and solar, almost all units in the systems are fairly old. Thus, although there is an official installed capacity of 22GW, the average power delivered to the system is around 7GW, with many experts believing that a demand above 11GW is hard to cover relying exclusively on indigenous resources. The installed capacity of hydropower represents nearly 30% of Romania's total installed electricity generating capacity.

The country's hydropower potential is substantial, but only about 6,6 GW is currently being used, with estimated additional potential of more than 9 GW. Currently, electricity generation in Romania is largely based on fossil fuel thermal power plants, with important input from hydro plants, but also from nuclear. With its many rivers, Romania has great potential for hydroelectric power, but the current generating capacity only contributes to a relatively small amount of Romania's power needs.

The total hydroelectric power potential is about 40 terawatt-hours (TWh) per year of which 12 TWh per year has already been developed. There may be as many as 5,000 locations in Romania that are suitable for the installation of small hydroelectric power plants.

Serbia

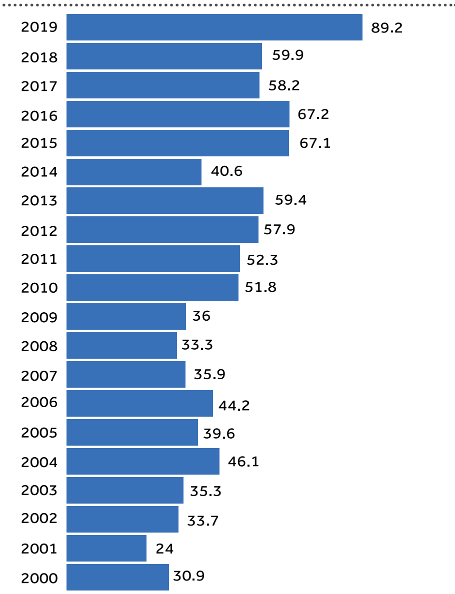
Serbia has a total installed generation capacity of 8.5GW (2020), including 3.0GW hydropower and pumped storage. Hydropower has shown a relatively slow growth rate in the past years with a net addition of some 130MW. Despite growing concerns about environmental impacts and climate change, capacity growth in the upcoming years is expected to come from domestic lignite. Old and inefficient lignite power plants are set to be decommissioned construction of renewable capacity is planned. Since hydro plants in large rivers with comparatively small annual fluctuations of water supply (e.g. Danube) dominate Serbia's hydropower production, the contribution of hydropower to the national generation mix shows a significant lower annual variation compared to other SEE countries. The range of the capacity factor in the years 2011 to 2017 ranged between 43% (2017) and 52% (2014), which equals to full load hours of 3,700h/a and 4,600h/a, respectively.

Besides Bulgaria and Bosnia-Herzegovina, Serbia is the only SEE country which has had a balanced or positive power balance with neighbours. Only in 2014, when heavy floods negatively affected lignite generation, did Serbia become a net importer of electricity.

Turkey

Turkey is the second country in Europe and the ninth country worldwide to have the largest installed power generated from hydroelectric power plants (HEPP). With newly-inaugurated plants to start operating at full capacity, it will reach first place in Europe by 2023. According to the 2020 Hydropower Status Report published by the International Hydropower Association (IHA), China is the world's largest HEPP market with an installed power of 352.260 megawatts (MW). Brazil comes second with 104.139 MW, the U.S. third with 102.745 MW, Canada fourth with 81.386 MW and India fifth with 49.917 MW. Turkey took ninth place on the list with a total of 28.358 MW installed power, followed by France with 25.519 MW. Turkey's installed capacity, which was 28.358 MW in January 2020, reached 29.193 Gigawatt electrical (GWe) as of June 2020, with the new power plants entering into operation during the first five months. Turkey's HEPP installed power is expected to exceed 31,000 MW at the end of 2020 and climb to 32,000 MW in 2021 following the full capacity commissioning of recently inaugurated dams, including Ilısu, Çetin, Alpaslan 2 and Gürsöğüt. Turkey's annual electricity generation from renewable sources reached a new record of 132 billion kilowatt-hours (kWh) in 2019. Of this, hydroelectricity generation accounted for 88.641 billion kWh, also a record. 2019 also saw daily and monthly hydroelectricity generation records realized in May with 401.3 million kWh and 11.5 billion kWh, respectively. According to Turkey's Solar Energy Investors Association (GÜYAD), Turkey generated around 44% of its electricity from renewable resources last year - consisting of 29.47% from hydropower, 7.13% from wind, 3.18% from solar energy, 2.74% from geothermal energy and 1.34% from biomass and others.

Figure 11.8 **Hydro energy generation in Turkey from 2000 to 2019 (TWh)**



Source: www.statista.com

11.2.2 Wind Energy

SE Europe has a vast potential for the further utilisation of wind energy. Currently only a small share of that potential has been deployed except in Turkey, Greece, Bulgaria and Romania. The region has a significant transformation potential towards a low carbon energy system and wind energy represents a significant share.
Wind power plant development in the Western Balkans is still limited and the whole region is characterized by a huge untapped wind generation potential. Although wind speeds are not as high as in the other countries of the region (Turkey, Greece, Romania), the Western Balkans offer many promising sites for wind utilisation. Particularly in the high mountainous regions, which have stronger and more consistent wind speeds. The number of wind power plant projects is quickly increasing. According to Wind Europe, 500 GW of wind potential is available in South East Europe, which currently is not being tapped (22).

The main non-hydro renewable source in the region is primarily wind energy. Serbia and Montenegro are in the forefront of wind utilisation and they claim the first wind farms, which were launched in the past three years. Especially, the largest wind farm in the West Balkans, Čibuk 1, was inaugurated in Serbia in October 2019, with a capacity of 158 MW. WBEG has invested 300 million euros in the construction of the wind farm, located 50km from Belgrade and equipped with 57 turbines, which is expected to supply 113,000 households with electricity. In Bosnia, the first wind farm was launched in 2018 and two others are under construction, while in North Macedonia Bogdanci remains the only wind power farm in operation. Administrative barriers result in long project development periods for wind energy projects as is the case in Bosnia and Herzegovina, Kosovo and Serbia. Such delays lead to a higher risk perception by investors while it slows power plant deployment and increases transaction costs. A series of abrupt and retroactive changes to national support schemes since 2013 have pushed up risk premiums on onshore wind projects to as much as 12%, compared to 3.5%-4.5% in North West Europe, resulting in higher prices for governments and consumers in the region.

Albania

Albania offers a very attractive wind energy potential. Although wind energy licenses in Albania correspond to approximately 2,548 MW, with an energy generation potential of around 5.7 TWh/year, today not a single wind farm project is in the pipeline for construction or already completed. Due to relatively satisfactory wind speeds (3.3-9.6 m/s), there is high, untapped potential for the deployment of wind energy more than 7 gigawatts (GW), that is more than three times its total installed electricity capacity, according to the International Renewable Energy Agency (IRENA). Around 616 MW of this wind energy is deployable by 2030. The first proposals for investments in wind farms were submitted to the Albanian Ministry of Energy and Infrastructure in May 2018 by EURUS Ltd and WF ENERGY Ltd. Investors say the optimal site for the location of the wind farm is a 450,000 square meters area in Karaburun Peninsula, in the area of Vlora.

The Albanian Energy Regulator (ERE) in August 2017 set a regulated tariff for wind projects with capacity of up to 3 MW and for PV projects with a capacity of up to 2 MW. Additionally, in July 2019 the government approved a project to build a wind farm with an installed capacity of up to 3 MW in Topoje village, near the southwestern city of Fier, a project to be undertaken by local company Max Energy. On December 2020, the government announced plans for the launching of the first tender for the construction of utility-scale onshore wind power plants, «which will make a major contribution to improve the country's future energy supply and significantly reduce greenhouse gas emissions». The tender, expected to be launched in late 2021[5], and is to be backed by the European Bank for Reconstruction and Development (EBRD) with additional financial grant support of €650,000 provided by the Swiss State Secretariat for Economic Affairs (SECO)[6].

[5] No tender launched yet
[6] https://www.ebrd.com/news/2020/albania-announces-plans-to-launch-tender-for-first-wind-power-plants-.html

Bosnia-Herzegovina

BiH has the potential to 2,000 MW of wind energy, primarily in the areas of Livno, Tomislavgrad, Mostar and Trebinje. The country's first wind farm near the Federation town of Tomislavgrad began operating in March 2018. The 82 million euro ($101.1 million), 50.6 MW wind farm has 22 wind turbines and an annual output of about 165 GWh. A second wind farm in Jelovaca of 36 MW installed capacity was commissioned in 2019. Since then one more wind farm has been completed in Podvelezje at 48 MW, raising the total wind installed capacity in B&H to 135 MW. Early in 2020 the government of Bosnia's Federation entity gave preliminary approval for the launch of the Ivovik and Orlovaca wind farm projects in the western municipality of Livno. In particular, the Federation government granted its preliminary consent to the Ministry of Energy to issue permits to Sarajevo-based company Ivovik and Livno-based HB Wind for the implementation of the respective projects. The Ivovik plant will comprise 42 wind turbines of 2 MW each and will produce 236,631 GWh of electricity per year. The Orlovaca wind farm, to be developed by HB Wind, will comprise 13 turbines of 3.3 MW each and will produce 99,060 GWh of electricity per year.

Another project, the Podvelezje wind farm, (48 MW installed capacity) is expected to be commissioned in the first quarter of 2021, with an estimated annual electricity production of some 130 GWh. A fourth project is the wind farm planned in the Ostrc site, one of the best locations for the construction of wind farms in BiH. The Ostrc wind power plant will comprise eight wind turbines with a total capacity of 28.2 MW. In view of the above projects B&H is likely to have more than 250 MW of installed wind projects by 2021.

Bulgaria

Bulgaria has 700 MW of wind power installed today, covering just 4% of its electricity demand. That capacity generated 1,450 GWh in 2019 which represented 3.23% of the whole power output of the country for that period. Bulgaria's wind potential is excellent but largely untapped (especially alongside the Black Sea coast), making Bulgaria one of the top potential candidates for investments in the region. However, the existing regulatory framework has hindered the development of renewables since 2011. This also means that existing wind farms are struggling financially, for example by paying grid balancing charges of up to €24/MWh (retroactively introduced). Bulgaria's largest wind farm is the 156 MW Saint Nikola, operated by AES Geo Energy. The Saint Nikola wind farm located near the town of Kavarna, on the Black Sea coast consists of 52 turbines of 3 MW each. It was built in 2009 and commenced operation in 2010.

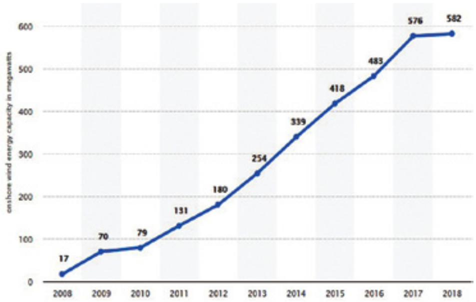
In line with the EU strategy for offshore renewable energy, Bulgaria is planning a fivefold increase in its wind capacity between 2030 and 2050, according to the Bulgarian government's draft "Sustainable Energy Strategy to 2030 with a horizon of 2050". According to the strategy, Bulgaria's wind capacity will be around 950 MW in 2030, which is slightly more than current levels. Hence, a foreseen increase to 4,500 MW installed capacity by 2050 is related to planned investments in offshore wind, a technology that Bulgaria is not currently utilising.

This planned increase in electricity production using wind sources (from the current level of 1,450 GWh to 16,660 GWh) will place this technology alongside nuclear and biomass/EfW in terms of importance by 2050.

Croatia

In 2019, a total of 12,120 GWh of electricity was produced In Croatia, of which 1,433 GWh (11.8%) by wind farms. Croatia has 28 wind farms (2020) with a total capacity of 738 MW, of which 26 operate under a feed-in tariff regime (718 MW), while two wind farms operate on a free market basis (since their twelve-year contracts have expired). In accordance with the current legislation, the total quota of all wind farms which will enter the support scheme in the coming period is 1,050 MW. It is anticipated that wind power will undergo maximum growth during the current period (2019-2021) and by 2030 it is expected to double in capacity and reach 1.4 GW.

Figure 11.9 **Onshore wind energy capacity in Croatia from 2008 to 2018 (MW)**



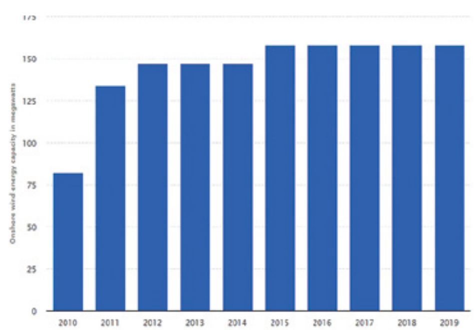
Source: Statista 2020

in Larnaca, while in November that year Ketonis Developments LTD, put into full operation the Alexigros Wind Farm with 31.5 MW also near in Larnaca. In March 2012, the Kambi Wind Farm (2.4 MW) by Aerotricity LTD was put into full operation in Farmakas in the province of Nicosia. One month later, Moglia Trading LTD started operating the Kosi Wind Farm of 10.8 MW outside Larnaca and in May 2015, the 10.8 MW Agia Anna Wind Farm in Larnaca was put into operation by Aeolian Dynamics. It is worth mentioning that the Windmill Sanida / Kellaki 10 MW wind farm near Limassol, which belongs to AEOLIKI AKTI LTD, is in the final licensing stage.

Cyprus

Six wind farms are in operation in Cyprus, while another one is in the final stage of licensing. In 2019 the total installed capacity was 157,5 MW. Wind energy is the second most important renewable energy technology after solar photovoltaics in Cyprus energy scenarios, scheduled to contribute between 5% and 9% by 2030.

Figure 11.10 **Onshore wind energy capacity in Cyprus from 2010 to 2019 (in megawatts)**



Source: Statista 2020

The development of wind energy in Cyprus has been slow but consistent over the past 10 years and wind farms cover a substantial part of the island's electricity needs. The Orites wind farm is the largest in Cyprus, with an installed capacity of 82MW. Orites, which has been in operation since 2010, comprises 41 wind turbines and produces around 5% of Cyprus' electricity generation capacity. A year later, in August 2011, Rokas Aeoliki (Cyprus) LTD, put into operation the 20MW Agia Anna Wind Farm

Greece

Wind energy output soared to new record highs in Greece in 2019, according to the latest official data released early in 2020 by the Hellenic Wind Energy Association HWEA/ ELEATEN. More new wind energy farms went into operation in 2019 than in any other year in history. This increase represented almost four times the annual average rate of wind power installations during the previous decade, raising the total installed wind capacity to 4,000 MW, and covering 12% of the electricity demand of Greece that year. Greece's National Energy and Climate Plan, envisages 7 GW of wind energy by 2030. The HWEA said the new wind energy farms which began operation in 2019 had a total power of 727.5 MW, four times more than the annual average rate of the previous decade, which was 185 MW. The biggest single wind energy farm operating in the south part of Euboea island has a 154.1 MW installed capacity. Greece's Public Power Corporation (PPC), which has an ambitious wind expansion plan completed a reorganization of its first seven wind energy farms with a significant reduction in the number of wind turbines, from 62 to 15.

Wind turbines in the West Macedonia region of Kozani have the largest rotor diameter of any in the nation, at 136 meters, while the first hybrid electric power station began operation using wind energy and electricity storage in batteries on Tilos island in 2019. Another such hybrid station began pilot operation on Greece's Ikaria island during the same period.

11

The 4GW in installed wind capacity at the end of 2020, represented an impressive 20 percent increase compared to 2019. Foreign investors owned 43% of wind capacity in Greece and accounted for 47% of new investments. Central Greece once again led the nation regarding the amount of wind-powered electricity it produced, followed by the Peloponnese, East Macedonia and Thrace.

Map 11.1 **Spatial distribution of wind capacity in Greece**

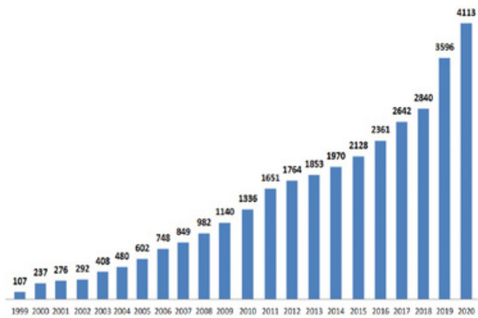
Source: ELETAEN

Terna Energy leads the way with 554.1 MW (18.3%) of the total installed wind energy capacity. The second-largest company by wind energy capacity in Greece is Ellaktor (292 MW or 9.7%), followed by Iberdrola Rokas (250.7 MW or 8.3%), Eren Groupe (242.7 MW or 8%), EDF EN Hellas (238.2 MW or 7.9%), and Enel Green Power (200.5 MW). The next on the list is Mytilineos Group (168.8 MW), ahead of CF Ventus (123.4 MW), PPC Renewables (78.5 MW), ENTEKA (67 MW), Eunice (60.6 MW), and Elsewedy (60.4 MW). All other companies have an individual installed capacity of fewer than 60 MW and a combined capacity of 685.8 MW.

Of the new 198 MW in the first half of 2019, Enercon supplied turbines for 83.8 MW, followed by Siemens Gamesa Renewable Energy (SGRE), with 57.2%, General Electric's (GE) subsidiary GE Renewable Energy, with 38.4 MW, Vestas, with 16 MW, and EWT, with 2.6 MW.

With an overall installed capacity of 1,499.3 MW, Vestas has the largest market share in Greece, of 49.6%, ahead of Enercon, with 701.9 MW, or 23.2%, SGRE, with 595.9 MW, or 19.7%, Nordex, with 150.1 MW, or 5%, GE Renewable Energy, with 38.4 MW, or 1.3%, and others, with a total of 37 MW, or 1.2%.

Figure 11.11 **Wind energy installed capacity in Greece**



Source: ELETAEN

In January 2021, the Greek Wind Energy Association ELETAEN prepared a draft for a mock auction for 300 MW of offshore wind capacity as part of an effort to kick start the sector. According to ELETAEN an official inaugural offshore procurement round could be issued in the first half of 2022.

Kosovo

The first wind installation was put into operation in 2010 near Golesh with a capacity of 1.36 MW. This location is well known for its excellent distribution of wind speeds, but no measurements or research have been provided so far. In 2018, the second wind farm, called Kitka, started operation. With an installed capacity of 32.42 MW it is located in the Kamenica Region. Kosovo is set to more than double its installed renewable energy capacity, with the construction of a 105MW wind farm in Bajgora. The project obtained the go-ahead following the award of a loan for €58 million from the European Bank for

Reconstruction and Development (EBRD). The loan will cover approximately half of the construction cost, with private investors covering the rest. Currently, as much as 90% of Kosovo's electricity comes from two ageing coal-fired power plants, which are said to be among the heaviest polluters in Europe. When complete, Bajgora will represent about 10% of the country's installed capacity and will help avoid 247,000 tonnes of CO_2 a year, making a significant contribution to climate change mitigation. The Bajgora wind farm will contribute towards Kosovo's stated goal of achieving 400MW of renewable capacity by 2026 – with hydro-electric and solar power projects also anticipated. Kosovo declared the Bajgora wind farm a strategic investment last year. The government is targeting a 25% share of wind energy in electricity production by 2026. Also, Bondcom Energy Point is developing the Budakova wind farm project with 46 MW of wind capacity.

Montenegro

Montenegro has two wind farms (2020) in operation with a total capacity of 118 MW, while another two wind farms are in the planning phase with a combined installed capacity of about 130 MW.

The Krnovo project was the first wind farm to be developed in Montenegro. With an installed capacity of 72 MW it is one of the biggest in this part of South East Europe. On an annual basis it supplies power equivalent to 45,863 households while the CO_2 emission reductions are 78,768 tons per annum. The Možura wind farm, Montenegro's second largest, with an installed capacity of 46 MW, has now been officially inaugurated. The Možura wind farm was built by a consortium of Maltese state-owned power utility Enemalta and China's Shanghai Electric Power Company. The state has pledged to guarantee a fixed electricity price of EUR 95.99/MWh and EUR 115 million in incentives over the first 12 years of operation. The wind farm has 23 turbines, which produce 112 GWh of electricity annually. In September 2019 shareholders of the EPCG, the national power company of Montenegro, approved an investment for the construction of the 54.6 MW Gvozd wind farm in partnership with Austria's Ivicom Holding. It is estimated at EUR 58 million. According to EPCG, negotiations on financing the project with the EBRD were at an advanced stage. The tendering procedure for the purchase of the equipment and works will be conducted in accordance with EBRD rules. Construction was to start in 2021. The Gvozd wind farm will have 13 wind turbines and produce about 150 GWh per year. A public call for the construction of another wind farm in Brajici with an installed capacity of more than 70 megawatts is expected to be announced soon.

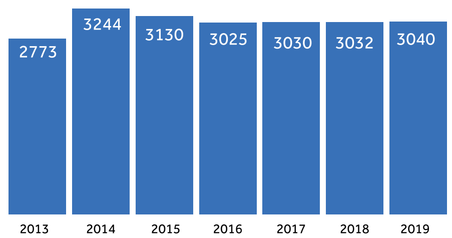
North Macedonia

North Macedonia's first and only wind farm at Bogdanci, has been operating since 2015. The second phase will add four more wind turbines, with a combined capacity of 13.8 MW, as this will increase the total capacity to 50 MW. The new investment is estimated at EUR 21 million. North Macedonia was the first country in the Western Balkan region to put into operation a sizeable wind facility. There are also two more wind farms under construction with most of their permitting process completed, and should bring total installed wind capacity to around 86 MW.

Romania

Wind energy production has been growing fast in Romania over the past decade. Romania's wind energy sector is the second-largest source of renewable energy after hydropower. Wind energy provided about 12% of Romania's electricity in 2018. Installed capacity was 3,040 MW in 2019. The share of wind and other renewables in Romania's electricity generation mix is expected to rise to 35% by 2030. Indicative of the country's lead in wind energy are plans by Nero Renewables to install 237 wind turbines in 3 different sites in South-East Romania by 2021, with a total capacity of approximately 1,000 MW, generating up to 3 TWh per annum. The largest single onshore wind farm in Europe is in Dobrogea, in the region of Fântânele and Cogealac, having an installed capacity of 600 MW. Romania's wind potential is considered to be one of the highest in Southeast Europe with the Dobrogea region being the second-highest wind potential area in the continent. The Romania wind energy market is expected to grow by more than 2.5% annually during the forecast period 2020-2025. The market is expected to witness significant demographic and economic growth, leading to an increase in energy demand. Factors like increasing demand for renewable energy, rising investments in wind farms, efforts to reduce reliance on fossil fuel-based power generation, government policies and declining cost of wind energy are driving the country's wind energy market.

Figure 11.12 **Wind energy installed capacity in Romania, 2013-2019 (MW)**



Source: IRENA, 2020

State-controlled company Hidroelectrica, the largest electricity producer in Romania, has included onshore and offshore wind projects in its investment strategy with a combined capacity of 600 MW and estimated to cost RON 4.8 billion (nearly €1 billion). The two wind farms are part of the company's list of investment projects to be completed by 2027, which require total funds of RON 26 billion (€5.4 billion). The investments planned by 2025 total RON 7.6 billion (€1.5 billion).

Hidroelectrica's planned offshore wind farm, located in North East of Dobrogea Region, will have an installed capacity of 300 MW and require investments of RON 2.88 billion (€594 million) to come from its own sources and European funds (under the Green Deal). This project is estimated to produce 998.6 GWh per year, with an average utilisation capacity of 38%. Hidroelectrica expects to complete the project by 2026. This offshore wind project is based on a study on the potential of wind energy production in the Romanian section of the Black Sea. The onshore section of this wind farm, will add a further 300 MW of capacity and, would cost RON 1.87 billion (€385 million) and will produce 683 GWh per year, at an average capacity factor of 26%. The project should be ready by 2025.

Serbia

The greatest potential of wind energy in Serbia is to be found in the area of Koshava, in South Banat and East Serbia, then in the eastern side of Kopaonik, Zlatibor, Pester in mountain passes at altitudes above 800m, as well as in the valleys of the Danube, Sava and Morava.

The first wind farm was built in 2014 (500 KW). During 2016, two more wind farms were put into operation with a total capacity of 16.5 MW and since 2017 five new wind farms came on stream with total installed capacity of more than 400 MW. From those, the largest is the 57-turbine Čibuk 1, which officially started operation in October 2019 following a €300 million investment. This wind farm has an installed capacity of 158 MW and provides electricity to 113,000 households while displacing 370,000 tonnes of CO_2 emissions per year. Since 2014, wind plants with a total installed capacity of 481.5 MW have been built and two more wind farms that are under construction (2021) will bring the total close to 600 MW.

A proposed Master Plan was presented in 2019 for the construction of a wind farm in the south-eastern part of the administrative area of the city of Subotica between the villages of Cantavir, Višnjevac, Gabric, Bikovo, Stari and Novi Žednik. The location of this wind farm would be at least 1,000 meters from the populated areas. The area would cover an area of approximately 10,800 hectares, equivalent to the area of 15,000 football fields. The value of the wind farm to be built near Cantavir is estimated at €700 million and will have an installed capacity of 600 MW.

Furthermore, the Serbian renewable energy management consultancy firm New Energy Solutions announced in 2020 that it plans to build a 220 MW wind farm in Kovacica, according to a document posted on the website of Kovacica municipality. The wind farm will consist of 31 turbines with a capacity of 7 MW each plus a power substation, as the detailed regulation plan of the project showed.

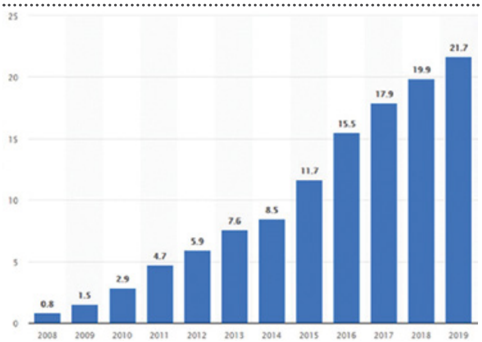
Turkey

Turkey is considered as one of the most important and most dynamic wind markets in SE Europe. In 2019 Turkey added 687 MW of installed wind capacity, which is an increase of 9.32% compared to 2018. In percentage terms, this is the second-worst achievement since 2006, but in terms of installed capacity, only four years have seen better results.

According to the Turkish Wind Energy Statistics Report, the overall installed capacity of 198 wind farms in Turkey reached 8,832 MW at the end of 2020. Turkey has been ranked as the fifth biggest wind power investor in Europe in 2020 with expenditures of €1.6 billion according to WindEurope's Report (April 2021). The average share of wind farms in electricity generation in Turkey was 7.42% in 2019.

Turkey's wind generation was the highest in August – 10.01%, and the lowest in May – 4.91%. In 2020 Turkey had 25 wind power forms under construction with a total installed capacity of 1,309 MW. Turkey's installed wind capacity is forecast to reach 10,000 MW by the end of 2021. The overall wind potential of Turkey is estimated at 48,000 MW.

Figure 11.13 **Wind energy generation in Turkey from 2008 to 2019 (in terawatt-hours)**



Source: Statista, 2020

According to latest data (Turkish Wind Energy Association's (TUREB) report, 2020), wind energy provided about 8 million Turkish homes with electricity in 2019. More than 75% of wind farms are located in the Aegean and Marmara regions of Turkey and only 12.3% of wind farms are located in the Mediterranean region in the South West part of the country. The remaining are located in different locations inland. The Izmir province in the Aegean region saw the most installed wind power capacity with 1,549 MW, while Balikesir ranked second with 1,363 MW and Manisa in Western Turkey followed in third place with 689,9 MW.

11.2.3 Photovoltaics (PV)

During the period 2008–2018, most of the market growth has been driven by incentives and the largest share of cumulative installed solar photovoltaic capacity in some of the South East Europe countries was realised by large-scale, ground-mounted solar power plants. Cumulative installed solar PV capacity in the SEE region saw a 23 per cent increase in 2018 compared to 2017, according to Renewable Market Watch (23). Following the retroactive taxes imposed on photovoltaic investors in Bulgaria, Romania, Slovakia and Greece in 2012-2013 it many developers turned their attention to rooftop residential (up to 30 KW) and commercial (from 100 KW to 1 MW) photovoltaic installations. The increasing cost of electricity and fossil fuels, and the unpredictability of these costs, are expected to drive the rooftop market, corporate renewables market and utility-scale projects under auction (tender) to play an increasing role in solar photovoltaic market development in the CEE & SEE countries by 2030 and beyond. After many years of unfettered growth and innovation, the solar photovoltaic industry in Europe is now going through a challenging period, with shifting market dynamics, growing political support and end of the feed-in tariff support for solar PV installations with above 100 KW power capacity in many countries.

Most of the countries in SEE Europe already possess solid foundations to attract large-scale investments in solar photovoltaic power, but more needs to be done to ensure a successful energy transition, such as strengthening enabling policies as well as regulatory and institutional conditions, and providing strong support schemes for renewables. For this reason, SEE countries present a very good alternative for investors from the already mature and developed solar photovoltaic markets in Western Europe, and for investors from Asia, who are looking aggressively to secure stakes in new photovoltaic markets.

The solar photovoltaic power market in the SEE region has excellent growth prospects in 2020-2030 period. However, strong political will is still needed to build investor confidence, remove bottlenecks and maintain a reliable but dynamic framework for the remuneration of solar photovoltaic energy. But even under the most pessimistic scenario, solar photovoltaic energy will continue to increase its share in the energy mix in the region, becoming a reliable source of clean, safe and abundant renewable energy.[7]

Albania

Although Albania enjoys excellent solar radiation, there is high-untapped potential for the deployment of solar PV, estimated at 1.9 GW. According to the latest statistics published by the International Renewable Energy Agency in 2019, Albania had installed just 1 MW of solar by the end of 2018 and in the first half of 2019, three small solar parks with a capacity of up to 2 MW were grid-connected.

In May 2020, French solar company Voltalia won the tender for the construction of a 140 MW solar power plant in the Karavasta area, in the centre of the country thanks to a bid of €0.02489/kWh. The solar park will be built on 122ha area in the Divjaka municipality, in Remas, and on a further 76ha plot in the Fier municipality of Libofsha. The procurement exercise is the second tender for large-scale solar in Albania.

A previous auction, for a 100 MW solar park, was won by India Power in November 2018. Half of that project was awarded a 15-year tariff of €0.0599/kWh with the balance sold in the retail electricity market. In 2020 Norway's Statkraft started work on a 2 MW floating PV project, first announced in January 2019, at the Banja hydropower reservoir in Albania. It is developing the €2 million plant in partnership with Norwegian floating PV specialist Ocean Sun. The project is being built in a reservoir linked to the 72 MW Banja hydropower plant. The first 500 kW phase is already finalised, while the second 1.5 MW stage was to be completed in 2021. The plant will most likely sell power to the grid under a regulated tariff. PV projects up to 2 MW in size capacity are eligible for a feed-in tariff under Albanian regulations.

In June 2019 Albania's Ministry of Energy and Industry announced the final approval of its net metering scheme for renewable energy. Now in force, the programme is expected to drive the installation of around 200 MW of rooftop PV capacity based on systems with a generation capacity of up to 500 kW each. Eligible projects will be entitled to net metering tariffs equal to electricity market prices with surplus power calculated by utility OSHEE on a monthly basis and final payments at the end of each year. Over the last two years Albania's PV push has focused on large-scale projects but so far no significant deployment of PV installed capacity has resulted.

Bosnia-Herzegovina

As of 2018 the country had around 20 MW of installed solar capacity. The government of the Republic of Srpska intends to change the law on concessions and ease the regulations for installing solar photovoltaic (PV) facilities on land by households and companies. The government has recently adopted a bill to amend the Law on Concessions in a move to ease its interpretation and implementation. In addition to the already defined exemptions, small ground-mounted PV power plants, with an installed capacity of up to 250 kW, cannot be subject to concession procedure. According to the government's website, it was the most significant change in the package compared with the draft and a result of the parliamentary debate.

In January 2020, Bosnian state-owned power utility Elektroprivreda Republike Srpske (ERS)

[7] Renewable Market Watch, "Europe Solar Photovoltaic (PV) Power Market Outlook 2021÷2030", Report, November 2019

announced plans to build a solar plant in Republika Srpska, one of the two administrative entities of Bosnia-Herzegovina. In October 2020 ERS, said it signed a 50-year concession contract with the entity's energy ministry for the construction and operation of a 72.9 MW solar power plant in Trebinje. According to ERS, the Trebinje 1 photovoltaic (PV) plant, worth 100.75 million marka ($60.7 million/€51.5 million), is expected to produce some 100 GWh of electricity per year. The power plant will spread over an area of 120 hectares and should be commissioned in 2022.The solar array will be built near Trebinje, where ERS is based.

European energy trading and investment company Energy Financing Team (EFT) has been declared as the winner of a 60 MW solar power plant in Bileća region in Bosnia. The project is scheduled to enter commercial operations in 2023 with a potential to generate 84 GWh annually, all of which will be sold in the open market. With this auction win, EFT will build and operate the facility for 50 years. The project is estimated to cost BAM 85 million ($47.7 million). The 60 MW project is part of the Serb Republic's 1 GW renewable energy target to be achieved by 2029 and reduce coal power consumption that currently makes up more than 60% of its power generation capacity. The 60 MW PV project will help it consolidate its position in the region.

Bulgaria

Bulgaria had 1,065 MW of solar generation capacity at the end of 2019, according to the International Renewable Energy Agency. In the past seven years, however, lack of incentives has seen only 53 MW of new solar PV added.

The Bulgarian government is planning to re-introduce feed-in tariff payments for rooftop PV for a year, in a move which could revive the nation's solar sector after years of limited growth. The 12-month scheme, yet to be adopted by the energy and water regulator, came into force in July 2020 and expires at the end of June 2021. Under the draft plan, a tariff of BGN238.07/MWh (€121.72) would be applied to rooftop PV installations not exceeding 5 kW in size, and payments of BGN198.27 would be set for 5-30 kW systems.

The growth trends for the solar energy sector are linked to solar PV panels, which constitute a fundamental part of the Bulgarian electricity market. The anticipated power generation from solar PV in the coming years is expected to range from 1,286 to 1,415 GWh per year with the installed capacity to enable her reach approximately 1,320 MW by 2030. Bulgaria has introduced a number of measures to enable it reach the targets for 2030. Some of them are listed below, and describe some possible ways in which Bulgaria could focus its investments in solar PV:

- One of the new directives regulates the introduction of economic support for all those users who have a plant of renewable energy production or a demonstration project of a plant with the same sources, with a power less than or equal to 10.8 kW
- introduction of systems with a total installed capacity of 30 kW and which are planned to be built on structures such as roofs and walls of buildings
- In the period 2021-2030, opportunities will be sought for the financing of renewables projects and measures will be considered to guarantee access to consumption of electricity from renewable sources for low-income consumers

In August 2020, the Municipal Council of Haskovo issued preliminary approval for the construction of a giant solar photovoltaic (PV) power plant with 400 MWp capacity near the villages of Knizhovnik and Dolno Voyvodino located in te Haskovo District of South Bulgaria. The investor who will build the plant is Energy BG 1 which is a project company of the Austrian holding Enery Development GmbH. The photovoltaic power plant expected to generate 560000 MWh and save 650000 tons of carbon dioxide emissions per year according to the company. Furthermore, it will create over 50 permanent jobs and additional jobs during the construction phase of the project that will take up to 12 months.

Croatia

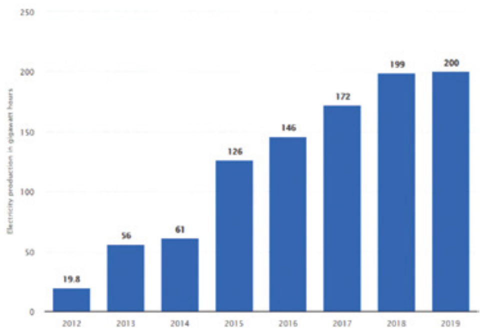
According to the International Renewable Energy Agency, Croatia had a total installed PV capacity of just 69 MW by the end of 2019, with only 1 MW of new annual additions. Most of its installed capacity is represented by residential and commercial PV projects. Such installations were built under the country's expired 50 MW feed-in tariff scheme or under its net-metering regime, which has been in force since January 2019. State-owned utility Hrvatska elektroprivreda (HEP Group) unveiled a plan last year to increase its solar portfolio. The company said the plan would initially lead to the construction of four PV plants with a combined capacity of 11.6 MW on several islands in the Adriatic at a cost of around HRK80 million ($11.5 million).

In May 2020, the government introduced a new tender scheme for renewable energy and co-generation projects, with plans to allocate around 1,075 MW of PV capacity. Overall, the government aims to assign 2.26 GW of renewable energy capacity under the scheme, while also including other sources such as hydropower, wind, biomass, biogas, and geothermal energy. For solar, the government has decided to allocate 210 MW for projects ranging in size from 50 kW to 500 kW; another 210 MW for installations with capacities between 500 kW and 10 MW; and 625 MW for PV power plants exceeding 10 MW. Projects selected under the scheme will be awarded a feed-in price premium, which will be paid for from the power the projects will generate, on top of spot market prices. Solar PV capacity is expected to reach 280 megawatt (MW) in 2030 from 61 MW in 2018 increasing at a compound annual growth rate (CAGR) of 15%.

Cyprus

The use of solar photovoltaics in Cyprus is a success story. Cyprus' electricity generation from solar photovoltaics amounted to 200 GWh in 2019. Between 2012 and 2019, production levels saw steady growth. In the same year, the country recorded a solar photovoltaic cumulative capacity of 128.7 megawatts. Insolation in Cyprus is one of the highest in Europe with more than 320 sunny days a year. Meteorological measurements showed that the annual solar irradiation is approximately 2,002 kWh/m² with a standard deviation of 32 kWh/m². According to the Photovoltaic Geographical Information System (PVGIS), measurements taken from crystalline PV systems with inverter efficiency 96%, showed an average annual yield of 1,672 kWh/kWp (kilowatt hours during peak capacity). The rapid decline in solar PV technology costs, the efficiency increase on PV modules available for the residential sector and EU-supported public policies have substantially increased the number of consumers that have decided to start producing energy under net metering and self-consumption solar support schemes in Cyprus.

Figure 11.14 **Annual volume of electricity produced from solar photovoltaic in Cyprus from 2012 to 2019 (in gigawatt hours)**



Source: Statista, 2020

Today, Cyprus has one of the most developed solar PV markets in Europe regarding net metering and self-consumption due to its geographic location combined with proper government support. Cyprus first introduced a net metering support scheme for residential solar photovoltaic (PV) systems in 2013. After that the government decided in 2015 to plan the country's economic growth by developing renewable energies, and solar photovoltaics in particular. The first step of the strategy was to provide state funding for 2,000 residential solar PV installations to low income households. The Electricity Authority of Cyprus (EAC), started to accept applications on August 22, 2016, for the new scheme of Net Metering "Solar Energy for All" until reaching the set limit of 20MW total power. Cumulative installed solar PV capacity in Cyprus increased more than fivefold between 2012 and 2017.

The country's main strategy to meet the growing need for power is to reduce its energy dependence by improving energy efficiency and aiming for increased use of renewable resources and especially solar photovoltaic energy. According to calculations by the end of 2020 or early in 2021, (source: Renewable Market WatchTM)[8] Cyprus could have up to 93,700 residential and up to 2,860 commercial solar PV installations under net-metering and self-consumption support schemes.

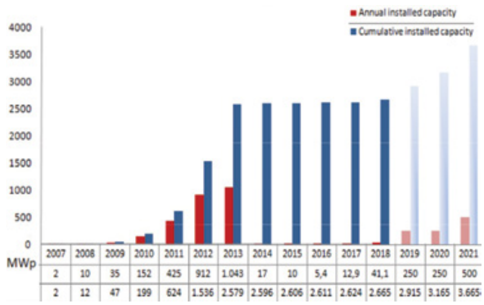
However, limitations of the current power system prevent the higher penetration at the residential and commercial sectors, but in the near future, with the development and use of storage systems, further expansion could be feasible. In February 2018, German company Autarsys GmbH delivered and commissioned the first community energy storage system in Cyprus[9]. It is a pilot project on how to scale up grid-connected renewable energy on the island.

Greece

Greece's new national energy plan mandates 7.7 GW of cumulative solar PV capacity by 2030, up from approximately 3 GW of installed capacity at present with 8,7% share in the total electricity production. Specifically, the plan calls for the nation's total installed PV capacity to increase from 3 GW in 2020 to 3.9 GW in 2022, 5.3 GW in 2025, and 6.3 GW in 2027. The vast majority of the new PV capacity will be large-scale, ground-mounted systems awarded via auctions and supported by premium tariffs.

During the last decade, Greece managed to install 2.6 GWp of PV with feed-in-tariffs, investing €5 billion amidst an unprecedented economic crisis. As a result, 7% of electricity demand in Greece is covered by PV, bringing Greece to third place worldwide, with respect to PV contribution to electricity needs. Greece also ranks 5th world wide with regard to installed PV capacity per capita.

Figure 11.15 **Greek PV market development**



MWp	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	2	10	35	152	425	912	1.043	17	10	5,4	12,9	41,1	250	250	500
	2	12	47	199	624	1.536	2.579	2.596	2.606	2.611	2.624	2.665	2.915	3.165	3.665

Source: helapco.gr, Greek PV Market Investment opportunities

A new support scheme for renewable energy, consistent with the guidelines on state aid for environmental protection and energy 2014-2020 (and based on competitive tenders and feed in premiums), was introduced in 2016. In 2019, a new feed-in tariff scheme was introduced for medium-sized projects that mainly attracted domestic investors. This latest opening to the market has effectively created a second cycle of interest for the Greek PV market. According to a new environmental law (4685/2020) introduced in 2020, as part of a strategic shift in the country's development program, PV plants with a generation capacity of up to 1 MW will be allowed without an environmental license. PV plants bigger than 1 MW must apply for 15-year environmental permits which must be granted within four-and-a-half months.

Since 2019, all new operating PV power plants must have reached agreements with an aggregator, who in turn participates in the Energy Exchange (EnEx) on behalf of producers. While producers have the right to represent their own projects directly on the Energy Exchange, this doesn't make commercial sense unless producers have a critical mass of power plants (e.g. 50 MW or more). Through the participation of aggregators, the market will become increasingly open and liberalised, pushing down production costs and consumer prices.

[8] Renewable Market Watch, "Europe Solar Photovoltaic (PV) Power Market Outlook 2021÷2030", Report, November 2019
[9] https://www.pv-magazine.com/ February 27, 2018

In February 2020, Greek national electric utility Public Power Corp. (PPC) announced that it will fund two large solar parks to be located on mining sites in line with the nation's plan to phase out coal. PPC's goal is to install a massive 2 GW solar project in the Ptolemaida and Kozani regions in northern Greece and a 1 GW installation in the Peloponnese. Construction at Ptolemaida could start as early as 2021. The move is part of Greece's efforts to phase out coal from its electricity mix by 2028. The 2 GW photovoltaic park is also part of the government's plan to create new jobs in the region as it transitions to a coal-free future environment by the end of the decade.

Montenegro

Montenegro has so far made little use of its solar potential, but in 2018 a tender for a 200 MW solar farm was completed. Due to its favorable geographical position Montenegro enjoys abundant solar radiation. Areas with highest insolation are located in the south (near the cities of Bar and Ulcinj) and the area around the capital, Podgorica. There is also a growing interest for the rental of state-owned land to construct ground-installed solar power plants. When an investor expresses such an interest, a public tender for a 30-year rent period must be organised.

The Ministry of Economy has so far issued 19 energy permits for the installation of rooftop PV plants with installed power of up to 1 MW. Their total installed power is around 10,5 MW, while the planned annual production is around 13,8 GWh.

In October 2018, a consortium between Fortum, Montenegrin energy company EPCG and Sterling & Wilson International Solar FZCO won a public tender to build a 200MW solar power plant in the Ulcinj solar site. Montenegro also intended to launch a tendering process for the construction of a solar power plant in Velje brdo near Podgorica. The originally planned capacity of 50 MW could be increased to 150 MW or even 300 MW. The tendering process for the construction of the solar power plant at the Velje brdo site should be announced soon (2021), according to the Ministry of Economy.

With the new law, solar prosumers may get better conditions in Montenegro and the state is also preparing to include PV technology in an energy efficiency program. Households may profit by installing photovoltaic systems on their buildings as the prices are currently favourable. The government says solar prosumers would benefit from the upcoming changes in legislation and solar PV panels would be included in the next energy efficiency programme for homes. EPCG, the power supplier, is obliged to purchase any surplus electricity from owners of photovoltaic units.

Kosovo

As of the end of 2020, Kosovo only had 7 MW of solar PV installed, even though the country has a PV manufacturing plant. In September 2019 Kosovo signed an agreement with the World Bank's International Finance Corporation for advice regarding a proposed 50MW solar PV project. Significantly, the EBRD has also agreed to help Kosovo plan a series of renewables auctions to finance new solar power projects, via an EBRD procurement tender. World Bank data indicate that Kosovo can achieve around a 16% capacity factor for solar, implying around 200 gigawatt hours of electricity generation annually from solar projects.

Kosovo not only has a large technical potential for PV-based renewable energy, but a large portion of it is already economically feasible and it could be realised by 2050. For the 2019-2028 period, Kosovar transmission system operator (KOSTT) plans to add new renewable energy capacities to its transmission network. According to KOSTT's base scenario, there is a potential of at least 85 MW of solar energy, whereas its high scenario identifies a planned capacity of 121 MW to be integrated in the transmission system during the next decade. At a time of falling solar prices, Kosovo has considerable solar potential with an average of 278 sunny days and 2,000 hours of sun per year.

North Macedonia

In February 2020 North Macedonian state-owned electric company Elektrani na Severna Makedonija (ESM) kicked off a tender for 100 MW of solar power generation capacity it wants to deploy at its former Oslomej coal power plant near Kičevo, in the west of the country. The utility is seeking potential partners for the construction of two 50 MW solar parks there through a public-private partnership. The two projects, announced by minister of economy Kreshnik Bekteshi in December 2019, come on top of a 10 MW solar project planned for the same location which the government tendered in April 2019. In 2020 North Macedonia had some 26 MW of solar photovoltaics installed.

Romania

According to the International Renewable Energy Agency, Romania in 2020 installed about 1.38 GW of solar PV plants. Most of this capacity comes from megawatt-scale PV plants built under the country's now-expired green certificate scheme. Green certificates were only granted to companies that connected their PV projects to the grid before January 31, 2016.

In June 2020, Romania's Environment Fund Administration (AFM), the state funding body for environmental protection, in an effort to support residential solar installations under the country's net metering regime, approved 12,718 subsidy applications for the Casa Verde Fotovoltaice (Green PV home) scheme. A total of RON252 million ($59 million) will be paid as rebates in the closed first round of the programme. The total budget for the programme is RON536 million. The Romanian government first launched the rebate scheme in August 2018.

The net metering regulations that were approved in 2020 also include fiscal incentives for owners of PV systems with capacities of up to 27 kW. Under this scheme, owners of renewable energy power systems up to 100 kW in size are entitled to sell power surplus to the country's four power distributors – Enel, CEZ, E. On and Electrica – at a rate that is set by the National Authority for Energy Regulations (ANRE). In March 2020, Romania's Complexul Energetic Oltenia (CE Oltenia) announced its plans to build four PV plants with a combined capacity of 310 MW at one of its coal-powered facilities. The four projects will span 595 hectares, and their capacities will range from 60 MW to 95 MW. The European Commission has already approved the plan. If these big PV projects are actually built, they will mark the revival of large-scale solar energy business in Romania, following several years of stagnation.

Serbia

The number of solar radiation hours in Serbia is between 1,500 and 2,200 hours per year. The average intensity of solar radiation varies from 1.1 kWh/m2/day in the north and to 1.7 kWh/m2/day in the south during January, and from 5.9 to 6.6 kWh/m2/day during July. The average intensity of solar radiation is 1,200 kWh/m2/year in northwest Serbia, 1,550 kWh/m2/year in southeast Serbia, while in the central part is around 1,400 kWh/m2/year. Serbia has a significantly higher number of solar radiation hours than many European countries.

According to the International Renewable Energy Agency, Serbia had installed just 21 MW of PV capacity by the end of 2020. This is probably all the capacity assigned through the expired FIT scheme, which granted rates ranging from €0.124 ($0.15)/kWh to €0.146/kWh for rooftop PV arrays, depending on system size, and €0.09/kWh for ground-mounted installations, all under 12-year power purchase agreements. According to the Serbian government's energy strategy, the nation's cumulative PV capacity is expected to increase to 100 MW by 2025, and 200 MW by 2030.

Serbia provided incentives for the construction of solar power plants through subsidies for the first time by introducing the By-Law on Feed-in Tariffs for the production of energy from renewable energy sources and combined heat and power generation from 2009. Since then, the government has increased the allowed capacity and reduced the feed-in tariff through two new By-Laws in 2013 and 2016.

In September 2019, the then Serbian Minister of Mining and Energy, Aleksandar Antic, said that state-owned power utility EPS is considering the construction of a 100 MW solar power plant (24). Minister Antic further said that EPS is planning to build a small-scale solar power plant of up to 10 MW of installed capacity first, followed by a large-scale project of up to 100 MW in Kostolac. He stressed that EPS needs to invest in renewable energy in order to diversify its production portfolio, thus improving the country's energy mix which is too reliant on coal-based energy. The project for the photovoltaic power plant envisages the construction of a 100 MW solar park at an ash landfill created next to the thermal power plants Kostolac A and Kostolac B, and the project is currently under consideration. The landfill has an area of 270 hectares, while production of solar power plants would total to 97.2 million kWh per year.

Turkey

Turkey reached a cumulative 6,700 MW of installed solar PV capacity in 2020, according to statistics from grid operator TEIAS. Of Turkey's total solar capacity, 6,500 MW represent 'unlicensed' PV systems – installations with a capacity of no more than 1 MW. Licensed projects, awarded through public tenders, correspond to 169.7 MW. Solar makes up approximately 6.5% of Turkey's power generation capacity, which at the end of 2020 stood at 93 GW.

It is estimated that 850-1,150 MW of new solar PV capacity was deployed within 2020. Around 350 MW of this capacity came in the form of unlicensed projects, which received extensions of their grid-connection deadlines. The rest was provided by licensed projects and distributed generation. It is estimated that the Turkish solar PV market will grow by at least 1 GW annually over the next decade.

Market sources agree that rooftop PV will drive the next phase of solar market growth, after new rules for distributed generation were introduced last year. It is expected that provisions for energy storage will be introduced and a 1 GW solar tender planned under the nation's Renewable Energy Resources Area Project will be implemented. In July 2020 Turkey's Ministry of Energy and Natural Resources published details of the 1 GW solar auction. The smallest project allowed under the new tender rales is 10 MW, while the largest is 20 MW.

KRC Consulting and Life Enerji [10]) observe that the 1 GW auction is like the light at the end of the tunnel for the Turkish solar industry, which had been in decline in 2020 even before the effects of Covid-19 were felt. In the first five months of 2020, total installed PV capacity for the year stood at just 157 MW compared to previous year's almost 923 MW for the full year. Even 2019's PV installations marked a decline from the 1.6 GW realised in 2018. Turkey's solar industry has been desperately looking for planning security during Covid-19. Such auctions are more than welcome, since rooftop self-consumption models are apparently not moving forward fast enough.

Additional policy measures to introduce "green tariffs" for electricity consumers may deliver another boost to solar developers – potentially driving demand. Within the framework of reforms in Turkey's electricity market, there has been a need to amend the Regulation on the Renewable Energy Resource Guarantee Certificate in the Electricity Market and the Regulation on the Documentation and Support of Renewable Energy Resources. For this purpose, a draft was published on July 1, 2020, amending the legislation in question. The Draft Regulation was open to public consultation and evaluation until July 28, 2020.

The tariff regulatory reform seeks to introduce an electricity tariff for Turkish consumers based on renewable energy sources. It introduces a legal framework for a "green tariff", allowing electricity consumers the opportunity to purchase certified clean energy. It draws on similar moves in other countries. To introduce such tariffs, new regulations are required. Accordingly, the "Draft of Renewable Energy Resource Guarantee Certificate Regulation in Electricity Market" (REC Regulation) has been prepared. In terms of compliance with this new

[10] PV-Magazine, Green electricity tariffs, 1 GW solar tender 'light at the end of the tunnel' for Turkish PV, 3 July 2020

regulation, some amendments were made in the Regulation on Certification and Support of Renewable Energy Resources.

Meanwhile, Turkey's Ministry of Energy is preparing a "Green Tariff" which will be a new end-user tariff for those seeking to source their electricity from 100% renewable sources. Suppliers of this tariff will be required to issue and retire RECs for each MWh to be sold in accordance with the REC Regulation. Turkey's current feed-in-tariff program (YEKDEM) ended at the end of 2020. It is not certain what shape YEKDEM's replacement will take – although the 1 GW auction provides some certainty. The Green Tariff and RECs appear to be the main instruments to be used by the Ministry in fostering further renewable energy development.

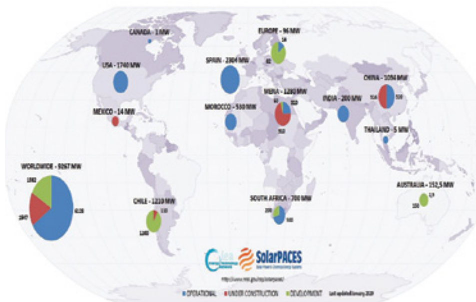
It is clear that the Turkish government is looking to promote demand-side measures. Participation to both Green Tariff and RECs are voluntary as for now, thus public interest in these new instruments is in question. However, the Energy Ministry may impose some REC quotas on electricity suppliers or provide some incentives for the REC users in future – which may be an effective boost for renewable energy investments in Turkey.

A Solar Energy Roadmap published by the Turkish PV Association in October 2020 said the country could install 38 GW of solar by 2030. That conclusion came after a report published by the Shura Energy Transition Center in May 2018, which predicted solar could pass 20 GW by 2026.

11.2.4 Concentrated Solar Power (CSP)

Concentrated Solar Power (CSP) generates electricity by focusing solar heat from hundreds of mirrors or lenses onto a receiver, which then drives a heat engine. According to the German Aerospace Centre (DLR), the potential of electricity produced by Concentrated Solar Power (CSP) in Europe is around 1,500 TWh/year with the Mediterranean countries having the highest potential according to available solar radiation (over 2000 kWh/year) records. Currently, there are over 25 GW of installed CSP capacity worldwide and more than 2,000 MW under development. CSP projects employed 22,000 people worldwide in 2016, 15,000 in the case of Europe. In the period 2015-2030, solar thermal electricity is expected to create up to 150,000 qualified jobs including engineering, development and financing, manufacturing, construction, operation and maintenance.

Map 11.2 **CSP projects around the world in 2018**



Source: SolarPACE

The potential deployment of CSP technology is supported by national policies. Six EU countries have included CSP in their National Renewable Energy Action Plans (NREAPs): Cyprus, France, Greece, Italy, Portugal and Spain. Despite the depressed economic environment during the coronavirus pandemic, CSP technology is expected to spread in the coming years. The introduction of innovative technologies is absolutely necessary in the case of CSP in order to reduce costs. Volumes deployed (learning curve and economies of scale) and risk-financing will also be key to pioneering projects. In addition, extra help will be necessary in terms of incentives for first-of-a-kind demonstration projects and subsequent market deployment, including the ability to supply dispatchable electricity generated by CSP plants from Southern Europe to Central/Northern Europe, thereby facilitating CSP access to new markets. Although CSP does not remain as stable as other renewable technologies, it shows a remarkable growth during last decade with a total installed capacity increasing by 27%. Spain's first CSP plant went into operation in 2008, and it is still the only European country with commercial CSP plants. CSP activity has shifted from Spain and the United States to developing countries since 2015, the Renewable Energy Policy Network for the 21st Century (REN21) noted in its 2017 annual report. Activity has continued in Europe on a pilot scale, including the construction in France of a 9 MW Fresnel facility, and the construction in Denmark of a hybrid biomass-CSP facility incorporating 17 MW of CSP, the REN21 reported noted.

Under IRENA's base-case scenario (25), Europe will have 4 GW of CSP capacity by 2030. But under its REmap study, which analyses what is technically feasible and cost-effective from a social perspective by 2030, that figure could rise to 5 GW.

Cyprus

The Cyprus CSPc EOS Green Energy project has been in the pipeline for several years, with deadlines missed as early as 2016. The designated location is in the south, near Limassol. The CSP system was supposed to be commissioned in June 2020 by Alfa Mediterranean, a property developer, registered in Paphos. The design includes a modular tower system, with high purity graphite heat storage towers and heliostats, feeding a superheated steam cycle. It should have 300 heliostat modules and a single 50 MW turbine, and cover an area of up to 180 hectares. Capital expenditure was estimated at €175 million with funding from the EU corresponding to €60.2 million and annual output projected at 172 GWh.

The EOS project is designed for maximum operating flexibility, with two 25 MW generators, where one is a standby unit. The plant will be able to operate during peak hours or in emergencies, at a capacity of 50 MW. The facility is designed to operate for 24 hours at 25 MW output, but it could just as easily operate at 50 MW for 12 hours. As the heat is stored, the facility can generate electricity to be stored at night as well. Alfa Mediterranean is waiting for a loan from the European Investment Bank to start building the system.

Greece

The M.IN.O.S. (Minimum Intermittency Operating System) Solar Tower Concentrated Power Project on the island of Crete has been on hold due to coronavirus complications. The project involves the construction of a CSP tower solar power plant with the total installed capacity of 50 MW on 160 hectares of land. The CSP central receiver tower technology with a 5-hour molten salt storage is to be applied in this project. In November 2019, following a high-level meeting between the Greek Prime Minister, Kyriakos Mitsotakis and the Chinese President Xi Jinping, a project financing cooperation agreement was signed.

The agreement foresees that the MINOS 50 MW CSP project in Crete will be developed by Nur Energie (see www.nurenergie,com, a UK-based consortium formed by China Gezhouba Group International Engineering Co. Ltd and Zhejiang Supcon Solar Technology Co. Ltd. Greek company PRENETON will be appointed as EPC contractor responsible for the project, and the Commerical Bank of China (ICBC) will provide financing support for the project. The project developer Nur-MOH Heliothermal S.A. is a joint venture of Nur Energie & Motor Oil Hellas. Engineering Services for Energy S.r.l. will join this project as owner's engineer.

The project is the first CSP tower power plant type in Greece and the first "Technology + Equipment + Engineering" mode for China's CSP technology internationally. It is also touted as a demonstration of the "17+1 cooperation", a mechanism between China and Central and Eastern European Countries. Furthermore, the project has been conceived as a high-quality application of Belt and Road policies as well as a typical example of international multilateral friendly cooperation.

The site in Crete is considered to be a prime location for solar energy use as it enjoys some of the highest solar radiation in Europe. Once completed, it can provide high-quality clean electricity equivalent to 10% of the island's electricity demand. While meeting the increasing power demand of the island it also has great environmental significance.

In addition, it is estimated that during the construction period it will provide more than 500 jobs, while it will help create 50 jobs on a long-term basis during its 25-year operation period. Therefore, the promotion of the MINOS 50MW CSP project has received much attention and support from the local government. The Greek government has described it as one of the 'key green projects' and as a "strategic investment".

Turkey

In 2013, the first CSP tower plant was built in Turkey's sunny southern province of Mersin with a 5 MW capacity. Turkish energy company Greenway was responsible for the construction of Turkey's first "concentrating solar power tower plant".

This CSP plant, represents an investment of $50 million by Greenway with the support of Turkey's science agency TÜBİTAK and the Technology Development Foundation of Turkey (TTGV), The plant can cover the electricity requirements of 1,500 houses. A natural circulation direct steam generation boiler is used. After an extensive research and development period, the Greenway CSP Mersin Solar Plant began its operation in March 2013. According to the Greenway Company the plan is to build 10 to 50 megawatt power such plants in the years to follow.

Discussion

The review of CSP activity focused on Greece, Cyprus and Turkey since no other countries in the region have been reported noteworthy projects. This is indicative of the limited attention that such technologies have received so far in this part of the world and the limited interest by prospective investors. A disadvantage of a CSP plant compared with photovoltaics, which appeal to all different classes of investors, is the great amount of land area required and the need to employ professional personnel who will look after their operation. On the positive side is the capability of CSP plants to operate almost on a 24hour basis, as they can employ molten salt heat storage facilities.

In view of the relatively high solar radiation required on an annual basis to operate efficiently CSP plants, the geographical area covered by Greece, Turkey and Cyprus appears the most promising for all different types of CSP plants. As the successful operation of CSP requires full integration into the grid and continuous attention for their operation such projects are best to be undertaken by utilities which can provide the necessary resources and technical back up.

11.2.5 Biomass & Biogas

Biomass and Biogas constitute sectors with high energy potential, both, in South East Europe and in the EU27. They encompass more than half of the renewable energy sources for heat applications, with heat covering more than half of the final energy consumption in Europe, but their use for electricity generation is still considered to be low.

The use of solid biomass fuel for electricity generation has been applied progressively in SEE Europe over the last 20 years. Biomass plants and biomass co-firing plants are actually studied and developed in some of these countries. We consider as solid biomass all agricultural residues, wood flakes or pellets, olive pomace and any plants that can be used as solid biofuels and any organic waste that can be used to produce biogas. Each country in SEE has different biomass type resources which can be tapped for use inside the country or exported nearby.

Forest-based biomass is dominant in Montenegro, Bosnia-Herzegovina, Albania and North Macedonia. On the other hand, agriculture is the main source of biomass in Moldova, Ukraine, Serbia and Croatia. Currently, these countries depend heavily on fossil fuels and imports to cover their energy requirements. However, biomass could supply 10% to 15% of the energy needs in SE Europe countries (26). Electricity generation via either co-firing in existing power plants or Combined Heat Production only plants is a realistic option for future investment in the SEE region. As far as power generation is concerned, local, domestic use of agricultural residues and organic waste is an important sector in all counties and high-efficiency, low-emissions power plants could be used for power generation.

The West Balkan region uses eight million hectares (ha) of agricultural land, while nearly another million ha is abandoned, representing a massive potential for biomass production or other land uses, without putting pressure on food production (27). Serbia alone could annually produce biomass of 1.7 Mtoe – which is almost equal to Croatia's entire annual natural gas consumption, while Bosnia-Herzegovina could produce 0.31 Mtoe. Wheat and corn are the two most cultivated crops in the region and thus have the most immediate potential for biomass production from residues. It has been estimated that Croatia could produce 0.17 Mtoe just from the residues of wheat straw and 0.20 Mtoe from corn stovers. In addition to use of agricultural residues, Perakis et al. (2010) have estimated that the SEE region could potentially generate 157 MW from installed biogas power plants (operating at 8,000 hours per year this would result in 0.11 Mtoe of energy per year).

Albania

The country has a significant potential for renewable resources in the form of biomass. Forestry zones cover around 36% of the total the country's surface. The total reserves of fuel wood in Albania are estimated at approximately 6 Mtoe. The energy potential from agricultural residues was calculated at around 43,000 GW and the energy potential from animal residues as well as potation from agricultural waste is calculated at approximately 70 toe/year with an increasing trend. The ubiquitous farmlands obviously have access to tremendous quantities of biomass. The potential of urban wastes from the main Albanian cities was calculated as approximately 405,615 Toe, a number which is likely to increase in future.

As of 2020, however, Albania was not producing any biofuels, biomass or biogas.

Bosnia-Herzegovina

The current biomass co-generation using by-products of the wood-processing industry in Bosnia-Herzegovina is around 26 MWel. Several projects are currently under development. However, awareness-raising and other promotion measures despite the FIT and available technology quotas are required to exploit the full potential. Currently a new biomass-fired cogeneration (CHP) plant "Nova Toplana" Prijedor (with installed capacity of 0.250 MWe and 20 MWt), and one biogas power plant "Buffalo Energy GOLD-MG", Novo Selo, in the municipality of Šamac, (installed capacity 0.999 MWe) were built and connected to the grid. Two new CHP biomass plants at "Nova Topola" in the municipality of Gradiska (installed capacity 0.992 MWe and 4.8 MWt), and "Cogeneration plant on biomass", in Kneževo municipality (installed capacity 0.820 MWe and 5 MWt) are under construction (2020).

Action plans define the quotas for solid biomass and biogas, but incentives for biogas have not yet been included. Not a single biogas project has yet been put into operation. The duration of feed-in tariffs is 12 years for all technologies, although practice has shown that for some technologies, such as for biomass plants, the repayment period of the investment exceeds 12 years.

With regard to biogas, the largest available potential for Bosnia-Herzegovina comes from farm animal waste, with a total unused potential of around 2.3 MWel[11] from cattle, pig and poultry manure. The recent introduction of the quota for biogas and the respective adaptation of the related FIT targets that potential.

Bulgaria

The electricity generation capacity from biomass in Bulgaria is estimated at 78MW. On May 2020, the Bulgarian Energy and Water Regulatory Commission (EWRC) published its draft decision on the preferential prices for electricity from Renewable Energy Sources (RES). It included updated preferential prices

[11] Energy Community, Bosnia & Herzegovina, Annual Implementation Report, November 2020

for electricity from biomass and the premium price to be paid for RES power plants with total installed capacity of 1 MW and above. According to the decision, the new price for Biomass with installed capacity of up to 5 MW is BGN 295.30/MWh ($178.65/MWh). According to the Electricity System Operator (ESO) and its plan for the development of the country's power distribution network, Biomass plants will add a combined 64 MW to the grid by 2025. Bulgaria has also 20 MW installed capacity from Biogas.

A subsidiary of China's environmental protection solutions company Sunpower Group announced in 2019 that it will design a biomass power generation facility. The subsidiary, Shandong Yangguang Engineering Design Institute Co. Ltd. will design the facility with a power generation capacity of 16 MW, using waste from the pulp production process as the main fuel.

Croatia

Since January 2016, the Croatian support system for renewables changed from a feed-in-tariff system to a market premium system through the Law on Renewable Energy Sources and High Efficient Cogeneration. The implementing regulations are pending. The change of the supporting system has accelerated quota bookings with projects under development in late 2016. In the bioenergy sector, the solid biomass quota has been exploited (120 MWe) up to a point, but some of the contracted projects are failing to keep up with the implementation deadlines.
As a consequence, the contracted projects are losing their agreed quota share. In 2019 there were 17 biomass power plants (35.95 MW), 31 biogas power plants (35.72 MW), two power plants on landfill and wastewater gas (5.5 MW) and five cogeneration plants with a total installed capacity of 113.29 MW. In 2019, there was 5.6 MWe and ~9 MWe space available for solid biomass and biogas projects. All projects that have earned quota rights by 2016 are eligible for the FiT but those who have failed to fulfill the requirements for implementation are losing both eligibility for the FiT and their quota share.

Cyprus

The share of biomass for electricity production in Cyprus in 2018 was 3,03%. In 2019 there were 14 biomass units in operation with a total installed capacity of 9.7 MWe. According to the Cyprus RES National Plan, the total installed capacity of biomass units expected to reach 17 MWe. The total energy of biomass is generated from manure/organic animal waste and is sold to the country's sole electricity company. In 2017, the Ministry of Energy, Commerce, Industry and Tourism announced a new scheme to install systems which produce electricity from RES for commercial purposes. The goal was to integrate such systems into the competitive electricity market and achieve the national target, in accordance with the Renewable Energy Directive 2009/28/EC. This scheme, which was amended in 2018, promotes the installation of biomass utilisation systems of up to 5 MW each.

Greece

At the end of 2019, the total installed power from 25 active biogas electricity producing plants was 22,76 MWe. For their operation these plants incinerate:

- Residues from agriculture and forestry
- Residues from the food industry
- Cotton and wood processing waste
- Straw from rice cultivation
- Olive pomace and fruit stones

Compared to other renewable energy sectors in Greece, the bioenergy industry shows the biggest growth potential despite the economic slowdown caused by Covid-19. The Greek biogas sector is still in its infancy. As of late 2019, some 37 biogas plants were operating in Greece of which 30 were landfill or sewage gas treatment plants. The largest biogas project in the country is connected to the capital's wastewater treatment plant on the island of Psyttaleia offshore Piraeus and has been in operation since 2004. The sewage water from the metropolitan Athens area is pumped through a 1.5 kilometer pipeline from the mainland to the plant. The technical figures of this plant are enormous. The biological cleaning stage includes twelve digesters with a total volume of 300,000 cubic meters and a daily flow rate of 1,000,000 cubic meters. The biogas from the anaerobic digestion of the sewage sludge is converted into electricity and heat by four gas turbines. The installed electrical capacity is 5.04 MW. Only seven Greek biogas plants run on animal excrement, slaughterhouse wastes or fermentable waste from agriculture or the food industry. Four of them are in northern Greece. Another one is located on the west coast, one close to Athens and one on the island of Crete. The total installed electricity output of all 37 biogas installations is 60 megawatts (2020).

Kosovo

The generation of electricity from biomass is not viewed with interest by investors, even though the installation of 14 MW has been licensed. So far, the only the biomass plant for heating purposes is in the city of Gjakova and has applied for the final authorization for 1.2 MWth. The great lack of interest by investors in this sector is due to the difficult procedures for obtaining licenses and the high cost of installing the necessary technology.

To encourage the use of RES, Kosovo has set up a legal framework as well as a support scheme through feed-in tariffs for hydropower, wind, photovoltaics, and biomass. According to the Kosovo ERO, the electricity produced from biomass can be sold at €71.3/MWh. To fulfil renewables targets, Kosovo institutions have planned to install up to 14 MW of biomass capacities in the power system. Biomass has great potential to fulfil the targets for renewable generated electricity.

These targets are defined by the National Plan of Action for Renewable Energy Sources. It is estimated that Kosovo can produce 105 GWh a year of electricity from biomass.

Table 11.6 **Annual potential amount of electricity, thermal energy, and co-generation from biomass in Kosovo**

Type of Biomass	Electricity		Thermal Energy		Co-Generated Energy			
					Electricity		Thermal	
	(GWh/ year)	(ktoe/ year)	(GWh/ year)	(ktoe/ year)	(GWh/ year)	(ktoe/ year)	(GWh/ year)	(ktoe/ year)
Forestry Biomass	423	36.38	1027	88.35	242	20.79	725	62.36
	1523	131	3699	318.13	870	74.85	2611	224.56
Biomass from cereal	179	15.43	436	37.46	103	8.815	308	26.445
Biomass from fodder	-	-	-	-	28	2.39	21	1.83
Biomass from orchard and vineyards	24	2.05	56	4.97	14	1.17	41	3.51
Biomass from livestock farming	-	-	-	-	430	36.99	330	28.36
Biomass from timber industry and sawmills	22	1.85	52	4.49	12	1.06	37	3.17
Biomass from urban waste	165	14.22	468	40.28	110	9.48	331	28.44
	379	32.6	1074	92.36	239	21.73	758	65.2
Total	813.02	62.92	2041	175.56	938	80.68	1792	154.11

Source: Analysis of the Potential for Renewable Utilization in Kosovo Power Sector, Published: 24 June 2020

Montenegro

Montenegro has no biomass or biogas installed capacity. However, several projects have been proposed. Biogas in Montenegro is recognised as a renewable energy source and thus is an eligible technology for feed-in tariff in the electricity generating sector.

Table 11.7 **Calculation of the feed-in tariffs f or Biomass in Montenegro, as of 01.03.2017**

Type of plant	Scale of the installation	c€/kWh
Biomass	from forestry and agriculture	13.71
	from wood processing industry	12.31
Solid landfill waste		9.00
Gas from landfills		8.00
Biogas		15.00
High efficiency cogeneration	installed capacity up to 1 MWe	10.00
	installed capacity (P) from 1 MWe up to 5 MWe	according to formula: 10.00 – 0.5 x (P-1)
	installed capacity from 5 MWe up to 10 MWe	8.00

Source: Ministry of Economy, Montenegro)

In 2017 the municipal operator of the landfill in Montenegro's capital city Podgorica initiated the construction of the first power plant that will run on biogas from waste. The plan is to tap the gas and lead it to a 1 MW cogeneration facility to generate an optimal output of electricity. In 2018 the Podgorica-based Deponija company invited all interested parties to submit bids at the tender call for granting concessions for exploiting landfill biogas for generating electricity at the Livade landfill in Podgorica. The total investment is €1.92m. In addition, total annual expenditures covering oil, service, maintenance and depreciation costs amount to €284,663, and the total annual revenue from delivered electricity is estimated at €699,200.

North Macedonia

The capacity of existing biogas power plants is 7 MW (2020), while an additional 14 MW are under construction. Biomass has 4,3 MW of installed capacity while an additional 6 plants are in the process of construction. A feed-in tariff is granted to a preferential producer for the generation of electricity from a thermal power plant using biomass and biogas.

Thermo power plants based on biomass (with installed capacity less or equal to 3 MW and percentage share of the fossil fuels lower or equal to 15%) are estimated €5/kWh (art. 10 par. 5 FiT Decree). If the percentage share of fossil fuels in the total energy value of the fuel is 15%–30%, the reduced tariffs are calculated on the basis of a formula (art. 10 par. 6 FiT Decree). Thermo power plants using biogas (with percentage share of the fossil lower or equal to 10%) – are entitled €18.00/kWh (art. 11 par. 4 FiT Decree). If the share of fossil fuels in the total energy value of the fuel is between 10% –20%, the reduced tariffs are calculated according to a formula (art. 11 par. 5 FiT Decree). The maximum installed capacity of renewable energy generators is defined for each technology separately.

Romania

Official statistics indicate that 112 MW of installed capacity from biomass are in operation, which corresponds to 0.5% share of the total electricity installed capacity, while there is also 20,5 MW of installed capacity from biogas (2020 update). Currently, the annual production of energy from renewable resources in Romania is approximately 6,550 ktoe (kilotons of oil equivalent). A technical potential of 8,000 ktoe remains unexploited.
Romania has a huge biomass potential, coming especially from agricultural (60%) and forest (20%) waste. But presently this biomass is used only for heating, which should be no surprise, given that of the almost 8.5 million homes in Romania only one third have access to gas networks. The other two thirds use gas cylinders or wood for heating or cooking. In fact, the poor penetration of gas in Romania's homes should come as a surprise, given that Romania is one of the few European countries that benefit from its own gas resources and has one of the lowest degrees of import dependence. Despite the existence of an attractive support scheme for energy from biogas and wide-ranging tradition in this field, the Romanian biogas sector underwent a slower development than expected. At the end of 2019 only 18 biogas plants with an installed capacity of 20.5 MW fed the Romanian national power grid.

On a more general level, modern farms are a prerequisite for setting up an efficient value chain for biogas, from collecting the crop residues, to the anaerobic digester, to maximising the value of the produced biogas, locally or by selling heat/electricity to the grid. Only pooling the arable land into medium- and large-scale farms or cooperatives and a high degree of mechanisation can make the investment in biogas from crop residues and livestock worthwhile. The ongoing, gradual modernisation of Romanian agriculture, which takes place independently from biogas incentives, will lay the foundation for increased biogas production over the next years. As farmers come into a position to invest in biogas, regional and local authorities should support them with the basic expertise needed to embark on biogas projects.

There is considerable potential for biogas production from landfill waste and wastewater treatment plants. Romania sends most of its waste to landfills, but this should change towards more recycling and incineration. However, considerable potential remains in landfill gas use. Many Romanian municipalities lack modern wastewater treatment facilities, but there is considerable funding from the EU to catch up in this respect. With proper regulation and stable incentives in place, it should be possible to trigger investments in biogas production from both landfill and wastewater treatment plants in most of Romania's municipalities.

This would be a welcome renewable addition to local energy supplies, at the same time improving the environment and combating climate change.

Serbia

Total electricity produced from biomass and biogas in Serbia in 2019 was estimated at 15 MW producing 136 GWh a year, giving it a 10% share in the total installed capacity. It could be said that investments especially in biogas plants have experienced a boom over 2017-2019, following a decision in 2016 to increase the feed-in tariff. This state subsidy ranges from €0.15 to €0.17 per kWh. The state register of privileged and temporary privileged producers of electricity and producers from renewable energy sources includes biogas power plants with an installed capacity of 48 MW. In 2020 alone, the status of a privileged or temporary privileged producer was awarded to 10 MW of power plants.

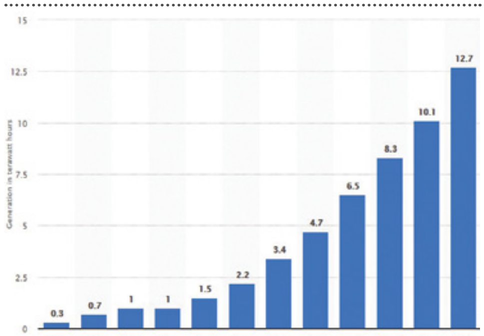
The National Renewable Energy Action Plan envisages the construction of biogas power plants with a combined capacity of 30 MW. There are no quotas for the overall installed capacity of biogas power plants under the feed-in tariff system, such as for wind farms and solar PV plants. At the end of 2018 the government said that the latest renewable energy scheme will not introduce caps on small-scale wind farms, biogas facilities, and small hydropower plants. It is possible, however, as the government said, that there will be changes to feed-in tariffs for biogas facilities. If they gain the status of privileged power producer, investors in biomass, biogas or landfill gas plants in Serbia can count on the incentive purchase price of the produced electricity within a 12-year period, while the investment return period ranges from 7 to 9 years. Despite this incentive, prescribed quotas for biomass and biogas plants until 2020 had not been used.

Turkey

Electricity production from Biomass and Biogas in Turkey corresponds to about 2.6 percent of total demand. Under a scheme introduced in 2011 the support for biomass plants is fixed at $0.133/kWh. The Biomass energy potential in Turkey is high and there are already several projects in line. At the end of 2020, there were 125 biomass-fueled (biogas, thermal, landfill and wastewater) power plants that had received a production license from EMRA; their total installed capacity is 900 MWe. Forty percent of the installed biomass sector in Turkey is related to landfill gas facilities. Incineration and gasification facilities, which are based on thermal biomass technologies, constitute 33%, of the total biomass installed capacity. Energy production through biogas from solid wastes such as animal faeces and agricultural wastes has increased in the last five years. At the end of 2020 the installed capacity was 1,3 GW and is set to increase.

Electricity produced from landfills is a simple process and project development, location selection, waste procurement etc are handled entirely by local municipalities. Proper regulations and practices in recent years have increased the number of biogas plants. Turkey has a high potential in terms of animal waste and agriculture. Turkey is an agricultural country with huge potential and thus the biomass market is one of the most promising renewable sectors. Meanwhile, landfill gas power plants account for almost half of the currently installed biomass capacity. The market being dominated by landfill gas facilities creates a serious investment potential in terms of biogas and thermal biomass power plants.

Figure 11.16 **Geothermal and Biomass-gas energy generation in Turkey from 2008 to 2019 (in terawatt hours**



Source: Statista, 2020

11.2.6 Geothermal Energy

Turkey is an emerging superstar in geothermal energy applications thanks to a combination of its underground resources and a stable tariff regime. Other countries in Southeast Europe lag far behind the kind of investment seen in Turkey, the site of some of the world's largest geothermal power plants, but they too are increasingly harnessing underground energy to provide cheap and eco-friendly local heating and energy.

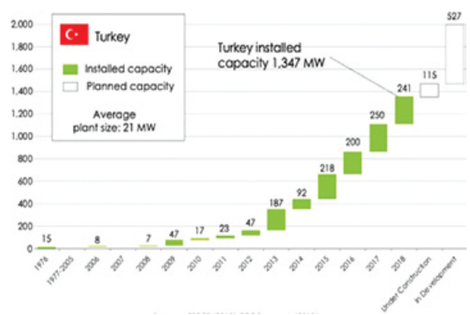
Investment in geothermal energy in Turkey has gathered momentum recently. The country ranked seventh in the world in terms of installed geothermal capacity established at 1,550 MW in 2020 and 4th worldwide (first is the USA, with Indonesia and Philippines following) , according to geoenergy portal ThinkGeoEnergy. This puts it ahead of countries that have long relied on the technology, such as Iceland and Kenya. Turkey represents nearly all new geothermal capacity added globally in 2020. This is largely thanks to its natural resources — exploratory research has shown abundant hot water resources, some with temperatures of more than 200°C.

Besides Turkey, which has the most developed geothermal sector in the region, Greece, Romania, Bulgaria, Slovenia and Croatia are seen as the only countries in of SEE with some relevant geothermal development potential. Binary plants that allow cooler geothermal reservoirs to be used for electricity generation are the only feasible option, which offers a potential of up to 690 megawatts (MW) at an average LCOE of €86/MWh (€0.086/ kWh) in the medium cost of capital scenario. This renewable source could be deployed mainly in Greece, Romania and, to a lesser extent, in Bulgaria, Croatia and Slovenia (28). In the rest of SEE, geothermal electricity potential is often marginal and uncertain. It is estimated that the planned geothermal power development of those countries is in the region of at 20 MW by 2020.

Turkey

Geothermal utilisation in Turkey shows a remarkable increase, especially for electricity production and direct use applications. As far as major applications are concerned, Turkey currently has 55 geothermal power plants and 17 geothermal city heating systems in operation. About 12% of Turkey's geothermal potential is utilised so far for heat and electricity. About 450 geothermal fields have been discovered over the years with the General Directorate of Mineral Research and Exploration having undertaken all research and the lead-in applications. Thanks to the rapid development in capacity, at the end of 2019 this stood at 1,550 MWe, the fourth largest in the world after the United States, Indonesia and the Philippines, while for heating applications it was only second to China.

Figure 11.17 **Geothermal Development in Turkey, Additions by year**



Source: JESDER, 2019 – TGE Research, 2019

It should be pointed out that the installed geothermal electricity capacity has increased twice since 2016. According to the government, Turkey wants to be able to make better use of its geothermal energy potential and aimed to achieve a geothermal-based power generation capacity of 2,000 MW by 2021. Its 2030 target has now been revised upwards to approximtely 4,000 MW. According to the Turkish Association of Geothermal Investors (JESDER), the estimated remaining power generation potential from geothermal sources in the western regions of the country stands at 3,000 MW. Currently, the share of geothermal energy in the total electricity production of the country is just under 2.4 percent.

Deep reservoir exploration is in progress by government agencies and private companies focusing on power generation. For this reason, deep drilling targets have reached up to 4,500m. Successful results have been obtained following exploration of deep reservoirs discovered (about 240°C) at the Kizildere and Tekkehamam geothermal fields (Orhan Mertoglu, Sakir Simsek, Nilgun Basarir, Halime Paksoy, Geothermal Energy Use, Country Update for Turkey, European Geothermal Congress 2019).

Croatia

In 2018, a new legal framework was adopted enabling Croatia to consolidate its energy resources in one place, which is the basis for creating a positive investment climate in a country that rationally manages its resources. Special emphasis was placed on the great potential of geothermal energy. After years of efforts, the first geothermal power plant started electricity production at the very end of 2019. It is located at the well-known Velika Ciglena site, near the town of Bjelovar, where geothermal water outflow with 172°C was found in depths of 2,000 m at the top of a massive fractured carbonate reservoir reaching almost 5000 m in depth. The installed capacity is >16.5 MW and the current output is 10 MWe because of the limited connection capacity of the local power grid. Even that makes it for the time being the largest operating ORC system in the EU. Another innovative advanced geothermal power plant is under development in Draškovec, in the NW of the country. There is also interest for the development of electricity generation in several sites where production and exploration licences have already been issued (Lunjkovec-Kutnjak and Legrad-1, Kotoriba, Ferdinandovac-1).

According to estimates by the Croatian Hydrocarbon Agency, and based on available data from several thousand wells over the past decades, Croatia could well develop geothermal power plants with a total capacity of up to 500 MW. The greatest potential for the exploitation of geothermal energy exists in the continental part, in the Pannonian Basin, where the average geothermal gradient, i.e. the degree of temperature rise is at a depth of as much as 60 percent higher than in the rest of Europe. Translated into actual figures, this means that by drilling up to a depth of two thousand meters, bedrock temperatures of about 100 degrees Celsius can be found, and at a depth of 3,000 m the temperature may reach up to 150 degrees Celsius, which makes electricity production feasible.

In November 2020, the Hydrocarbon Agency of Croatia announced the opportunity for interested parties to be given access to the geothermal potential of the country through a virtual Data Room. In the data room one can remotely study seismic data, well data and key wells that have proven geothermal potential. This Virtual Data Room includes data on 191 key wells, of which 71 are are thought to have electricity generation potential, while 120 are seen as sufficient for heating purposes.

There are 75 blocks identified as promising geothermal areas in the Croatian part of the Pannonian basin, while access to the available data greatly reduces the geological exploration risk. In October 2020 the Croatian Ministry of Economy and Sustainable Development announced its decision on the issuance of geothermal exploration licenses for four exploration areas in the region of Slavonia, Podravina and Medimurje. It is expected that the power generation potential of all four areas is around 50 MW in total. At the end of 2021 the Geo Power Zagoch company was slated to begin the construction of the Slatina 2 geothermal plant with installed capacity of 20 MW. The project is worth US$97,4 million and the facility will be located in Cadavica, Virovitsa in Poctravina county.

Greece

Greece is a country rich in geothermal resources due to active extensional tectonics and volcanic activity. Two high enthalpy geothermal fields (temperatures 280-350 degrees Celisius at depths of 1,000-1,816 m) have been identified on the islands of Milos and Nisyros, both located along the South Aegean Active Volcanic Arc with proven geothermal potential of 30 MWe and estimated possible potential >200 MWe.

Geothermal exploration and exploitation in Greece are defined by Geothermal Law 3175/2003 ("Exploitation of geothermal potential, district heating and other provisions") and the relative Ministerial Decrees. A few amendments were made by Law 3734/2009 (article 37), while the current geothermal legislation classifies the geothermal fields into "high" (T>90oC) or "low temperature" (T<90oC) and "proven" or "probable" fields. As of today, 32 areas have been officially characterized as "geothermal fields" corresponding to more than 40 "proven/probable" and "high/low temperature" geothermal fields.

Presently there is a total absence of power production through geothermal energy. Recently specific plans were tabled by PPC Renewables for a 5 MW power plant on the island of Nisyros. A zero-pollution technology is planned which will ensure uninterrupted power generation on the island, cover desalination needs and also provide district heating for homes and greenhouses. A closed-loop system is proposed where the geothermal fluid will be reintroduced into the subsoil – thus guaranteeing zero gas emissions. Scientific research has been conducted by the National and Kapodistrian University of Athens to investigate if exploitation will pose risks to the geological features of Nisyros. The studies confirmed that no risks are involved from the research, installation, and operation of a geothermal power plant on the island.

In June 2020, PPC Renewables completed the international tender process to select a strategic partner in developing four geothermal high enthalpy fields, a process which had been stalled for two years. The tender was awarded to the "highest bidder", the company ELECTOR, part of the ELLAKTOR group, which hence became a strategic partner for PPC Renewables. The second consortium that had submitted a binding tender, TERNA Energy, was declared an "alternative bidder".

PPC Renewables will now move ahead with the development of four well-known geothermal fields (Lesvos, Milos-Kimolos-Polyaigos, Nisyros and Methana) for which PPC is licensed. The special purpose company will undertake the financing, construction and management of the power plants, 8 MW on Lesvos and 5 MW on each of the others, which will be supplied with geothermal fluid from the drillings. The first exploratory drilling in the geothermal field of Milos was to be carried out by the end of 2021. According to the project schedule, the power plant will be built and become fully operational by 2025.

A new regulatory framework for geothermal investments was announced late in 2020 and was submitted for public consultation. Introduction of this new law is expected to increase the interest by companies for the further development of the sector.

Serbia

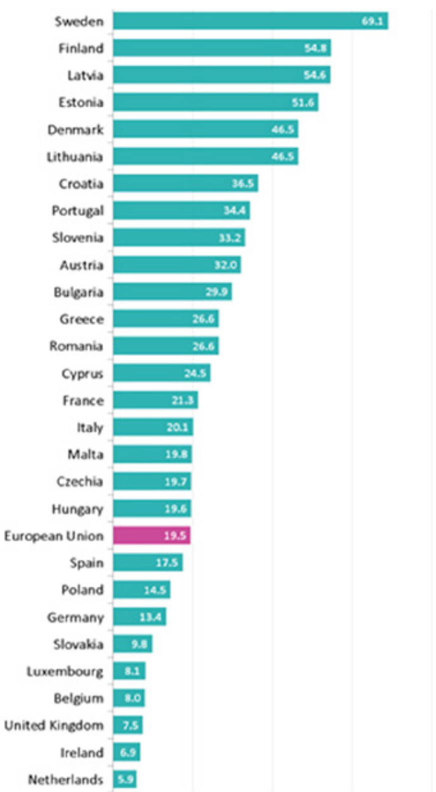
Currently in Serbia there is no power generation from geothermal energy. However, in October 2019, a working group was set up to facilitate the development of the first geothermal power plant projects in the northern province of Vojvodina. In March 2017, the Provincial Secretariat for Energy, Construction and Transport and the French company ES Géothermie, signed an agreement for the establishment of the working group. Its first goal is to create the first geothermal power plants and heating systems for district homes and industry on the existing Vojvodina geothermal field. In 2017, a protocol was signed with the government of Serbia for further cooperation in the field of geothermal energy. Serbia is planning to install 1 MW of geothermal energy in the years to come.

11.3 RES for Heating and Cooling

The EU's Renewable Energy Directive set a target of 32% RES in gross final energy consumption by 2030, with about 40% of this share projected to come from the heating and cooling sectors. Thus, the evolution of climate-related policies is giving new momentum to renewable H&C (RHC) technologies. Heating and cooling in buildings and industry accounts for half of the energy consumed in the EU. 2018 Eurostat data show that 75% of heating and cooling were based on fossil fuels while only 19% were generated from RES. At household level, space heating and hot water alone account for 79% of total final energy consumption. At industry level, space and industrial process heating account for 70,6% of energy consumption. While cooling represents a smaller share, it has been increasing over the last decade.

In order to reach its climate and energy goals, the EU needs to reduce to zero its consumption and use of fossil fuels in the heating and cooling sectors. Controlling energy consumption, reducing energy waste, using intelligent thermostats, renovating and upgrading buildings with the most energy-efficient technologies, as well as improving district heating are all key measures for decarbonising these sectors by 2050.

Figure 11.18 **Share of total energy used for heating and cooling coming from renewables, 2019 (%)**



Source: Eurostat

The main source of RES for heating and cooling in South East Europe derives from biomass, shallow geothermal and solar thermal applications. Huge amounts of renewable heating and cooling can be supplied by solar thermal, geothermal and biomass to satisfy the entire heating and cooling needs of millions of buildings and also to satisfy in part the needs of industry. Many buildings in SE Europe have the potential to be independent of or less dependent on fossil fuels or electricity for heating and cooling. However, progress is much slower in Croatia, Slovenia, Bosnia and Herzegovina, the Republic of North Macedonia and Serbia.

11.3.1 Geothermal Energy for Heating and Cooling

Besides electric power generation, geothermal energy is widely used today for district heating, as well as for heating (and cooling) of individual buildings, including offices, shops, small residential houses, etc. The largest geothermal district heating systems within the EU can be found in the Paris area in France, with Austria, Germany, Hungary, Italy, Poland, Slovakia and others having a large number of interesting geothermal district heating systems. Sweden, Germany and Austria are the leading countries in terms of market for geothermal heat pump applications within the EU.

Bulgaria

During 2014-2018, the installed geothermal capacity for heating applications in Bulgaria increased by 19.6%, from 83.10 MWt in 2014 to 99,37 MWt at the end of 2018 (GSHP excluded). Water supply of mineral water at approximately 32°C to several sea resorts along the northern Black Sea coast increased rapidly. Currently there are only a few balneological sites where thermal water is used for space heating in buildings and domestic hot water applications. Many old heating installations in poor technical condition were abandoned and only a small number of new installations have been constructed.

The renewable geothermal resources in the country have the potential for future direct use development. Currently only about 30% of these resources are being used. The major factors promoting geothermal development in Bulgaria are the long tradition in thermal water use, favourable climate, and appropriate thermal water composition for therapy as well as for bottling of potable water and soft drinks and a well- developed spa system. Over the past years there has been a significant growth in the building of hotels in mountainous and seaside resorts. Most of them use geothermal water for small pools and relaxation areas. Electricity generation from geothermal energy is not currently available in the country but some binary cycle power plants could be built. Obviously, such systems would be of local importance only, because of the very limited geothermal potential for this kind of activity.

Croatia

Croatia's geothermal potential is apparent by the more than 25 natural thermal springs, most of which are used for recreational and medical purposes. Most of them are located in NW and central Croatia (the Pannonian region) but there are also several hypothermal springs along the Adriatic coast (the Dinaric region). Moreover, with the oil and gas exploration and production activities in the Pannonian region, intensely conducted in the second half of the 20th century, many hydrothermal reservoirs were found and some developed, proving the geothermal potential and setting the path for increased geothermal utilisation.

Direct use of geothermal heat in greenhouses is present at Bošnjaci and Sv. Nedelja. Detailed studies have been carried out for the development of geothermal district heating in Karlovac, Križevci, Virovitica, Ludbreg and number of other locations. Finally, the interest for the geothermal energy consumption is raised in numerous Spas, such as Varaždinske Toplice, Velika and others, including shallow drilling (several hundred meters) for the development of a new one in Bjelovar. Use of shallow geothermal energy, through ground source heat pumps (GSHP) is getting more and more developed for use in malls, hotels, industrial and warehouses and individual housing (Živković et al., 2019)

Today, geothermal water is used for bathing and space heating. Out of 18 active spas in Croatia in 6 of them geothermal energy is used for both bathing and space heating while in the rest it is used only for bathing. Geothermal heat is used in most Spas throughout the year as a part of medical rehabilitation system, but several larger Spas are popular as recreation centers.

Beside the Spas, geothermal energy is used for district heating in three locations, i.e in Topusko, Zagreb and Bizovac, and for greenhouses in Sv. Nedjelja and Bošnjaci. Total capacity of this production amounts to 81 MWt. Geothermal water temperatures vary between 25°C and 96°C. Utilization, except in greenhouses where the yield is enhanced by pumping, involves additional surface systems with a low capacity factor, of around 0.27. Therefore, aiming to increase efficiency, with modernization investments of existing systems and the opening of a number of new-ones, could attract additional consumers, while the production of geothermal heat could be significantly higher than today's 300 TJ/y. Very conservative estimates based on 500 deep wells (from among more than 4,000) indicate that there is 750-1300 MWt of geothermal potential available (Kolbah et al., 2018).

Greece

Even though research began over 40 years ago, and a significant number of geothermal fields were identified, utilisation is limited, being exploited solely for thermal spas, greenhouses, soil heating, fish farming, aquaculture, crop drying and Ground Source Heat Pumps (GSHPs). The total installed capacity of geothermal applications in mid-2016 was estimated at 232 MWth, with GSHPs accounting for 64%, thermal spas for 18% and greenhouse heating for 14.5% of this capacity with more than 3,300 installed units. The GSHP market has grown rapidly since 2007 including mostly installations of heating and cooling for residential, office and public buildings as well as hotels, swimming pools and a few agriculture/ industrial applications.

The most important geothermal activities in Greece since 2016 concerned a few new investments in the agricultural sector and to a lesser extent in exploration and exploitation projects.

More specifically, since 2017, a new geothermal greenhouse unit (3.5 ha) was put into operation, another one was expanded from 8 to 17 ha and a third (5 ha) is under consideration. All three units are located in thoroughly studied areas in northern Greece, where the easily accessible geothermal systems and the strong support by local communities and authorities, have created favourable economic and social conditions.

The first geothermal district heating project in Greece is under development in Aristino in Thrace. Fluids of 90˚C will be used for the heating and cooling of twenty public buildings for the heating of greenhouses (4 ha) and the operation of a pellet manufacturing unit. A similar project was recently initiated in Akropotamos (Strymonikos Gulf), but is still in the early implementation phase. Licenses for exploration, exploitation and management of a field (or part of it) are provided by the decentralized administrations (for low temperature fields) or directly from the Ministry of Environment and Energy (for high enthalpy fields). Balneology and the "development of curative tourism" are defined by Law 3498/2006 and the relative Ministerial Decrees. Finally, the exploitation of very shallow geothermal potential using GSHP systems is mentioned in Law 3175/2003 and the relevant procedures are defined by Ministerial Decree.

Romania

The geothermal energy for heating purposes has a great potential for development in Romania. Unfortunately, there has not been any major progress with regard to the shallow geothermal energy sector during 2018-2021. Although Romania was entitled to €100 million of EU money for Axis 6 "Operational Plan for Large Investments", dedicated to less used RES (biomass, biogas, geothermal) and to high-efficiency co-generation systems, there were no investment projects approved in these fields mainly due to political reasons (29).

Most developments in recent years were due to the RONDINE programme, financed by the European Economic Area Grants Financial Mechanism (EEA Grants) and the Romanian Environmental Fund Administration (EFA). One such project was the geothermal space and tap water heating system for the Agrippa Ionescu Hospital in Balotesti, Ilfov County, north of Bucharest. A new geothermal well was drilled near the hospital. After completion and testing, a line shaft pump was installed in the well. It can produce up to 35 l/s geothermal water with a wellhead temperature of about 85°C. The heat plant near the well supplies the primary thermal agent to the substation near the hospital that in turn supplies the space heating agent and hot tap water to the hospital.

The Therme Bucharest Spa Centre is until now the largest private geothermal project in Romania. The company obtained all necessary licences to drill and exploit a new geothermal well, and proceeded to install the shaft pump in the well which supplies geothermal water of up to almost 90°C to the plant located next to the Spa Centre.

Another RONDINE project was carried out in the city of Oradea (western Romania), which has over 40 years' experience in using geothermal energy. A new reinjection well was drilled about 1 km from the production well located at the University of Oradea campus, and a substation built at the Sports Program Highschool not far from the campus. The total annual of geothermal water produced from the production well is about 21,000 m3, of which about 20% is used by the university substation. The annual geothermal energy used in the new substation is about 4,700 MWhth, replacing heat produced by a natural gas fired co-generation power plant in Oradea.

The most important shallow geothermal application in Romania is the ELI-NP Extreme Light Infrastructure, which was built in Bucharest-Magurele. ELI-NP is the first pan-European research facility built in Eastern Europe which focuses on high-level research on ultra-high intensity lasers. The heating and cooling output is in the range of 5.4 MW, for a total air-conditioned area of 27,000 m². The ground source heat exchanger consists of 1,080 boreholes to a depth of 125 m, and the total borehole length is 135,000 m. The total investment cost of about €356 million is paid mainly from Romania's allocation of EU structural funds.Romania is lagging behind with the implementation of the European Directives dealing with the RES use in heating and cooling and the energy efficiency measures applied to government, public and administrative buildings, and for investments realised with state funds. The legislative measures concerning the shallow geothermal sector are a real barrier against its evolution and development. The adoption of the new European standards for water boreholes and geothermal boreholes will be more than welcome.

Serbia

At present (2019), geothermal energy production corresponds to 112.86 MWth with an additional 15.59 MWth concerning shallow systems. This can be considered as pretty low keeping in mind Serbia's large geothermal potential. The most significant use of geothermal energy in Serbia is for the district heating of settlements and in the agricultural sector, more precisely for food production in accordance with ecological standards for power generation.

Even though Serbia has a great energy potential related to direct use of geothermal energy, very few investors have chosen to get involved in this field. The reason is the very high cost of the systems involved, but also because of complex regulatory and licensing framework currently in force. Most investors appear to be interested in using geothermal energy from shallow systems only as a more secure investment. In this way since 2018, over 10 geothermal projects for heating have started operation in mountain resorts and commercial and residential buildings. The great interest is in Belgrade with the use of heat pumps for heating large state-of-the-art residential buildings, hotels and shopping centres where reservoirs are to be found in the alluvial sediments of the Sava and Danube rivers and the Neogene sediments beneath. In addition, the prospects for the use of heat pumps in pumped ground water from alluvial deposits along all major rivers are most promising. According to the latest geothermal exploration results, intensive use of thermal waters in agro- and aqua- culture and district heating have the best prospects in the area west of Belgrade, in Macva.

In the settlement of Bogatic, a district heating system started operation in 2018 with a capacity of 2.62 MWth, while another with a capacity of 8.49 MWth is planned for agricultural purposes. Both systems are using geothermal energy from reservoirs in karstified limestone beneath the Neogene sediments.

French company IEL OIE Balkan Renewable Energy in November 2020 announced plans for a geothermal power plant in Serbia for district heating. French giant EDF is participating in the project. Feasibility studies for the construction of geothermal plants for Vranje, Subotica, Kikinda and Ruma have been conducted. The above projects concern the production of thermal energy for district heating applications.

Turkey

Turkey has made impressive progress in the utilisation of geothermal energy for heating applications over the last 5 years. Today, 17 cities are heated partly with geothermal energy. These geothermal district heating systems have been constructed since 1987 and much experience has been gained at both the technical and economic level.

The first geothermal cooling application was realised in 2018 in Izmir-Balcova by Izmir Jeotermal Inc. This involved the cooling of a 1,900 m2 indoor area using lithium bromide absorption at 90/85°C geothermal temperature regime by supplying 6/9°C clean cold water to the coolers in the buildings.

Turkey's 2025 target for geothermal direct use including geothermal heating like district heating, greenhouse heating, thermal facilities heating and cooling and balneological use has been estimated at 7,000 MWt.

Direct-use applications have reached 3,487 MWt of geothermal heating, including district heating (1,033 MWt), a 4,3 million m2 greenhouse heating (820 MWt), thermal facilities in hotels etc. with heating capacity of 420 MWt, balneological use (1,205 MWt), agricultural drying (1,5 MWt), geothermal cooling (0,1 MWe), (HP) heat pump (109 MWt) and ground source heat pump applications (7,6 MWt).

Ground Source Heat Pump (GSHP) applications in Turkey started in the 2000's for residential single family houses with a total installed capacity of 586 kWt. Today, with increased interest in renewables, the number of GSHP systems has reached 146 with a total installed capacity of 109 MWt. Open systems using sea, lake and groundwater correspond to about 91% of total installed capacity while 55% of the open systems use sea water as their source. Closed systems consist of vertical, horizontal and energy pile applications. Eighty-nine of the GSHP applications are closed systems with installed capacity of 7.6 MWt. In recent years, a new source of waste from baneological heat is being utilised. There are three such applications so far that correspond to 4% of installed capacity.

The potential for heating residential and commercial properties such as hotels, swimming pools and greenhouses is estimated at 30,000 MWth. According to the Turkish Geothermal Power Plant Investors Association (JESDER), the country has the opportunity to build up additional geothermal capacity of 200 to 250 MW per year with annual investments of approximately US$1 billion. The payback period is estimated at about five years. JESDER estimates the cost of drilling a geothermal well of up to 4,000 meters deep and requiring 60 to 80 days of work is estimated to cost between $3 million and $4 million.

In the Western Turkish provinces of Denizli, Manisa and Aydin, where there are numerous geothermal sources, special zones have already been identified in which wastewater from geothermal power plants is to be used to heat greenhouses. Of particular note is the project in the Sarayköy area near Denizli, where greenhouses will be built on an area of 650,000 m2, which will house the wastewater from the Zorlu Enerji power plant. A similar project is planned in the Efeler area near Aydin.

11.3.2 Biomass

Biomass heat applications contribute almost 98% of renewable heat production in Europe. The main part of this contribution comes from domestic heating with fuel wood, followed by large-scale use of biomass waste for industrial processes, heat applications and biomass use in district heating plants.

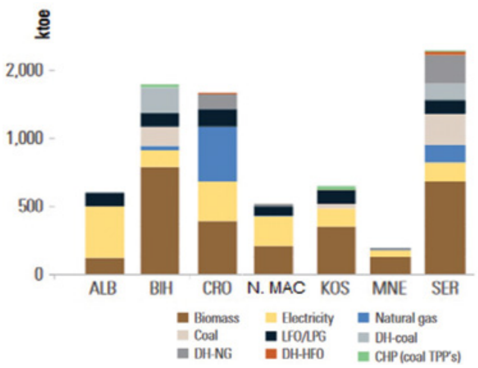
Biomass offers considerable flexibility of fuel supply due to the range and the diversity of fuels which can be produced at small or large scale, in a centralised or decentralised way. Cogeneration applications allow making particularly efficient use of biomass by combining the generation of heat and electricity from renewables in one process. The cost of heat production from biomass, or bio-heat, depends firstly on the bio-fuel cost. Costs depend on the country, the type and quality of the fuel, the demand, the organisation of the procurement chain, and the quantity. (30)

In most South East European countries, biomass is the most important heating energy source, in both rural and urban areas, accounting for 42% of the energy required for heating. In most rural areas in SEE, biomass is abundant and constitutes the primary source of heating for the majority of the population. Rural households account for 63% of total biomass consumption, and urban households account for 37%. Unfortunately, a significant share of biomass is used inefficiently because of outdated equipment and the lack of wood drying before use. Apart from the loss of 40-50% of the energy content and higher energy costs of heating due to such practices, resulting particulate emissions contribute significantly to poor air quality in cities.

In the residential sector, firewood is the most common fuel in most West Balkan countries (Bosnia-Herzegovina 76%, Croatia 49%, North

Macedonia 63%, Kosovo 72%, Montenegro 65%, and Serbia 60%). The exception is Albania, where electricity is the prevailing heating method.

Figure 11.19 **Annual Heat Demand in W. Balkan Countries (2018)**



Source: WB Biomass-Based Heating in the Western Balkans – A Roadmap for Sustainable Development

Albania

The current use of woody biomass in Albania exceeds the annual forest growth increment by 46%. In Albania, current biomass use relies mainly on high-value stem-wood with the trend toward higher utilisation of forest residues (logging residues, thinnings). Biomass use for heating is very inefficient (60% of biomass is used in wood stoves and is not properly dried). Hence, it is necessary to support local manufacturers on product development of low emissions combustion systems, especially in the small and medium-scale heating sector. The goal will be to achieve an increase in biomass utilization for heating without increasing other harmful emissions. The potential for energy crops should be further explored and would require concerted efforts for years in order to enable such crops to reach markets. In Albania, 18% of agricultural land is not currently used.

Bosnia-Herzegovina

Biomass consumption could contribute 50-75% of heating needs in achieving the set renewable energy goal for B-H, which is 40% RES in gross final energy consumption by 2030. Considering that fuelwood consumption in households contributes to over 90% of total biomass consumption, the relevant data in this sector need to be carefully evaluated in order to decide on the most appropriate methodological approach for establishing an accurate value. Establishing the correct amount of biomass household consumption remains difficult, due to the large number of unregistered cuttings and harvesting of biomass in B-H and the strong variation in terms of qualities, densities and quantification of firewood.

Table 11.8 **Quantities of biomass consumption in B&H**

	2014	2015*	2016	2017
Biomass Household Consumption (ktoe)	1041,53	1083,29	1187,23	1164,63
Other fuels in Households (w.o.electricity) (ktoe)**	252,53	262,65	287,85	282,37

*Baseline year for calculation

** According to EUROSTAT/BH Energy Balance

Source: Energy Community: BiH RES Progress Report 2019)

Efforts to promote larger use of forest and agricultural residues for heating in rural settlements through projects have not yielded any significant results and the main reasons are:

- insufficient regulatory framework in the forestry sector,
- insufficient access to forests,
- lack of regulation in the heating sector,
- undeveloped infrastructure,
- low awareness about the significant potential of biomass.

Bulgaria

Currently, 66% of the population in Bulgaria uses biomass for space heating. More than 1,000,000 households use forest biomass for heating (90% in rural areas). Almost all households burn wood for heating in old and low effectivity ovens –open burning with less than 40% efficiency. Unfortunately, there is little interest in investment in modern heating installations for wood biomass, even in communities close to forests. Furthermore, there is no experience in long-term contracts in wood and timber markets so as to secure an abundant resource for heating but also to support investments in industrial processes.According to the National long-term programme for encouraging the use of biomass for the period 2008-2020, the aim is sustainable and independent energy development by mobilising energy recourses from renewable and alternative sources, with timber biomass being the biggest source of bioenergy in the country.

In Bulgaria, the use of renewable energy for heating and cooling, is promoted through a grant from the Bulgarian Energy Efficiency Fund and through an exemption for building owners from property tax. The following policies aim to promote the development, installation and usage of RES-installations in Bulgaria:

- There is a professional training programme for RES-installers and an obligation to use renewable heating in buildings, including biomass, and for public authorities to play an exemplary role.
- Installers of renewable energy facilities have to be registered and certified by the State Agency for Metrological and Technical Surveillance.
- Buildings with a useful total built-up area (TBA) over 500 m2 and occupied by a public body or frequently visited by citizens, are subject to an obligatory energy efficiency audit and have to provide an energy performance certificate.
- Any investment project for a new building with a total floor coverage of over 1000 m² must comply with the provisions regarding the use of decentralised systems based on renewable energy. In these buildings, at least 15 percent of the total heating and cooling needed for the building must be produced from renewable sources.

Croatia

The total primary energy supply of renewable energy sources in Croatia is mostly covered by biomass, which contributes 65% of RES production (54 PJ). More than 96% of the bioenergy consumed in Croatia comes from solid biofuels (52 PJ) for heating, of which most (47 PJ) is to be found in the residential sector. The role of biogas (2 PJ) for electricity production is much smaller. Biodiesel, biogasoline and energy from municipal waste (MSW) were negligible in 2018.

Table 11.9 **Role of bioenergy and renewable energy in electricity production, transport energy consumption and fuel/heat consumption in Croatia (2018)**

Sector	Share of bioenergy	Share of renewable energy	Overall production/ consumption
Electricity production	3.4%	66% (Hydro: 45%)	12.6 TWh (45 PJ)
Transport energy (final consumption)	0.0%	0.7%	85 PJ
Overall fuel and heat consumption[3]	Direct biomass: 36.4% Biobased heat: 0.7%	37.8%	132 PJ

Source: World Energy Balances, OECD/IEA 2018

In 2016, the national energy balances were corrected for the supply of biomass (wood fuel). The outcome of the nationwide survey on fuel consumption in households based on 2011 census, revealed that 53.36% of gross final energy consumption in Croatian households is related to solid biomass, with 95% concerning space heating. Only 0.56% of the share of biomass is attributed to modern biomass fuels.

Greece

The pellet market in Greece has been developing rapidly over the last six years. Government austerity measures during the deep economic recession of 2010-2018 resulted in higher taxes for fossil fuels, at a time of considerably reduced average national income. This led to more than 1.5 million households abstaining from the use of oil and gas after 2013, with consumers seeking alternative economic heating solutions (mostly electricity but also pellets). Following the lift of restrictions for burning biomass in urban areas (with almost 40% of residences affected), around 40,000 households used pellets for heating in 2017, while the average monthly consumption of biomass (including fuel-wood, pellets, olive kernel etc.) had increased by 20.7% by 2016. 2018 estimates on annual pellet consumption ranged from 90,000 to 120,000 tons, while the potential of market growth appears to be significant.

In particular, the rate of biomass use for thermal energy production in Greek households increased by 12% (2017) while the corresponding figure for pellet use alone increased by 0,7% (2018)[11, 12].

[11] Source Hellenic Biomass Association (ELEABIOM)
[12] Source Hellenic Biomass Association (ELEABIOM)

In 2020, over twelve small and medium pellet producers were operating in Greece with a total nominal capacity of 130,000 tons per year. Actual production rates remain quite low, mainly due to the lack of raw material availability and the increased competition from neighbouring countries. Greece covers 33% of its pellet demand from imports, mainly from Bulgaria and Romania, and the remaining percentage is covered mainly by four Greek pellet production plants.

The unexpected vertical market growth resulted in an uncontrolled mass consumption of poor quality pellets and non-certified heating systems leading to high emissions of micro-particles and nitrogen oxides, as well as to end-user problems. The consumers' financial benefit of using pellets compared to oil, the affordable 'pay as you go' manner of consuming pellets, the emerging opportunities for entrepreneurship and job creation, as well as the activation and synergies of pellet market stakeholders could potentially foster further pellet consumption and production in the country in the years to come.
Certain obstacles that still hinder the adoption of pellet heating systems by Greek households need to be tackled. These mainly include the lack of attractive financial incentives for the purchase of pellet boilers/stoves, poor and inaccurate information to consumers, and domestic pellet production bottlenecks.

The Greek pellet market has been developing since 2006. The first production plant started operation in late 2006 when there was no real consumption in the country. Total production in 2008 was 27.800 tons, while installed production capacity was 87.000 tons. At that time there were some wood industries that had started pellet production mostly by using their own wood by-products. Some companies appeared in 2009, installing pellet-producing machinery with the help of European subsidies. Total installed capacity of pellets production in 2020 was estimated at more than 100.000 tons[13].

However, pellet consumption in Greece, especially in households, remains at very low levels. Wood by-products are usually being used without any processing, mainly for heating purposes in the agricultural sector. There is a number of small and medium-sized manufacturers producing boilers for biomass use, which also supply the market, for pellet use.

Montenegro

Use of annual forest growth increment is lowest in the Western Balkans (41%), thus creating a solid base for increase of bioenergy use. In Montenegro, current biomass use is based on high-value stem wood with little use of forest residues (logging residues, thinnings). The potential for energy crops should be further explored and would require consistent efforts by several entities to fully exploit it. In Montenegro, 57% of agricultural land is not currently used.

Use of biomass for heating in Montenegro is already high thought to be the highest in Western Balkans (68% of current heat demand), but very inefficient (41% of biomass is used in traditional, inefficient stoves, and not properly dried). Limited availability of efficient technologies needs to be addressed through technical standardisation and certification of heating appliances, and raising awareness among manufacturers and consumers. Support to local manufacturers on product development toward low emissions combustion systems is needed, especially in the small and medium scale heating sector in order to achieve an increase in biomass utilisation without increasing other harmful emissions.

Conversion of inefficient firewood stoves (360 MW) with an investment of €18.8mn would create multiple benefits: It would generate annual savings in energy costs of €36.1mn; reduce GHG emissions of approximately 7,100 tCO_2eq ; save more than 178,000 m^3 of wood worth around €6.5mn a year; and reduce dust emissions of 99 tonnes, equivalent to 40% of air pollution coming from inefficient stoves.

[13] Source Hellenic Biomass Association (ELEABIOM)

Kosovo

Unregistered logging is an issue which needs to be addressed in order to prevent deforestation. Current use of woody biomass exceeds the annual forest growth increment by 56%. Thinning of forests should be promoted to facilitate the growth of high value wood, and so increase biomass supply with the resulting residue. Changes in the structure of use of woody biomass are needed to ensure sustainability.

In Kosovo, current biomass use is mainly based on high-value stemwood. The potential for energy crops should be further explored and would require considerable efforts over many years. In Kosovo, 41% of agricultural land is not currently used. There is high use of biomass for heating with 54% used for heating. Biomass use for heating is very inefficient (38% of heat demand is covered with wood stoves of very low efficiency). The limited availability of locally manufactured efficient technologies needs to be addressed through technical standardisation and certification of heating appliances, and awareness raising of manufacturers and consumers.

North Macedonia

North Macedonia is already using 85% of its annual forest growth increment, while changes in the structure of woody biomass are needed to ensure sustainability. Like other West Balkan countries, North Macedonia uses biomass of mostly high-value stemwood, while the potential for energy crops appears to be considerable. In North Macedonia 38% of agricultural land is not currently used.

Biomass use for heating is already high (39% of current heat demand), but mainly inefficient (74% of biomass is used in traditional, inefficient stoves, and not properly dried). Limited availability of locally manufactured efficient technologies needs to be addressed through technical standardisation and certification of heating appliances, and awareness-raising among manufacturers and consumers. Support to local manufacturers on product development toward low emissions combustion systems is needed, especially in the small and medium scale heating sector, to achieve increase in biomass utilisation for heating without increasing other harmful emissions (such as PM). Conversion of all inefficient firewood stoves (1,110 MW) to efficient mechanisms in North Macedonia requires an investment of €57.3mn. It would generate annual savings in energy cost (including externalities) of €107.8mn, and the benefits would include reduction of GHG emissions for 21,140 tCO_2eq, saving more than 525,000 m^3 of wood, worth around €19.3 M, and an annual reduction of dust emissions to air of 296 tonnes, equivalent to 40% of air pollution coming from inefficient stoves[14].

Romania

Biomass is and is ikely to remain the main renewable fuel in Romania for heating purposes. The main form of energy biomass produced in Romania is firewood (95%), being an important generator of GHG. Data on solid biomass production of 42 TWh in 2015 are highly uncertain. Household firewood consumption is estimated at 36 TWh. Biomass is predominantly used in the production of heat and electricity in cogeneration systems. Romania has a significant forestry potential of wood and plant to support the production of quality pellets and briquettes. Over 28 producers of pellets and briquettes are registered. As the prices of gas, petroleum products and electricity have been effectively increasing over recent years, pellets and briquettes have emerged as competitively priced alternatives.

According to 2020 estimates by the Ministry of Economy and the Ministry of Agriculture and Forestry, pellets and briquettes production capacity will soon exceed 1.2 million tonnes / year. Domestic consumption is relatively low, due to the lack of pellets and briquettes stoves and power plants. Pellets in Romania as a fuel type product is little known and little advertised. This has contributed to their high acquisition costs compared to fuel oil and gas. Another major reason for the low rate of consumption has been the poor quality of pellets (large

[14] Biomass-Based Heating in the Western Balkans – A Roadmap for Sustainable Development, October 2017, World Bank Group

amounts of ash, dirt, high humidity, low durability) which influenced the choice of potential consumers.

Serbia

Serbia is already using 99% its of annual forest growth increment, characterised by a large share of unregistered logging—more than 51%- while the current biomass use is based on high-value stemwood with very little use of energy crops. In Serbia, 32% of agricultural land is not currently used while the use of agricultural residues, to be found in the north part of Serbia (Vojvodina and Mačva regions) and in parts of the fertile Pannonian Basin, should be further developed. Already there is high use of biomass for heating (41% of current heat demand), but it is still inefficient (28% of biomass is used in old wood stoves). There is limited availability of locally manufactured biomass production. Efficient technologies needs to be introduced through technical standardisation and certification of heating appliances, and awareness-raising among manufacturers and consumers.

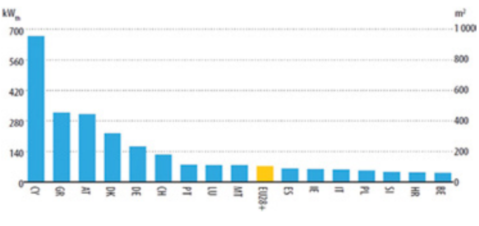
As in other countries in SEE, it is necessary to support local manufacturers in product development toward low emissions combustion systems, especially in the small- and medium-scale heating sector, in order to achieve an increase in biomass utilisation for heating without increasing other harmful emissions (such as PM)[15]. According to a World Bank Group Report (2017), conversion of all inefficient firewood stoves in Serbia to efficient ones (1,170 MW) by investing €60.2mn would generate multiple benefits, including annual savings in energy costs (including externalities) of €131.8mn, reduction of GHG emissions by 27,800 tCO_2eq, savings of more than 691,000 m^3 of wood worth around €25.4 M, and annual reduction of dust emissions of 391 tons, equivalent to 40% of air pollution coming from inefficient stoves. It has been estimated that switching electric heating appliances to efficient firewood stoves (313 MW) in stand-alone buildings, by investing €11.4 M would generate annual savings in energy costs of approximately €34.7 M, and the benefits would also include reduction of GHG emissions of 939,100 tCO_2eq, saving of 969 GWh of electricity (valued at €58.1 M). However, such an approach would increase dust emissions to air by 118 tons annually, but the benefits of GHG emissions reduction outweigh the marginal increase in PM emissions.

11.3.2 Solar Thermal

Solar thermal applications provide renewable heating at a very competitive cost and have a very wide range of application potential in all SEE countries. The most common applications are for domestic hot water (SWH) and space heating. SWH systems are available in the market also for swimming pool heating, desalination and process heat for tertiary, agricultural or industrial purposes.

The solar thermal capacity in operation today (kWth/1,000 capita) varies from 608 in Cyprus, to 166 in Austria, 5 in Italy and 3 in France. Such differentials are, obviously not linked to natural resources, but show the huge potential for growth at EU level. Solar thermal alone could replace more than 30% of the EU's oil import bill. Solar-assisted cooling is another very promising technology, as peak cooling consumption coincides with peak solar radiation. A number of large-scale solar cooling systems have been successfully demonstrated, but it is now necessary to support wide market introduction. Small-scale solar cooling systems could be ready within a decade, if R&D support is provided.

Figure 11.20 **European solar thermal capacity in operation (per 1000 capita)**



Source: Solar Heat Europe, 2020

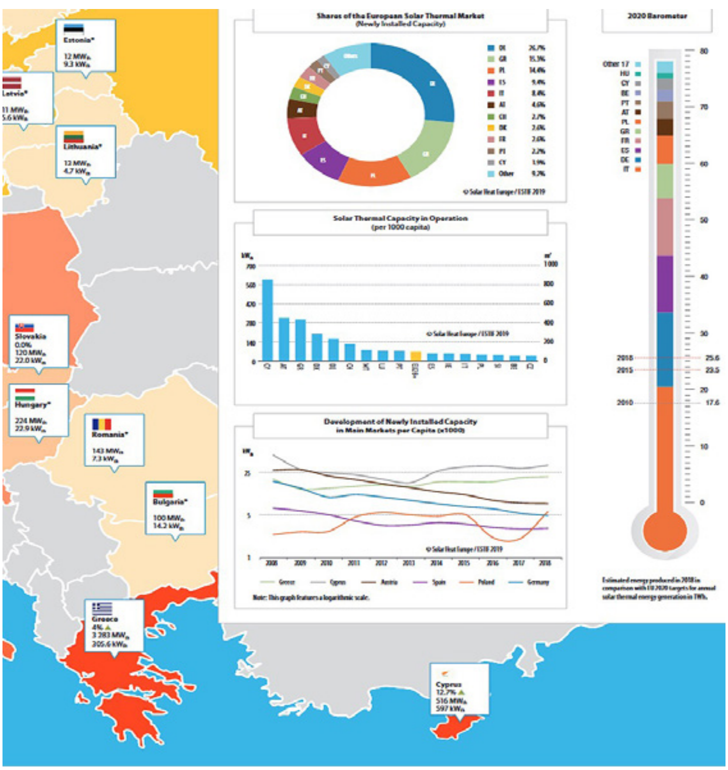
[15] "Particulate matter" (PM) is the general term used to describe solid particles and liquid droplets found in the air. The composition and size of these airborne particles and droplets vary.

The estimated total thermal energy generation of solar heating and cooling systems operating in Europe corresponds to 25.6 TWhth. This is equivalent to 92.1 PJ or 2.2 Mtoe of energy, an amount that would be enough to supply the annual heating demand of Cyprus and Estonia.

Nevertheless, this level of energy generation falls short of the 78 TWhth which represents the indicative target for solar heating and cooling by 2020, as foreseen in the National Renewable Energy Action Plans adopted by EU member states. Solar thermal is part of the policy to lower reliance on imported oil and gas by reducing the use of fossil fuels for heating and cooling, while at the same time helping in the reduction of GHG emissions. In 2018 alone, an equivalent of 6.8 Mt CO_2 emissions was prevented in the EU thanks to Solar Water Heating systems. Furthermore, SWH is probably the most environmentally-friendly renewable solution, considering the full product lifecycle, from manufacturing to decommissioning and recycling. In what concerns economic aspects, the solar heating and cooling sector achieved a combined turnover of €1.85 billion in 2018, employing approximately 18,800 people (31).

The evolution of the installed capacity has been rather heterogeneous across countries and market segments. The most impressive development was observed in Poland, given the success of programmes addressing air quality in cities and supporting the reduction of harmful emissions. Consequently, the Polish market reached 217 MWth, growing by a staggering 179% in 2018. Another market with double-digit growth that year was Denmark (+77%). The fact that the Danish government resumed the support framework (that had expired by the end of 2016) meant that ten large solar district heating projects (new or extensions) were finalised already during 2018, with a combined capacity close to 40 MWth.

Map 11.3 **Solar Thermal Installed Capacity in SE Europe**



Source: Solar Heat Europe, 2020

Regarding the residential sector, we should observe that countries whose systems combined space and water heating capabilities (solar combi-systems) represent a large segment of the market. SWH system sales in western European countries have been in decline in recent years in direct contrast to Central and SEE countries, where domestic hot water systems have shown growth once again. Greece, Spain and Portugal grew between 2% and 4%, while Cyprus led the way with a 14% increase. Cyprus is also the foremost country in terms of total installed capacity per capita, with 0.6 kWth installed per Cypriot, corresponding to approximately 0.85 m^2 of collector area. In terms of consistent market growth, the biggest accolade goes to Greece, which grew for the 9th year in a row. This is also due to an increased competition among the Greek solar thermal manufacturers and the capacity to reduce product costs. In this market, solar water heater retail prices can go as low as €285/kWth (including energy storage).

SE Europe

According to IRENA, Central and South Eastern Europe could use renewables to meet 34% of their heat demand by 2030, with solar thermal installed in buildings being the cheapest replacement option for fossil fuel equipment. The 2030 solar heat potential of all Central and SE European countries (Bulgaria, Croatia, Cyprus, Greece, Hungary, Romania, Slovakia, Slovenia, Albania, Bosnia and Herzegovina, Kosovo, Montenegro, North Macedonia, the Republic of Moldova, Serbia and Ukraine) combined is estimated at 93 GWth, or 133.1 million m^2 of collector area. According to IRENA most CESEC members (Central and South Eastern Europe Energy Connectivity Initiative) could substantially increase their use of solar thermal, "which has the potential to reduce demand for fossil fuels in the region's heat sector by about 3% in 2030."

In addition to increased electrification, solar thermal can provide affordable hot water in residential and commercial buildings, as well as competitive low-temperature heat for certain industry subsectors. Table 11.10 shows what amount of collector area needs to be installed in each country by 2030 in order to provide the expected solar heat contribution in the building and industrial sectors. The corresponding collector area was calculated using an estimated specific yield of 500 kWh/m^2.

Table 11.10 **Solar heat potential as a share of final energy consumption by 2030**

	Industry REmap 2030 [PJ]	Buildings REmap 2030 [PJ]	Remap total 2030 [PJ]	Total GWh	Corresponding collector area [m^2]
Albania (AL)	0.24	2.9	3.14	872.2	1,744,400
Austria (AT)	4.44	13.4	17.84	4,955.6	9,911,200
Bosnia and Herzegovina (BA)	0.22	2.2	2.42	672.2	1,344,400
Bulgaria (BG)	1.17	2.8	3.97	1,102.8	2,205,600
Croatia (HR)	0.81	3.7	4.51	1,252.8	2,505,600
Greece (GR)	1.50	21.9	23.4	6,500	13,000,000
Hungary (HU)	1.78	8.5	10.28	2,855.6	5,711,200
Italy (IT)	11.05	92.9	102.14	28,372.2	56,744,400
North Macedonia (MK)	0.21	1.9	2.11	586.1	1,172,200
Moldova (MD)	0.40	1.9	2.3	638.9	1,277,800
Montenegro (ME)	0.31	0.0	0.31	86.10	172,200
Romania (RO)	3.25	15.8	19.05	5,291.70	10,583,400
Serbia (RS)	3.49	5.5	8.99	2,497.22	4,994,440
Slovakia (SK)	1.34	5.4	6.74	1,872.22	3,744,440
Slovenia (SI)	0.55	2.4	2.95	819.44	1,638,880
Ukraine (UA)	4.32	20.0	24.32	6,755.6	13,511,200
Kosovo (XK)	0.16	1.3	1.46	405.6	811,200
Cyprus (CY)	0.05	3.6	3.65	1,013.9	2,027,800
			239.58	66,550.2	133,100,360

Source: CESEC report / IRENA

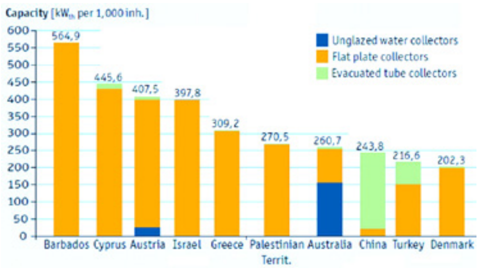
Greece

Solar thermal energy in Greece

Greece has a very vibrant solar water heating sector thanks to high consumer interest and a very successful local solar industry. More than 1.5 million Greek households cover 80-90% of their hot water needs from installed solar water heating devices on their rooftops. It is estimated that the current installed flat plate collector area, including hotel, hospital and industrial applications, exceeds 5.0 million square metres and corresponds to €1.0 billion in annual energy savings. Furthermore the contribution of solar water heating in terms of national energy savings is substantial as these correspond to the yearly output of a standard 400 MWe conventional thermal power generating plant.

11

Figure 11.21 **Top 10 countries of cumulative water collector installations per 1,000 inhabitants in 2019 (relative figures in kWth)**



Source: Hellenic Federation of Solar Industries (EBIE)

Greece today ranks 5th globally in terms of installed area per 1,000 inhabitants (see Fig. 11.21). The installed capacity of solar operating collectors is approximately 3,283 MWth (data 2019). Almost 95% of installed solar heating appliances is manufactured locally with Greek solar manufacturers (see www.ebhe.gr). According to the latest figures, the country' s 21 major solar water heating industries produce some 400,000 m^2 of flat plate solar collectors, 60% of which is being exported to other European countries but also to Africa and the Middle East (see Map 11.4).

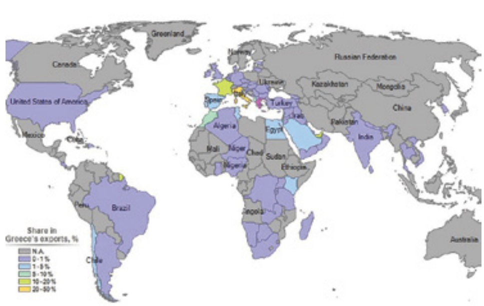
The success of Greece's solar water heating market can be attributed to a number of factors such as the existence of a large energy-conscious local market, the high quality of the manufactured products following the early adoption of strict production standards and the competitive pricing of sold products. Retail prices of solar heating systems (2020 prices) can be as low as €285/kWth

Over recent years the quality and efficiency of flat plate solar collectors has significantly improved. Greece is currently ranked third in the European market in terms of installed surface collectors. It is noteworthy that Greece is the largest exporter of SWH systems throughout Europe, even providing products to countries with a large industrial base such as Germany. In this respect the Greek solar thermal industry is an export champion: The total collector area sold to customers abroad tripled from 200,000 m2 to 600,000 m^2 in only 10 years (see chart).

Greek manufacturers took advantage of opportunities around the world while demand for their cost-competitive and reliable products also grew at home. In Greece, solar thermosiphon type systems dominate solar thermal sales, providing the bulk of household hot water demand annually, as the country enjoys high solar radiation level throughout the year.

Strong local branding means importers have little chance of getting their products to consumers. International Trade Centre data under HS code 841919 indicated that Greek manufacturers have a wide distribution network across the world. The HS code is used for non-electric instantaneous water heaters and storage water heaters, excluding instantaneous gas water heaters and central heating boilers. Most Greek solar thermal products are exported under this code. Map 11.4 shows the key export areas of Greek SWH all over the world. According to the information provided in the map, based on 2019 data, Italy is an important export market (21% of sales), followed by France, the United Arab Emirates and French Guyana (14% each). The third category of countries consists of Morocco (7%), Albania (6%), Portugal (5%), Chile and Egypt (3%) as well as Saudi Arabia, Kenya and Spain (2%). Only 1% each went to Tunisia and to the United States.

Map 11.4 **Greece's export solar thermal products markets in 2019**



Source: Solarthermalword

The recent recession heightened competition between manufacturers as it sent retail prices downwards. New taxes in Greece led to a 120%

spike in the cost of heating oil (used for central heating systems) between 2010 and 2018, and energy became more expensive because the government also introduced renewable energy and carbon emission taxes. Only natural gas remained nearly affordable, but the national gas grid supplies less than a fifth of Greek households.

Some governmental support and new business models spurred demand during the recession. In 2010, the Energy Efficiency Building Regulations made it mandatory that solar systems be used to meet at least 60% of hot water demand in all newbuilds. A PV solar system on the roof is allowed only if a solar water heater system is already installed. Since 2010, very low-income families have been able to request a 70% incentive subsidy for their solar water heater from the "Energy Saving at Home" programmes. After online suppliers and large electrical and home appliances chains entered the market, it has become even easier for customers to buy SWH systems.

Cyprus

The island is already one of the highest users per capita worldwide of solar water heating systems in houses, with over 90% of households equipped with SWH and over 50% of hotels using large solar systems to cover all their hot market needs. With almost year-round sunshine, Cyprus certainly has plenty of energy to harness, but competitive energy-storing capabilities are crucial in order to fully tap into its solar potential and facilitate better RES penetration. Cyprus is among Europe's top countries for using renewable energy sources for heating and cooling through solar heating. In 2018, renewable energy accounted for 21% of the total energy used for heating and cooling in the EU, while in Cyprus it was much higher at 37%.

Homeowners and businesses in Cyprus have shown growing interest in solar thermal technology in past years. Collector area additions on the island increased by 5% in 2018 and by 24% in 2019 after a small decline in 2017 (32). The growth in collector capacity was the result of an improving economy and the grants that the government offered for residential solar thermal systems. The country's grant scheme for solar water heaters has been in place since 2006, although the budget for incentives is revised and approved on an annual basis. In 2019, the government made €300,000 available to fund about 1,000 systems. Replacing an entire system is supported with €350; changing only the collector panels will net applicants €175.

The currently 700,000 m2 of total solar collector area in operation on the island has resulted in the world's highest rate per capita. Due to market saturation, with solar thermal systems in more than 90% of households, some business representatives are sceptical about further prospects of market growth. Current demand for thermosiphon systems is down to a quarter of 2008 demand. Hence, the industry is increasingly focusing on exports and on the replacement of older systems, with new builds representing a very small segment at present.

Turkey

Turkey is among the largest developing markets for solar heating systems. By 2018, the area of installed solar collectors in Turkey had reached over 25 million m² (Solar Heat Worldwide, 2020 Edition). By using solar collectors to this extent, heat energy equivalent to approximately 1.1 million-TEP was generated, by a rough estimate based on numbers given for previous years. About 0.75 million TEP of heat energy was used in dwellings whereas 0.35 million TEP was used for industrial applications.

With nearly 1.88 Million m² of collector area newly installed in 2018 (1.33 GWth), Turkey appears to be the largest solar thermal market in Europe and the second-largest in the world, followed by China. The share of high efficiency vacuum tube collectors has increased significantly over the years, and currently represents half of all installed solar thermal collectors. According to latest available market surveys for solar thermal industry trends (33), multi-family houses were considered the fastest-growing segment in Turkey, favored by 52% of the vote of the survey participants. Another 17% considered single-family houses to be the most important segment, 14% opted for the tourism sector, 10% for the public sector and 7% for industrial process heat. The most typical SWH product is the individual thermosyphon solar system with two flat plate collectors, each nearly 2 m². This market is considered to be mature and widespread throughout the country. Vacuum tube technology has been gaining ground in the Turkish market in the last decade. The share of vacuum tubes among the newly installed collector area in the country increased from 10% to nearly 50% between 2008 and 2018. Thermosyphon systems with a vacuum tube collector, having 1.6-3.0 m² area, have become very popular in recent years.

The main market driver for the classical thermosyphon solar system with a single tank is its relative affordability and easy-payment method provided by marketing companies. Its efficient use is further enhanced by the high solar radiation of the country and the relatively high prices of conventional fuels. The market nowadays is very buoyant for newly constructed industrial or commercial facilities, because it can take just three or four years for a solar thermal system to pay back its installation costs, as opposed to the five or six year payback time for natural gas systems. It is important to note that public awareness of solar water heating benefits has been very high in Turkey. The generous hot water output of this user-friendly, mature technology makes it very attractive for domestic applications, especially in the southern and western provinces.

Turkey has no incentives for the installation of solar water heaters except for families living in remote areas ("forest villages") who receive interest free credit by covering 100% of the investment cost, which is repaid in three equal instalments. Between 2004 and 2013, some 132,000 families living in rural areas have received such subsidies for solar water heaters from a project funded by the General Directorate of Forestry, Department of Forest and Village Relations (ORKOY), which supports habitation near forest areas in order to avoid deforestation. Recent regulations on renewable energy use along with energy efficiency requirements (BEPD of Turkey) have created many opportunities for the solar energy and HVAC industry. The National Renewable Energy Action Plan of Turkey has supported this trend and set a new target for the share of renewables in gross final consumption for heating and cooling from 14.16% from 12.54%. Turkey's solar heating industry is well developed with high quality manufacturing and export capacity. The number of manufacturers and retailers for solar thermal system has dropped over the last five years. As of 2020, it is estimated that there were 70 manufacturers and 500-600 retailers throughout the country. The number of large manufacturing facilities, involving export and distribution activities has on the other hand decreased to nearly 10-15, in the last five years. According to a solar thermal market survey in 2019, two Turkish manufacturers (Eraslan as 11th and Solimpeks as 15th) have been included in the top 20 flat plate collector manufacturers worldwide.

Vacuum tube collector manufacturers increased due to the fact that an import tax was implemented in July 2011 and made importers switch to SWH production. Almost all of the vacuum tube type systems sold in the market today are made in Turkey. Three vacuum tube manufacturers have now become part of an export industry themselves. Lara Solar, Assolar/Aslanlar Metal and Solarsan all claim to be exporting vacuum tubes to different regions worldwide, while their manufacturing capacity varies between 3 to 4 million tubes annually. The export share of solar water heaters manufactured in Turkey has been steady in recent years, varying between 10-15%. Solar thermal systems are typically marketed to the end consumer by a three-tiered chain: to wholesalers, who sell to installers, who sell to consumers. According to previous technical reports, there were over 3,000 solar water heating system installers throughout the country. Solar thermal heating supported some 20,000 direct and indirect jobs. These numbers have sharply dropped in the last five years due to shifting to PV business, which is strongly supported by the government, but no credible information exists as to 2020 employment numbers (34).

11

References

(1) *Report from the Commission to the European Parliament and the Council on the implementation of the EU Strategy on adaptation to climate change, COM(2018)0738, 12 November 2018.*

(2) *Resolution of the European Green Deal, 15 January 2020, European Parliament, 2019/2956(RSP)*

(3) *Regulation of the European Parliament and of the Council, framework for achieving climate neutrality and amending Regulation (EU) 2018/1999 (European Climate Law)*

(4) *https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/actions-being-taken-eu/just-transition-mechanism_en*

(5) *Report on Delivering the European Green Deal for Southeast Europe, 17 June 2020, CEPS Institute*

(6) *Balkan Green Energy News, Romania erases new coal-fired thermal power plants from its plans. November 23, 2020*

(7) *"The Integrated Electricity Markets in Greece and SE Europe, the Role of the International Electricity Interconnections and the Impact on Industry", IENE Study, April 2020, Working Paper No 30 - The Integrated Electricity Markets in Greece and SE Europe, the Role of the International Electricity Interconnections and the Impact on Industry.*

(8) *Erforth, Benedikt (2020): The future of European development banking: What role and place for the European Investment Bank?, Discussion Paper, No. 11/2020*

(9) *European Green Deal must be central to a resilient recovery after Covid-19, Climate Home News, https://www.climatechangenews.com/2020/04/09/european-green-deal-must-central-resilient-recovery-covid-19/.*

(10) *Dr. Fatih Birol, IEA Executive Director, Commentary "Put clean energy at the heart of stimulus plans to counter the coronavirus crisis", IEA, March 14, 2020 (www.iea.org)*

(11) *https://www.aa.com.tr/en/economy/covid-19-damages-global-renewable-supply-chain/1778533*

(12) *IRENA Report, Renewable Energy Market Analysis for SE Europe, 2019*

(13) *Decision of the Ministerial Council of the Energy Community (D/2018/2/MC – EnC)*

(14) *Renewable Energy Prospects for the European Union, IRENA Report, 2018*

(15) *https://www.euractiv.com/section/energy-environment/news/bulgaria-wants-e33-billion-to-start-implementing-the-green-deal/*

(16) *Cyprus' NECP 2021-2030*

(17) *Energy Transition of the Island of Kastellorizo, IENE study (M45), June 2019*

(18) *Electricity regulation in Romania, Delia Pachiu (Vasiliu) and Marius Nita, D&B David and Baias SCA, October 2020*

(19) *8th Turkish Wind Energy Congress, organized by the Turkish Wind Energy Association, November 2019*

(20) *Renewables 2020, Analysis and Forecast to 2025, IEA, 2020*

(21) *The role of hydropower in selected South-Eastern European countries, Dr. Jürgen Neubarth, e3 consult GmbH, 2018*

(22) *WindEurope and Eurelectric Joint workshop, Sofia, June 28, 2018*

(23) *Renewable Market Watch, 'Central East and South East Europe Solar Photovoltaic (PV) Power Market Outlook 2019-2028'. January 2020*

(24) *https://cep.org.rs/en/blogs/serbias-renewable-energy-commitments/*

(25) *IRENA, Renewable Energy Prospects for the European Union, February 2018*

(26) *Centre for Renewable Energy Sources and Savings, Role of biomass in the energy market of Western Balkans, Moldova and Ukraine, 2011*

(27) *HEINRICH BÖLL STIFTUNG BELGRADE, Western Balkans' potential for production of energy from agricultural biomass, August 2018*
(28) *IRENA, "Cost Competitive Renewable Power Generation – Potential across South East Europe", 2017*
(29) *Robert Gavriliuc, Marcel Rosca, Doina Cucueteanu, Geothermal Energy Use, Country Update for Romania, 2019*
(30) *The World Bank Group, Biomass-Based Heating in the Western Balkans – A Roadmap for Sustainable Development, October 2017*
(31) *Solar Heat Europe (ESTIF), Solar Heat Markets in Europe, November 2019*
(32) *Cyprus Association of Solar Thermal Business Owners (EBHEK), https://ebhek.org.cy/*
(33) *Annual study, Solar Heat Worldwide, Austrian research institute AEE INTEC, 2019*
(34) *Solar Heating and Cooling Programme, International Energy Agency (IEA)*

12

Energy Efficiency and Cogeneration of Heat and Power in SE Europe

Energy Efficiency and Cogeneration of Heat and Power in SE Europe

12.1 The status of Energy Efficiency in SE Europe (SEE)

12.1.1 Overview of EU Energy Efficiency Policy, until 2020

In 2007, European Union, EU, set its three key targets for 2020, as follows: (a) 20% reduction in greenhouse gas (GHG) emissions compared to 1990 levels, (b) 20% of EU's electricity to be produced by renewable energy sources (RES) and (c) 20% improvement in Energy Efficiency, which in actual numbers for the EU-28 meant Final Energy Consumption (FEC) of 1,086 Mtoe and Primary Energy Consumption (PEC) of 1,483 Mtoe.In terms of legislation, Energy Efficiency (EE) was enacted following the adoption of the so-called Energy Efficiency Directive - EED (2012/27/EU), in 2012. Also, EU requested each Member State, M-S, to set their own indicative national EE target, to prepare and publish a three-year National EE Action Plan, NEEAP, as well as an annual progress report. According to EU[1], the EU-28 and national energy efficiency targets for 2020 for SEE EU M-S, as notified by each M-S in their NEEAP (2014 & 2017) or in their annual progress reports, are shown in Table 12.1.

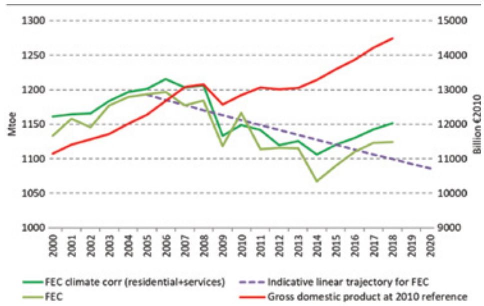
Table 12.1 **SEE EU M-S National Energy Efficiency targets for 2020 and EU-28 total**

EU Member State	Primary Final Energy Consumption in 20201 (MTOE)	
	PEC	FEC
Bulgaria	16.9	8.6
Croatia	10.7	7.0
Cyprus	2.2	1.9
Greece	24.7	18.4
Hungary	26.6	18.2
Romania	43.0	30.3
Slovenia	7.1	5.1
Sum of indicative targets SEE EU M-S	131.2	89.5
Sum of indicativ targets EU-28	1,543.1	1,095.8
EU-28 target for 2020	1,483.0	1,086.0

As shown, the sum of the indicative national targets exceeds the EU-28 target by 4% for the PEC and 0.9% for the FEC. The SEE countries contribute by ~9% of the total PEC EU-28 target and ~8% of the total FEC EU-28 target for 2020. It should be noted that from 2007 to 2014 in EU-28 there was a gradual decrease in energy consumption, mainly due to the economic recession. The scenery changed in 2014 and until 2017 with an increase of energy consumption, which was mainly due to low oil prices and to the good economic environment, in almost all EU-28, with the exemption of Greece, which was still facing a vicious economic crisis during this period. This trend was even moderated in 2018, where EU-28 PEC declined compared to 2017.

The latest report, by the EC and the European Parliament, presented "*the 2019 assessment of the progress made by M-S towards the national energy efficiency targets for 2020 and towards the implementation of the Energy Efficiency Directive as required by Article 24(3) of the Energy Efficiency Directive 2012/27/EU-COM/2020/326 final*" [2], where the EU-28 GDP versus the weather-corrected total FEC for residential and service sector, for the period 2000-2018 is shown in Figure 12.1.

Figure 12.1 **EU-28 GDP versus weather-corrected FEC, for 2000-2018** [3]



[1] https://ec.europa.eu/energy/topics/energy-efficiency/targets-directive-and-rules/eu-targets-energy-efficiency_en

[2] https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1595408944398&uri=CELEX:52020DC0326

[3] Source: calculations based on ESTAT and Odyssee data, AMECO (GDP). The weather correction factor was calculated as a proportion of heating degree days (HDD) in a given year over the average HDD between 1980 and 2004. This correction factor was applied to the energy consumption used for space heating in the residential and services sector. The calculation of the HDD follows the JRC methodology, as published by Eurostat (https://ec.europa.eu/eurostat/cache/metadata/en/nrg_chdd_esms.htm)

12

These data show that reaching the 20% target for EE in 2020 was not possible, if no additional measures and policies were to be introduced. In response, this mobilized the EC to seek new, more binding actions from its M-S. It is important to add that Eurostat, in its data released in January 2020, verified the above and showed that the PEC was 5.8% below 2020 targets for 2018, and FEC was 3.5% below those figures, thus mandating the need for more actions by the EU in the following years.

The Green Deal - Actions to move towards to a Neutral Carbon Economy

On October 11 2019, the European Commission unveiled its anticipated European Green Deal. Energy Efficiency remained a key and crucial objective of the EU's **"Green Deal"**[4] policy, as it would enable the Union to move towards a *"Climate-Neutral Economy",* by 2050. This policy is in line with the "Paris Agreement", an international treaty whose goal is to limit global warming to well below 2°C, preferably to 1.5°C, compared to pre-industrial levels and where EU played a key role for its approval and ratification by more than 160 countries.

The "Green Deal", which was officially adopted by the EU in December 2020, outlines a long list of policy initiatives, where the main ten points of the Commission's plan are presented below:

1. **'Climate-Neutral Europe'** is the overarching objective of the European Green Deal, to reach net-zero greenhouse gas emissions by 2050. That means updating the EU's climate ambition for 2030, with a 50-55% cut in GHG emissions to replace the initial 40% objective. Accordingly, the Commission reviewed all relevant EU laws and regulations, in order to align them with the new climate goals. This will start a new wave of legislative procedures including amendments of existing Directives that were recently amended as part of the Clean Energy Package, including the Renewable Energy Directive - RED (2018/2001/EU) and the Energy Efficiency Directive – EED (2018/2002/EU), but also the Emissions Trading System Directive (2018/410/EU) and others related to the Electricity Regulation (2019/943/EU), as the Electricity Directive (2019/944/EU). Already, the EU has initiated the process for a third recast of the existing Energy Performance of Buildings – EPBD (2018/844/EU). The important plan for "smart sector integration", bringing together the electricity, gas and heating sectors closer together "in one system", will be presented as a new initiative in 2021.

2. **Circular economy:** a new circular economy action plan will be part of a broader EU industrial strategy. It includes a sustainable product policy with guidelines on product production, in order to use less materials and ensure products can be reused and recycled.

3. **Building renovation:** is one of the "flagship" programmes of the Green Deal, with the key objective to double or even triple the renovation rate of buildings, which is still very low, in EU.

4. **Zero-pollution:** whether in air, soil or water, the objective is to reach a "pollution-free environment", by 2050.

5. **Ecosystems & biodiversity:** a new biodiversity strategy where Europe leads by example.

6. **Farm to fork strategy:** aiming for a "green and healthier agriculture" system.

7. **Transport:** the current objective is to reach 95 grCO_2 per km auto emissions, by 2021. Electric vehicles will be encouraged, with the main objective of deploying one (1) million public charging points across Europe, by 2025.

8. **Financial Instrument:** The Commission proposes the 'Just Transition Mechanism-JTM' to help Regions most heavily dependent on fossil fuels. The proposed €100bn financial instrument has three legs:

[4] https://ec.europa.eu/clima/policies/eu-climate-action

- A Just Transition Fund that mobilizes resources from the EU's regional policy budget;
- The "InvestEU" programme, with money coming from the European Investment Bank, EIB;
- EIB funding coming from the EU bank's own capital, where each euro spent from the fund could be complemented by €2 or €3 coming from the Regional Fund. Regions will be offered technical assistance, in order to assist them "absorb" the funds.

9. **R&D and innovation:** with a proposed budget of €100bn over the period 2021-2027, the "Horizon Europe" research and innovation Programme will also contribute to the Green Deal's initiatives.

10. **External relations:** EU diplomatic efforts will be mobilized in support of the Green Deal in order to promote a proposal for a worldwide carbon border tax.

As highlighted in the European Green Deal, Energy Efficiency is a priority, with the "***Energy Efficiency First"*** principle being applied across the EU[5]. Furthermore, in a communication paper, titled *"COM/2020/299: Powering a climate-neutral economy: An EU Strategy for Energy System Integration",* published in July 2020, the EC recognised that "the current model where energy consumption in transport, industry, gas and buildings is happening in 'silos' - each with separate value chains, rules, infrastructure, planning and operations - **cannot** deliver climate neutrality by 2050 in a cost efficient way" and a new framework should be provided for the green energy transition, with new links between sectors to be created and technological progress exploited. In other words, this means that the system should be planned and operated as a whole, linking different energy carriers, infrastructures, and consumption sectors, as this connectivity is recognised as a key factor that will provide more flexible and more efficient systems and hence reduce costs for society.

Furthermore, the above communication paper presents three main pillars to this strategy:

- First, a more **'circular' energy system**, with energy efficiency at its core. The strategy will identify concrete actions to apply the 'energy efficiency first' principle in practice and to use local energy sources more effectively in European buildings or communities. There is significant potential in the reuse of waste heat from industrial sites, data centres, or other sources, and energy produced from bio-waste or in wastewater treatment plants. The Renovation Wave is designed to play an important part of these reforms. Specifically, the Commission on 14 October 2020 published a new strategy to boost renovation called *"A Renovation Wave for Europe – Greening our buildings, creating jobs, improving lives (COM (2020)662)[6]"*, which aims to double annual energy renovation rates over the next ten years. These renovations will enhance the quality of life for people living in and using the buildings, reduce Europe's GHG emissions, and create up to 160,000 additional green jobs in the construction sector.
- Second, a greater **direct electrification** of end-use sectors, since the power sector encompasses the highest share of renewables.
- Thirdly, for those sectors where electrification is difficult, the strategy promotes **clean fuels**, including renewable hydrogen and sustainable biofuels and biogas. In due course the European Commission will propose a new classification and certification system for renewable and low-carbon fuels.

12.1.2 EU Legislation on Energy Efficiency

Energy Efficiency Directive (EED) was first published in the EU's Official Journal (OJ) on 14.12.2012, as Directive 2012/27/EU[7]. It was set up to define binding measures in order for the EU to reach its 20% energy efficiency target by 2020. As mentioned earlier, in terms of numbers this 20% means that the total EU primary energy consumption should be no

12

[5] https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=COM:2020:299:FIN
[6] https://ec.europa.eu/energy/topics/energy-efficiency/energy-efficient-buildings/renovation-wave_en
[7] https://ec.europa.eu/energy/topics/energy-efficiency/targets-directive-and-rules/energy-efficiency-directive_en?redir=1

more than 1,483 Mtoe (or 1,086 Mtoe of final energy). The EED was adopted to promote Energy Efficiency across the EU, by removing barriers and overcoming market failures that impede efficiency in energy supply and use.

The most important measures that EED introduced for improving energy efficiency in relation to the EU building sector included:

- Renovation of, at least, 3% of the area of public buildings (owned or rented) per annum
- Mandatory Energy Performance Certificates for each building, either for sale or rent.
- Minimum Energy Efficiency standards and labelling (Ecodesign) for a variety of products as appliances, lighting, heating and cooling equipment, etc.
- Preparation of national Energy Efficiency Action Plans by all EU M-S, every three years.
- National Long-Term renovation strategies for EU M-S's building stock.
- Energy Audits for large companies, at least every four years.

Article 5 of Directive 2012/27/EU states that Member States should either renovate annually 3% of the total area of buildings owned and used by central government authorities or choose an alternative approach including other cost-effective energy-saving measures in selected privately-owned public buildings (including, but not limited to, deep renovations and measures to change the behavior of users), in order to achieve by 2020 an equivalent amount of energy savings.

In 2018, the EED was amended with 2018/2002/EU[8]. The main objective was to become the key driver in achieving the efficiency target of 32.5%, compared to a "business-as-usual, BAU" scenario. In real terms, this percentage means that the EU-27 primary energy consumption should be no more than 1,128 Mtoe (or no more than 846 Mtoe of final energy), taking into consideration that the UK withdrew from the EU, on January, 31, 2020.

The major issues that this amended Directive brings for the promotion of Energy Efficiency are as follows:

- 10-yr National Energy and Climate Plan, the so-called NECP, for each M-S, outlining how they intent to tackle the EE target for 2030.
- Stronger rules on metering and billing of thermal energy, in order for consumers to have a clearer view of their consumption.
- M-S are obliged to set transparent, publicly available national rules concerning the cost of heating, cooling and hot water consumption in multi-apartment and multi-purpose buildings.
- Stronger implementation of energy audits for large consumers and companies.

In accordance with Article 7(1) of EED (2018/2002/EU) the energy savings targets to be achieved by each Member State in the period from 1 January 2021 to 31 December 2030 must be equivalent to at least 0.8 % of annual final energy consumption, averaged over the period 2016–2018.

Some specific items on building renovations were moved from EED to the most recent EPBD recast (2018/844/EU), titled *"amending Directive 2010/31/EU on the energy performance of buildings and 2012/27/EU on energy efficiency"*[9]. Since 2020, EU M-S have initiated the efforts to establish a long-term renovation strategy to support the renovation of the national stock of residential and non-residential buildings, both public and private, into a highly energy efficient and decarbonized building stock by 2050, facilitating the cost-effective transformation of existing buildings into nearly zero-energy buildings. To this end, the long-term renovation strategies include an overview of the national building stock, policies and actions to stimulate cost-effective deep renovation of buildings, policies and actions to target the worst performing buildings, split-incentive dilemmas, market failures, energy poverty and public buildings, an overview of national initiatives to promote smart technologies and skills and education in the construction and energy efficiency sectors.

[8] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv%3AOJ.L_.2018.328.01.0210.01.ENG

[9] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L0844&from=EN

The strategies must also include a roadmap with measures and measurable progress indicators, indicative milestones for 2030, 2040 and 2050, an estimate of the expected energy savings and wider benefits and the contribution of the renovation of buildings to the Union's energy efficiency target.

The EC's Regulation 2018/1999 (OJ L328), titled *"on Governance of the Energy Union and Climate Action"*[10] that is known as the "Governance Regulation", as part of the "Clean Energy for all Europeans" Package[11], was published mandating, among other fostering both efficiency in demand and supply, and improving efficiency in energy conversion, transmission and distribution.

According to the Governance Regulation, the energy and climate objectives, national targets are non-binding, with the only exceptions being the binding national targets on annual greenhouse gas emission reductions over the period from 2021 to 2030, which is determined by Regulation EU/2018/842.

Finally, the Regulation EU/2018/842[12], titled *"on binding annual greenhouse gas emission reductions by Member States from 2021 to 2030 contributing to climate action to meet commitments under the Paris Agreement and amending Regulation (EU) No 525/2013"*, that is known as the "Effort-sharing Regulation", continues the approach of annually binding national limits on greenhouse gas emissions set in Decision No 406/2009/EC (also called the Effort-sharing Decision containing the '20-20-20' targets).

12.1.3 National Energy and Climate Plans, NECP, for SE Europe countries

An important new element of the Green Deal Policy is the requirement by each EU M-S to develop its "National Long-Term Strategy" and to prepare and present a methodology of how to achieve the stated objectives.

Thus, the European Commission introduced a dynamic and transparent "Governance Process", by mobilizing all M-S, with specified policies and principles, all in an efficient and coherent manner. Part of this process is the **National Energy and Climate Plan**, NECP[13], which determines national contributions of each M-S, towards the binding EU energy-climate targets and the objectives of the Energy Union[14], over a period of ten-years, i.e. by 2030.

NECPs should cover the five dimensions of the Energy Union:

- Decarbonisation, including Renewable Energy deployment,
- Energy Efficiency,
- Energy Security,
- Internal Energy Market,
- Research, Innovation and Competitiveness.

These EU policies and strategies were also endorsed by all non-EU states in SE Europe, either in candidate or in potential candidate status, by transposing the EED to their energy legal systems. Many of these non-EU M-S are characterized as "Contracting Parties" by the Energy Community, EnC, an international organization, which brings together the EU and its neighbors in order to create an integrated pan-European energy market. This group of countries include Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Montenegro and Serbia, which all are supported by the EnC's "Energy Efficiency Coordination Group (EECG)" [15] to develop their NECP.

Based on data provided from national experts in each country, an overview of their NECPs is given below:

In **Albania**, a national working group was set-up after May 2019, led by the Ministry of Infrastructure and Energy. The first draft was developed by mid-2020. The Albanian government submitted draft chapters of its NECP to EnC, for informal review and the final draft is expected in the first quarter of 2021.

[10] https://eur-lex.europa.eu/eli/reg/2018/1999/oj
[11] https://ec.europa.eu/energy/topics/energy-strategy/clean-energy-all-europeans_en
[12] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32018R0842
[13] https://ec.europa.eu/energy/topics/energy-strategy/national-energy-climate-plans_en#final-necps
[14] https://ec.europa.eu/energy/topics/energy-strategy/energy-union_en
[15] https://www.energy-community.org/aboutus/institutions/EECG.html

In **Bosnia and Herzegovina**, a national working group was set up in May 2019, led by the Ministry of Foreign Trade and Economic Relations. The final document will be published in early 2021.

In **Kosovo**, a national working group was established in September 2018, led by the Ministry of Economic Development and Ministry of Environment and Spatial Panning. The final document will be published early in 2021. The 2020 target for the country is set in the Law on Energy Efficiency (Article 4), as a final energy cap consumption target amounting to 1,556 ktoe. The Law also introduced an energy efficiency obligation with a 0.7 % target, as well as an obligation to renovate annually 1% of central government buildings.

North Macedonia, in October 2020, became the first EnC Contracting Party submitting its draft integrated NECP to the EnC Secretariat for review and approval is expected by mid-2021. The working group which undertook this task was led by the Ministry of Environment and Physical Planning.

In **Montenegro**, a national working group was set up in November 2018, led by the Ministry of Sustainable Development and Tourism. The final document will be published early in 2021. Meanwhile, the government of Montenegro adopted the 4th Energy Efficiency Action Plan for the period 2019-2021 (4th APEE), in July 2019. For the period 2019-2021, EEAP determined an indicative target at annual level amounting to 4.16 ktoe of final energy consumption (i.e. 6.54 ktoe expressed in primary energy equivalent).

In **Serbia**, the process for developing the NECP started in 2019, but responsibilities had not yet been allocated by the Ministry of Mining and Energy. According to Energy Community's assessment, Serbia has achieved a relatively high level of implementation of the EU EE acquis.

Good practices that had been developed and introduced include:

- Introduction of an energy labeling scheme aligned with the EU practice,
- Improvement of the thermal envelope of the public and private buildings,
- Modernization of indoor and outdoor public lighting systems,
- Promotion of ESCO in the local market,
- Ongoing certification of buildings,
- Introduction of an Energy Management System (EMS-SEM) based on Japanese experience.

All results on the achievements of the 9% energy savings target by 2018 should be available in the new 4th NEEAP, which was planned to be adopted in 2019. However, the work is still ongoing.Regarding the EU M-S in the SE European region, a short presentation of their NECPs is summarized below:

For **Bulgaria**, the Ministries of Energy and Environment and Water prepared the NECP, titled "Integrated Energy and Climate Plan of the Republic of Bulgaria for the period of 2021–2030" and submitted to the EC, in late 2019. A first action was that the national legislation on EE is brought in line with EU laws. In this respect it should be noted that the primary statutory instrument for policy implementation is the Bulgarian Energy Efficiency Act (ZEE).

According to the requirements laid down in the ZEE and the provisions of EED and EPBD the following strategic legal documents have been developed and are implemented:

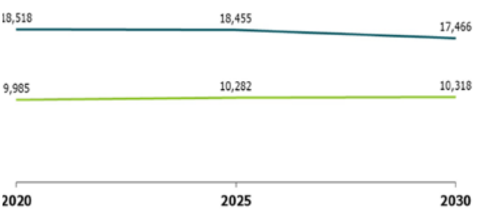
- National Energy Efficiency Action Plan 2014—2020;
- National Plan for nearly zero-energy buildings 2015—2020;
- National plan for improving the energy performance of heated and/or cooled State-owned buildings occupied by public administration;
- National long-term programme to promote investments for improving the energy performance of public and private national residential and commercial building stock.

According to NECP, Bulgaria's primary energy efficiency priorities and policy objectives are targeting for:

- achieving energy savings of 8,325 GWh, by 2020;
- achieving annual energy savings of 1.5 % by volume of energy sales;
- taking action to improve the energy performance of at least 5 % of the total gross floor area of all heated and/or cooled public buildings used by civil services;
- increasing the number of nearly zero-energy buildings;
- ensuring that secure and affordable energy is available to all consumers, which will improve the living conditions in Bulgaria;
- minimising the adverse effects of energy use on human health and the environment;
- increasing the competitiveness of the Bulgarian economy.

By 2030, Bulgaria plans to achieve a decrease of primary energy consumption by 27.89 %, a decrease by 31.67 % of the final energy consumption, compared to the reference scenario. The annual trend of energy consumption towards 2030, is illustrated in Figure 12.2.

Figure 12.2 **Primary and final energy consumption (ktoe) trajectory in Bulgaria**



Primary (blue) and final (green) energy consumption (ktoe) trends in Bulgaria.

According to the NECP, Bulgarian strategy for achieving indicative milestones for 2030, 2040 and 2050, includes:

- indicative interim targets for 2030, 2040 and 2050,
- indicative description of financial resources to support strategy implementation, and
- effective mechanisms for promoting investments in building renovation, all in accordance to Article 2a of the EPBD (2018/844/EU).

To help achieve the national energy efficiency target by 31 December 2030, an energy savings obligation scheme and alternative measures will be established to ensure the achievement of the target for energy savings in final energy consumption.

For **Croatia**, energy efficiency is regulated by a series of legal Acts, including the Energy Efficiency Act (OG Nos. 127/14, 116/18), the Building Act (OG Nos. 153/13, 20/17, 39/19), the Act on Protection against Light Pollution (OG No. 14/19) and by-laws that follow from these Acts. The key document for the EE dimension is the *"Long-Term Strategy to Encourage Investment in the Renovation of the National Building Stock of the Republic of Croatia by 2050"*, which promotes the need to invest in the building stock. The current energy renovation rate of 0.7% per year will gradually rise to 3% over the 2021-2030 period, with a 10-year average rate of 1.6%. An important element is the introduction of additional measurable indicators of energy renovation of buildings, which will strengthen the process of conversion of the stock into nearly zero-energy buildings. The indicative national energy targets for 2030 is given in Table 12.2.

Table 12.2 **Indicative national energy targets in 2030, for Croatia**

	ktoe
Primary energy consumption	344.38
Final energy consumption	286.91

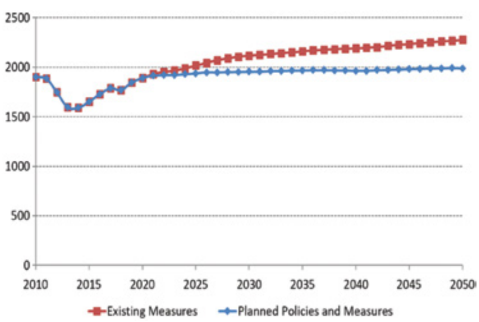
In the transport sector, the share of alternative fuel vehicles is still relatively small (less than 3%). In December 2016, Croatia passed the *Act on the Deployment of Alternative Fuels Infrastructure* (OG No. 120/2016) transposing into national law the provisions of relevant EU Directives as 2014/94/EU on the deployment of alternative fuels infrastructure. A joint framework of measures for market development regarding alternative fuels in the transport sector and for deployment of adequate infrastructure is defined in the *National Policy Framework for Deployment of Alternative Fuel Infrastructure of the Republic of Croatia*, which was adopted in Croatia in 2017, which it sets minimum targets for building alternative fuels infrastructure, including filling stations, joint technical specifications for filling and supply stations, user notification requirements, as well as measures needed to achieve national targets.

In **Cyprus**, EE is a key horizontal priority in NECP. In particular, the following targets for EE are set by 2030:

- 21% reduction in non-ETS greenhouse gas emissions compared to 2005.
- National indicative key targets set for energy efficiency: final energy consumption of 2.0 Mtoe and primary energy consumption of 2.4 Mtoe in 2030.

Accordingly, the national obligatory target is set at achieving cumulative final energy savings of 243.04 ktoe during 2021-2030. These targets are expected to be achieved in the context of the overall energy planning of the country as illustrated in Figure 12.3.

Figure 12.3 **Forecast of final energy consumption in Cyprus (ktoe)**



The improvement of EE in all sectors has been examined in the framework of *"the Energy Efficiency first"* principle. The policies and measures set for improving EE contribute significantly to reducing GHG emissions. Accordingly, Cyprus strengthened the focus on energy efficiency in the transport sector by increasing the span of measures related to this sector, considering that it would represent half of the energy consumed in the country in 2030.

Also, a national strategy for energy efficiency in heating and cooling will be set, by implementing steps and milestones for the share of renewable energy sources in heating and cooling sector.

In **Greece**, the initial draft NECP was prepared in January 2019. However, this coincided with the time of governmental change in the country, so the plan was updated setting much more ambitious objectives and was released in January 2020. Specifically, the plan sets a quantitative target for the final energy consumption in 2030 to be lower than that recorded in 2017. Therefore, the NECP's objective is fully compatible with the relevant EU targets. Attaining this ambitious objective will strengthen the competitiveness of the Greek economy and further shield consumers. Specifically, the NECP proposes a set of energy efficiency improvement measures, including the most ambitious ones relating to buildings and transport, as follows:

- final total energy consumption not to exceed 16.5 Mtoe in 2030,
- primary energy consumption not to exceed 21.0 Mtoe in 2030,
- to attain cumulative energy savings (buildings + transport) of 7.3Mtoe in the period 2021-2030,
- building renovations to cover, on an annual basis, 3% of the total heated floor area of central government buildings, by 2030.

To attain those objectives, specific measures are being planned for buildings with a view of implementing an ambitious plan for the renovation and improvement of the energy performance of the public buildings stock through the participation of ESCOs and the renewal of end-of-lifecycle buildings. Targeted incentives are also being prepared for promoting energy efficiency measures in private buildings, by adopting an ambitious strategy for renovating the building stock in order to renovate 12-15% of the buildings by 2030. In addition, measures are being planned for the industrial and transport sectors, focusing on specific energy consumptions and uses for which energy efficiency improvement and energy savings actions with a high cost-effectiveness can be implemented.

Also, a change to the urban mobility model is foreseen aiming to curtailment of the use of private vehicles and the increase of 'soft' forms of transport. Special measures and incentives are also being planned for the bioclimatic upgrade of urban public spaces in order to reduce the urban heat island effect by 20% by 2030.

Another priority aims to the optimal use of available public and private financial instruments. The goal is to ensure maximum benefits for final consumers, taking into account the specific needs of each end user and the characteristics of the optimum energy measures.

For **Hungary**, the main target of its NECP is to ensure that the country's final energy consumption in 2030 does not exceed 18.75 Mtoe that is actually the same value as in 2005. Any amounts of energy exceeding the 2005 level must be exclusively derived from carbon neutral energy resources. Hungary aims to ensure that GDP growth exceeds the rate of the increase in energy consumption. The cumulative end-use energy saving obligation for the 2014–2020 period amounts to 4 Mtoe and for the 2021–2030 period at 7.9 Mtoe. This can be achieved with steady annual savings of 0.17 Mtoe or an annual rate of 0.8 % and policy measures spanning over the entire period, compared to the base case of business as usual. In 2018, Hungary's primary energy consumption was 24.5 Mtoe, while the final energy consumption reached 17.9 Mtoe. Final energy consumption in 2018 was below the target of the 2005 level by around 0.29 Mtoe, while the Hungarian GDP grew on average by 1.5% annually since 2005.

Hungarian industrial energy consumption has been increasing each year since 2009. In 2013, consumption reached the level of 2005, and in 2017 it even exceeded the level by around 18%. As a positive development we should observe that energy consumption in transport fell short of the 2005 level and energy consumption in the services sector and in households significantly declined over the years since 2005. Transport, passenger and freight transport sectors show a decline in energy consumption; the situation has worsened since 2013, as the period between 2009 and 2013 is essentially characterized by stagnation in carriage of goods and a fall in consumption.

Hungarian households have been consuming more energy since 2014. In 2015, the energy use intensity of residential buildings was 243.1 kWh/m^2, which exceeded the EU-28 average by 37.5 % after adjustment for climate differences. Furthermore, no significant progress has been made compared to the level in 2005 (245.4 kWh/m^2). The final energy consumption per household also reflects a similar trend, decreasing from 1.54 to 1.24 toe/household, between 2010 and 2014, while on average increasing by 0.177 toe/household between 2015 and 2017. In order to tackle this serious problem, the Hungarian NECP is planning to introduce cost-effective incentives and investments in order to promote EE in all these sectors.

In **Romania**, in the context of the additional measures and policies foreseen in the NECP, the target for the primary energy consumption in 2030 is 32.3 Mtoe achieving a 45.1 % decrease compared to the PRIMES 2007 scenario, which shows 58.7 Mtoe. Similarly, the target for the final energy consumption is 25.7 Mtoe by 2030 compared to 43.2 Mtoe (-40,4%).

According to the NECP, trajectories of primary and final energy consumption indicate a slower decrease in the period 2020-2025, with an estimated 2.4 % decrease for primary consumption and a 2.9 % decrease for final consumption. This trajectory indicates a savings increase from 38.4 % in 2025 to 45.1 % in 2030 for primary energy consumption, and from 34.0 % to 40.4 % for final energy consumption in the same period, in relation to the baseline scenario.

In **Slovenia**, the goal is to improve EE by 2030, by at least 35%, by systematic implementation of designated policies and adopted measures. The final energy consumption in 2030 will not exceed 4,717 ktoe and the primary energy consumption will be less than 6,356 ktoe.

The key targets for promoting Energy Efficiency in Slovenia include:

- improve energy and material efficiency in all sectors, as the first and key measure for the transition to a climate-neutral society,
- improve energy efficiency by 2030 by at least 35% compared to the 2007 baseline scenario (in line with the EED),
- ensure the systematic implementation of policies and measures adopted, so that final energy consumption will not exceed 4,717 ktoe,
- reduce final energy use in buildings by 20% by 2030 compared to 2005 and ensure a reduction of GHG emissions in buildings by at least 70% by 2030 compared to 2005,
- speed up the implementation of programmes for informing, raising awareness and training of different target groups on the benefits and practical aspects of the development and use of Energy Efficient technologies and the use of renewables.

Similar information for the two other states in the region, i.e. Israel and Turkey, are presented below.

In **Israel**, a new program, based on the *"Guidance for Energy Efficiency Action Plans under EU Directive 2012/27/EU"*, was approved by governmental Decision 3269, at the end of 2017. The aim is to reach, by 2030, an electricity consumption target of 80 TWh compared to the "business-as-usual" scenario, by which electricity generation in Israel would reach 96 TWh. The program consists of several supportive tools, taking into account that Israel has a fully liberalized energy market:

- Financial: grants, and subsidies in the form of loans and tax benefits,
- Regulation: energy labelling and minimum energy performance standard,
- Public awareness.

Total energy consumption was divided for the different end-use sectors (i.e., residential, commercial and public, industrial and water, transportation, agriculture and the Palestinian Authority), with each sector being examined for its inherent potential for energy savings, suitable policy tools, costs and expected savings.

The building sector is split between residential, commercial & public, where the main attention is given to energy efficiency measures in HVAC systems, all types of lighting (internal and street lighting), appliances and solar water heaters.

In **Turkey,** the 2017-2023 NEEAP was developed in compliance with EED (2012/27/EU) and published in 2017. It aims towards effective implementation and monitoring of the national energy efficiency actions with 23.9 Mtoe cumulative reduction of primary energy consumption in the period of 2017-2023. According to the Ministry of Energy and Natural Resources this means decreasing the primary energy consumption in Turkey by 14% in 2023, compared to the base case scenario. The plan aims to reduce Turkey's energy intensity by 20%, by 2023 compared to 2011.

12.1.4 Incentives for the promotion of Energy Efficiency in SE Europe

For both Albania and Bosnia and Herzegovina, all incentives for the promotion of EE projects are coming either from EU or international financial institutions (IFIs) funding. These are discussed analytically in a later section of this chapter.

For **Bulgaria**, incentives for EE measures and mainly for increasing the share of household gasification across the country, are foreseen from the Ministry of Energy by implementing a project, titled *'Energy efficiency measures at the level of final consumers of natural gas'* (DESIREE) providing a grant assistance, of €10.9m from the Kozloduy International Decommissioning Support Funds (KIDSF). The program aims to encourage gasification of approximately 10,000 households, in order to connect them to the existing central gas distribution network. The main incentives include: pay for a fixed fee of 30% of the eligible investment cost, and 100 % of the connection change, up to €1,000 per household for systems with high-efficiency boilers and up to €1,200 per household for condensing boiler systems.

For **Croatia,** all financial support measures for EE in residential and industrial sectors for the period 2021-2030 that are envisaged by the NECP, come from either national funds from emission allowances auctions, revenues from the Environmental Protection or Energy Efficiency fund or from other funds, with a deadline that all measures to be implemented until 2030. In particular, the Programme for Energy Renovation of Family Houses, 2014-2020, was financed by national funds raised from auctions through the Environmental Protection and Energy Efficiency Fund and the European Regional Development Fund (ERDF), available under O.P. Carbon Capture (OPCC), amount to €26.7m, (HRK 200m). However, due to the complex procedures involved, these funds are not expected to be utilized for energy renovation of family houses. The plan is to reallocate these funds for energy renovation of public and apartment buildings, whereas from 2019 onwards this Programme is co-financed by the funds collected from the sale of emission allowances in auctions, through the Environmental Protection and Energy Efficiency Fund (EPEEF). In the public sector, ERDF funds through the OPCC, the amount of €211m which is available for energy renovation of public sector buildings. So far, around €197.3m (HRK 1.499b) have been awarded for energy renovation of 866 buildings; the projects within this programme are expected to be completed, by the end of 2023. Also foreseen are EE loans for public buildings coming from international funds in the order of €25m (HRK 190m).

For **Cyprus**, €48.27m have been secured through the European and Structural Funds 2014-2020, for grant schemes and projects for energy efficiency investments in private and public buildings. The amount of €8.7m will be allocated for improving the energy efficiency of buildings used by SMEs, €18.4m for energy retrofits in households, €20m for improving the energy efficiency in central government public buildings and €1.17m for pilot projects of combined heat and power generation in public and semi-public buildings.

The following projects under this package may be extended up to 2023:

(a) the operation of a support scheme for the installation of cogeneration of heat and power (CHP) systems, fueled by biomass/biogas for the production of electricity for self-consumption and support a scheme based on net-billing principle for the installation of high efficiency CHP (HECHP), with a capacity up to 5MW; (b) The support scheme *"Solar Energy for All"* covers the following costs: for onsite production and consumption of RES for self-use which provides: (i) the installation of net-metering PV systems with capacity up to 10 kW connected to the grid for all consumers (residential and non-residential), and (ii) the self-generation systems with capacity up to 10MW for commercial and industrial consumers; (c) A support scheme for the replacement of old-type solar domestic hot water heating systems; (d) A grant scheme for the insulation of roofs in the residential sector; (e) A grant scheme for conducting energy audits in SMEs; (f) A decision for the establishment of a new energy efficiency revolving fund /soft loan financing instrument to promote investments in the fields of EE and RES, targeting small and medium-sized enterprises, public bodies and households; (g) Private financing institutions to offer financing for EE bucked investments, such as energy loans for thermal insulation and energy efficiency upgrade of buildings; (h) Targeted energy efficiency measures/investments in public buildings; (i) Establishment of an energy efficiency network with voluntary agreements with businesses; (j) Financing measures for energy efficiency investments in the tourist sector; (k) Financing measures in agriculture and transportation; (l) Replacement of all old-type street lamps/lighting fixtures in roads with new, more efficient ones.

For **Greece**, the new proposed financing instruments to be implemented will contribute towards the effective use of potentially available resources for improving EE and reducing CO_2 emissions.

These include mobilizing additional sources of funding from the Greek financial sector, the envisaged National Energy Efficiency Fund or from the Structural Funds in the new planning period, 2021-2027. Regarding the envisaged National Energy Efficiency Fund (NEEF) this is expected to provide the basis for the development of new financing tools, aiming to support programmes and other measures for energy efficiency improvement and help develop the energy services market.

The Fund may serve as both "lending fund" and "guarantee fund". Initially, part of the capital of the structural funds is expected to be transferred to the NEEF, in order to support EE projects by considering the use of a "revolving capital" mechanism. The NEEF's main activity is to refinance loans from available funds from which loans are granted and in the context of which loan repayments are made and re-leased. Using this mechanism, the NEEF can grant favorable loans to public authorities or to ESCOs in order to implement energy saving projects. Also, from the NEEF, with the intention to make EE investments more attractive, available funds may be used to subsidize part of the cost of the project or to further improve the conditions for financing loans to ESCOs and/or public authorities. Finally, advisory services are expected to be funded, as they will be required to identify potential savings and monitor projects in order to ensure credible results.

The programme *"EXOIKONOMO - AUTONOMO"* (Save-Autonomize), an EU co-funded program through the Greek Operational Program (OP), provides funding for the implementation of EE interventions, aimed at saving energy in the residential building sector, reducing energy consumption and consequently the energy costs of households, with particular concern for low and middle incomes. The program aims not only at energy saving, but also at the energy independence of households, with new incentives and interventions that encourage the production and storage of energy from RES and the installation of "smart" energy management systems (net-metering).

It is a program fully adapted to the requirements of the NECP, but also designed to meet European Union guidelines on climate change policies. The most recent financing schemes of the programme include:

- Phase A' in 2018 had a budget of €502.99m, where €465.66m was covered from O.P for Greece and €37.33m from the Regional O.P.
- Phase B' in 2019 had a budget of €778.01m, where €602.36m came from O.P for Greece and €60.97m from the Regional O.P. and €80.68m from the state budget.
- Phase C' is expected in early 2021.

The main conclusion from these two phases of the program was that it performed successfully, but, some deficiencies were detected, as delays mainly due to bureaucracy. Future phases were redesigned to overcome the problem of overflowed electronic platform in short-time period by potential appliers to the Programme.

For **Hungary**, programs for energy efficiency are available among different programs of the EU-funded Operational Program, designed for the country, as well as from dedicated funds assigned via the Environmental and Energy Efficiency O.P. (KEHOP), the Economic Development and Innovation Operational Program (GINOP), the territorial and settlement development OP, TOP and the Competitive Central-Hungary O.P. (VEKOP). Actions within the KEHOP include: Designing an energy development base for public buildings or the Energy Efficiency investments of budgetary institutions. The GINOP program aims towards: credit provision for increasing energy efficiency and renewable energy use in residential buildings, or provide support for building energetics developments aiming at increasing renewable energy use and energy efficiency especially for SMEs.

The government program titled *"Warmth at Home"* is aiming to support physical persons. In recent years, the focus has been on building renovations to improve their energy performance, campaigns for replacing household appliances and the modernization of heat generation equipment.

Additionally, based on corporate tax law, there is tax reduction available for companies' investments aiming at increasing the energy efficiency of their operations.

For **Israel**, a specialized fund for EE projects has been established, with a budget of $145 million. The funds are used for qualified energy saving projects and they are distributed using tender processes, such as loans.

For **Montenegro**, the Ministry of Economy has implemented a number of energy efficiency projects in order to improve EE in buildings, jointly with international and local partners, including:

- MEEP - Montenegrin Energy Efficiency Project,
- EEPPB - Energy Efficiency Program in Public Buildings,
- MONTESOL- Interest-free credit line for installation of solar-thermal systems for households,
- ENERGY WOOD - Interest-free credit line for installation of heating systems on modern biomass fuels (pellets, briquettes) for households,
- SOLARNI KATUNI - Project related to installation of PV solar systems in summer pasture lands.

The Ministry of Economy has also launched the *"Energy Efficient Home"* program aimed at reducing heating costs and increasing household comfort, achieving a significant reduction in CO_2 emissions in the household sector, and developing a market for biomass heating systems in Montenegro. In order to reduce pollution in the Municipality of Pljevlja, co-financing of pellet procurement is carried out for citizens, who already have pellet heating.

Serbia, in line with the Law on Efficient Use of Energy provisions, in 2017, introduced an Energy Management System (EMS-SEM) project, which was supported by Japan International Cooperation Agency (JICA), and financed by the Global Environment Fund and the United Nations Development Programme (UNDP). EMS covers approximately 70% of final energy consumption of the country and targets sectors for energy audits, performed by licensed energy auditors – 180 in total, and include: (a) municipalities over 20,000 inhabitants, a total of 79 cities and towns, (b) commercial buildings with annual consumption more than 1000 toe, in total 8 enterprises mainly in trade, (c) industrial companies with annual consumption more than 2500 toe, in total 72 industrial facilities and (d) all government facilities with working space more than 2000 m^2.

By 2014, the Serbian government had introduced financing instruments for EE projects, by allocating €2.6m from the State Budget Fund with eleven (11) municipalities having used it for improving heating facilities, while, in 2016, the Fund had assets of €1.5m distributed to fifteen (15) communities. The overall results of the budgetary fund for 4 years was distributed as an investment of €3.5m for 39 projects (27 completed by 2019) with 30% contribution of municipalities and expected energy savings of about 808 toe and annual reduction of CO_2 emissions by 4150 t/year. This state financing support for EE was improved in 2018, as the government introduced a surcharge for all energy sources (electricity, oil products, natural gas), namely ~0.012 c€/kWh for electricity, ~0.012 c€/lt for oil products, and ~0.012 c€/m^3 for natural gas and the expected revenues from this surcharge is expected to about 9 mil €/year. The Ministry for Mining and Energy has identified 150 new projects which had been realized until 2018, with total energy savings of 17 ktoe. For 2020, Serbia had an energy efficiency target linked to the energy renovation of 1% of central government buildings (i.e. 57 buildings with about 405.000 m^2) and a 0.7% target under the energy efficiency obligation scheme.

For **Slovenia**, the strategy for the improvement of energy efficiency in buildings has been set in NECP and also in the new Long-Term Strategy for Mobilizing Investments in the Energy renovation of buildings. The most important measure for households promoting EE improvement in buildings is financial support in the form of subsidies or soft loans provided by the Ecofund. Funds are available for adding thermal insulation on building façades or roofs, installing new energy efficient windows with wooden frames, installing mechanical ventilation systems with heat recuperation, installing new wood biomass boilers, heat pumps or solar collectors. If a combination of different measures is applied, then a higher subsidy is available. Subsidies are also available for building or purchasing of a passive house or a flat in a passive building. A special program has been designed for socially weak households, where 100% subsidy for energy efficiency measures in multifamily houses or substitution of old wood boilers is available. In cooperation with social centers a package for reducing energy poverty is also available for them, providing expert counseling on reducing energy use. Funds for the operation of the Ecofund come from the government's own funds, by means of contributions paid per energy use in order to increase energy efficiency and from 2014 onwards from the Climate Fund. In 2018 the Ecofund provided subsidies of approx. €26.2m. An important measure which supports funding is the energy consulting network for citizens (ENSVET) which provides free advice on the implementation of energy efficiency measures to households with the Ecofund funding the operation of the network. According to the findings of a study by the ENSVET group, in the future, special attention must be given to the support of energy efficiency measures in buildings where old people live and to address non-economic barriers in multifamily houses, like reaching agreement on renovation, relations between tenants and owners (new instruments to be prepared for multifamily houses i.e. guaranty schemes). For buildings in the public sector, it is mandatory to implement an energy management system. Funds for public buildings are available as subsidies that are provided by Ecofund. Cohesion Fund is an important source of funding for this sector.

In 2019, some €21.1m became available from the Ministry of Infrastructure for public building renovation, while the Ecofund had planned €1.5m in 2019-2020. Measures are being implemented also through large energy suppliers' obligation scheme and energy contracting. Another significant action is the training of employees who are going to be involved in the preparation and overseeing of EE projects, with technical support received from the ELENA project for the public sector. Slovenia has set up a "project-office" for the renovation of public buildings providing support to ministries and other public sector entities when preparing projects. Energy contracting is an important instrument for the implementation of EE measures in the public sector. During 2016-2018, a total of 32 projects were approved. This instrument will be enhanced further through the provision of new financial products to ESCOs and other support measures. The intent is to use it in other types of buildings, in accordance with a new regulation based on the Long-Term Strategy for Mobilizing Investments in the Energy Renovation of buildings that will be published in late 2021.

In **Turkey,** three main types of incentives for EE projects are in force, including:

1. Incentive-based initiatives in the building sector, which are planned or are in place. Since 2009, the Ministry of Energy and Natural Resources is supporting energy efficiency projects with incentives and the Ministry of Environment and Urbanization helps to rebuild the old building stock, according the new regulations promoting EE.
2. Energy Efficiency Improvement Project (EEIP). This incentive is designed for industrial companies, with a minimum of 1,000 toe of annual energy consumption, which can apply and receive up to 30% grant for an EEIP, or less than €100,000 (approx.1 million TL) investment.
3. Voluntary Agreements Program (VAPs). Eligible for such support are companies with a minimum of 1,000 toe of annual energy consumption, targeting a minimum of 10% decrease in energy intensity over a three-year period. Companies meeting the agreed target may receive up to 20% of the energy costs, during the first year up to €20,000 (200,000 TL). Companies may apply and receive grants for the EEIP implementation and the Voluntary Agreements at the same time.

12.1.5 EU- and IFI-funded Energy Efficiency Programmes in SE European countries

This section analyzes the EU and IFIs- funded programmes for SE European states; with the *"EU candidate"* and the "EU potential candidate" status. It can be said that this assistance is similar to the one provided by EU to many of its M-S, which require financial/technical assistance for EE projects and programmes, mainly through their Operational Programmes and Structural Funds.

In **Albania**, as reported by the local Agency for Energy Efficiency (AEE), the EU- and IFI-funded EE programs during the period 2017-2019, are mainly targeting the building sector including:

1. A project, titled *"Energy Auditing of Public Buildings"* that is financed by the state budget, aiming to create a public building stock inventory, to be located on the AEE's server, by naming and codifying them in the national electronic register, as well as to audit the entire stock of buildings in the next three years.
2. A project financed by KfW Development Bank, *"Promotion of Renewable Energies and Energy Efficiency"* that aims for EE renovation of dormitories in Students City No. 1 and Student City No. 2, targeting an energy performance of 75 kWh/m^2 per year.
3. The project *"Development of a Financing Mechanism for Energy Efficient Public Buildings in Albania"* that aims to inform and facilitate decision-making for sustainable financing mechanisms for EE in the public building sector.
4. The project *"Smart Energy in Municipalities"* that is financed by the Swiss Embassy in Tirana, which aims to support selected Albanian municipalities to manage energy in a sustainable manner and to implement the national energy policy at local level.
5. The project *"Energy Management in Municipalities"* that is financed by Germany's GIZ, which is concerned with the planning, prioritizing and implementing selective energy efficiency measures in 12 municipalities.
6. The Regional Program *"ORF Energy Efficiency"* that is financed by Germany's GIZ, which aims to support Albania to take advantage of regional networks for the implementation of EU standards in the field of climate protection.

In **Bosnia and Herzegovina**, according to Energy Community Secretariat, the EU- and IFI-funded EE programs are mainly designed for the buildings sector. Many of their financial products are based on the availability of dedicated credit lines through international financial institutions and development banks, supported by EU grant funding for both technical assistance and financial incentives. Some of these projects include the:

- Regional Energy Efficiency Programme (REEP and REEP Plus) that provide technical assistance and investment grants from the European Bank for Reconstruction and Development (EBRD) and the EU,
- Green Economy Financing Facility (GEFF) that provides technical assistance and investment grants from the EBRD,
- Green for Growth Fund (GGF) that provides technical assistance and investment grants from the European Investment Bank (EIB) and KfW Development Bank.

In **Kosovo**, part of a threshold program agreement between the United States of America, acting through the Millennium Challenge Corporation (MCC) and the government of Kosovo, which entered into force in September 2017, is the program titled *"Procurement of implementer for pilot incentives for EE"*. Based on the Threshold Program Agreement, the government of Kosovo founded the Millennium Foundation Kosovo (MFK), as the implementing entity of the Threshold Program. The Threshold Program addresses two key constraints related to Kosovo's economic growth: (a) an unreliable electricity supply; and (b) real and perceived weakness as in the rule of law, government accountability and transparency.

In order to address these key constraints, the Threshold Program comprises two projects – the Reliable Energy Landscape Project (RELP) and the Transparent and Accountable Governance Project (TAGP). The overarching objective of the RELP is to reduce the gap between energy demand and supply, by lowering energy use through pilot household related investments in energy efficiency, switching to cost-effective non-electricity sources of heating, and also reducing barriers to independent power producer entrants to the market. The Pilot Incentives for the Energy Efficiency (PIEE) project under the RELP is expected to contribute towards the RELP objective by increasing consumer awareness of energy saving measures and their benefits, as well as by enabling lower income households to overcome the lack of ability to pay for them through the provision of incentives.

The Project, financed by the MCC and managed by the MFK, shall be carried out by a consortium of the GFA Consulting Group GmbH and HPC AG. The Project started on 23rd of September 2019, with a planned duration of 24 months, but with a possible extension, due to COVID-pandemic caused delays.

In **North Macedonia**, Energy Efficiency Programmes funded by the EU or other IFIs are focusing on the building sector as presented in the 3rd Annual Report, issued in June 2019[16]. The currently ongoing programmes include the following:

- A World Bank Public Sector Energy Efficiency Project which includes a €25m loan from the International Bank for Reconstruction and Development (IBRD) to reduce energy consumption in public sector buildings and support the establishment and operational of a sustainable financing mechanism;
- An EBRD project through which five municipalities will conclude public private partnerships (PPPs) for providing public lighting services;
- Technical assistance funded through GIZ for the operational of the Monitoring and Verification Platform (MVP). The MVP platform will enable good communication and coordination between national and local levels;
- A Residential Energy Efficiency project in the Western Balkans (WB) as part of the Economic Resilience Initiative-Infrastructure Technical Assistance (ERI-ITA) project, funded by EIB;
- A Cooling/Heating project financed by Horizon 2020, a Framework programme for research and innovation 2014-2020. The project promotes the implementation of "small modular renewable heating and cooling grids" for communities in SEE.

For the coming years North Macedonia is planning the following EE projects:

- An EU financed Instrument for Pre-Accession Assistance (IPA2) Grant scheme for implementing pilot measures for climate change and energy efficiency with emphasis on public buildings is under preparation, through which € 4 million will be provided from EU IPA funds;
- Negotiations are under way for launching a €25m programme, through a Loan Agreement for the Public Sector Energy Efficiency Project, which is part of the new four-year Strategy of EBRD – World Bank partnership for the period 2019-2023;
- EE Renovation of State Student Dormitories Project to be implemented by 2024. The total investment value of the project amounts to approximately €25m, to be provided through a €20m loan from Germany, via KfW, and to be supplemented by a grant from EU of €4.785m.

In **Montenegro**, the EE programs currently ongoing include the following:

1. *«Energy Efficient Home»* an interest-free loan for installing heating systems using biomass and performing works to improve the energy performance of the building envelope. In 2018, the Ministry of Economy provided €120,000 for the implementation of the program Energy Efficient Home, which was initiated in October 2018. This program is a

[16] https://www.energy-community.org/implementation/North_Macedonia/reporting.html

continuation of a similar one called «Energy Wood» which has been expanded by other EE measures. The goal of the «Energy Efficient Home» program is to offer households in Montenegro, through interest-free loans (up to €8,000, with a repayment period of up to 6 years), the opportunity to achieve economic and energy savings by using biomass heating systems and also help improve the energy performance of the building envelope (i.e. provide façade walls thermal insulation in residential buildings). Within the first phase of this project, €33,339 was spent for the implementation of EE measures in 93 households in Montenegro. Local governments have also established supporting programs for citizens, providing interest free loans in cooperation with commercial banks, in order to implement EE measures in their households (e.g. Municipality of Tivat).

Future activities on EE programs, in Montenegro include the following:

- Continuation of the program «Energy Efficient Home» over the next period. The allocated budget in 2019 was approximately €100,000 for the implementation and interest rate subsidy through commercial banks. The plan for the future implementation of the program will take into account the following:
  i. In case of the Green Economy Financing Facility (GEFF) Residential project, will modify the «Energy Efficient Home» program, so that there is no overlap regarding the implementation of EE measures;
  ii. The implementation of support programs aimed at improving energy efficiency in households and other sectors of final energy consumption should be gradually transferred to the EcoFund.
- Launch of the GEFF-Residential project, where through EU support, Western Balkan countries have received funds to support the household sector for the implementation of energy efficiency measures through the Western Balkans GEFF-Residential project, which is coordinated by EBRD. In order to implement this project in Montenegro, it is necessary that EBRD establishes cooperation with commercial banks, which will be obliged to establish dedicated credit lines for energy efficiency applications. In the event that citizens realize energy efficiency measures by using funds from these credit lines, they acquire the right to subsidies, from the allocated EU funds, corresponding to 15-30% of the amount of the investment.

In **Serbia,** some successful examples of EE projects that have been carried out with the assistance of EU and other IFIs, include:

- The German Development Bank (KfW), has launched two subsidized loan programs with technical assistance, the *"4E Facility"* and the "Eco-loans" for EE improvement in public and private legal entities. The total amount of €120m was disbursed to local commercial banks to finance these investments. A typical "good practice" example of this type of financial support is the project *"Rehabilitation of the District Heating System"*, which started in 2012 and ended in 2019, during which a total of 68 projects, worth over €52m were completed, financed largely from a KfW soft loan (€45m), while the remaining funds were contributed by the state budget.
- Improving EE of public facilities in four cities in Serbia was implemented through the project *"Energy Efficiency and Energy Management in Municipalities"* (PEEUEO), a collaboration between the Swiss and Serbian governments. The project covers 26 buildings – 17 primary schools, 6 kindergartens, 1 high school and 2 health facilities. The project's budget was €9.2m (CHF10m), of which the Swiss government financed 88% of the total budget and the rest was contributed by the Serbian government.
- The ongoing program for the renovations of central government buildings is financially secured by the state fund for EE and supported with a €45m investment loan by the Council of European Development Bank. Major financial institutions like the World Band, EBRD, EIB, and KfW are becoming increasingly engaged in providing affordable lending terms to large scale energy efficiency schemes.

In **Turkey,** the main instrument for the promotion of EE is the Turkish Residential Energy Efficiency Financing Facility (TuREEFF). The programme developed by EBRD and supported by the Clean Technology Fund (CTF) and the EU, aims to provide finance to residential property owners and investors who want to invest in EE projects in their buildings. Launched in 2015, TuREEFF is combining $270m by EBRD and CTF loans to promote a transition to Energy Efficiency mortages by the local banks. The loan facility is complemented by an EU funded technical assistance program. The interested parties receive support from an expert team to develop Energy Efficiency projects and to prepare loan applications free of charge. Financing and technical assistance are available via four participated local financial institutions as Şekerbank, Işbank, GarantiBBVA and YapıKredi. Until 2019 TuREEFF supported approximately 4500 projects, achieving 29.3 GWh/year primary energy and 7,393 t/year carbon savings[17].

Another programme is the *"Energy Efficiency in Public Buildings in Turkey"* that was launched under the German Climate Technology Initiative (DKTI). The project (2014 and 2020 aimed to improve the legal, technical and administrative framework conditions for energy efficiency in public buildings in order to reduce their energy use and to comply more closely with EU energy efficiency standards. The project is commissioned by the Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) of Germany. From the Turkish side, the Ministry of Environment and Urbanisation (MEU) is the lead executing agency. Since the beginning of the programme a large number of engineers and architects were educated in Train-the-Trainer programmes on Energy Performance Certificates in Turkey and its newly developed software. In this context several energy audits in public buildings with a focus on public schools were carried out. An innovative combined energy efficiency and earthquake-safety retrofit design for a public school was carried out. An energy efficiency data management system (DMS) for public buildings in Turkey is currently under implementation.

An Energy Efficiency Technology Atlas on energy efficiency products and services in various sectors in Turkey was prepared and launched with the support of GIZ and DKTI Programme for EE in Public Buildings in Turkey.

Finally, a recent project titled *"Technical Assistance for Renewable Energy and Energy Efficiency Support for the Municipalities and Universities – YEVDES"*, was initiated with EU funds[18]. The project has a budget of €4.5m and was launched in March 2019 with a 30 month duration. The project will support feasibility studies for renewable energy, energy efficiency audits and R&D projects.

Summing up the situation of energy efficiency in SEE states, it is evident that there is an ongoing plethora of national efforts and programmes in support of the EU long-term target to become the first "climate-neutral" continent, by 2050. However, as Eurostat[19] announced in early 2020, the EU energy consumption is rising despite the efforts to reduce it across Europe. The EU-27 gross domestic product grew rapidly, between 2014 to 2017, from €11,782billion to €13,964billion, indicating that economic activity has not yet decoupled from energy consumption.

The COVID-19 pandemic, which severely hit the European Union in 2020, is likely to result in a decrease in energy consumption in 2020, as a result of the wide spread lockdowns and slowdown of the national activities.However, it is expected that economic recovery will lead to a rebound in energy consumption, or at least bring it up to its previous levels.

Accordingly, the proposed NECPs by all EU M-S in the region and the ones to be submitted shortly from the other states, are of great importance and they must be applied with reverence and great attention to detail, in order to achieve all of the proposed targets.

17 https://www.tureeff.org/
18 https://yevdes.org/home/
19 https://ec.europa.eu/eurostat/statistics-explained/index.php/National_accounts_and_GDP#Developments_for_GDP_in_the_EU-7:_growth_since_2014

12.2 The status of Cogeneration of Heat and Power, CHP, in SE Europe

Cogeneration of Heat and Power (CHP), in 2020, delivers 11.2% of the power and 16.5% of the heat in the EU-28, saving up to 47 Mtoe or 13% of the 2020 Energy Efficiency target and up to 250 Mt of CO_2 emissions or 20% of EU's 2020 GHG target, according to COGEN EUROPE[20], the European Association for the Promotion of CHP.

The status of CHP is varying in the SE Europe states, since there are countries without any or with limited, installed CHP capacity, especially for residential and industrial purposes. According to Eurostat[21], the EU-27 and the SEE EU M-S the specific CHP data, for both cogeneration of electricity and heat, are given in Table 12.3.

Table 12.3 **CHP data for EU-27 and SEE EU M-S in 2018**

M-S	CHP electricity generation, TWh	Share of CHP in total gross electricity generation	total CHP electrical capacity, GW	of which from units with PES ≥ 10%	total CHP Heat capacity, GW	of which from units with PES ≥ 10%	Primary energy savings (PJ)
EU- 27	344.55	11.7%	133.60	112.78	280.48	222,74	1,2644.56
Bulgaria	3.64	7.8%	1.14	1.04	4.33	3.98	13.59
Croatia	1.99	14.6%	0.86	0.68	2.16	1.43	6.37
Cyprus	0.06	1.1%	0.02	0.01	0.03	0.02	0.04
Greece	2.37	4.5%	0.43	0.35	0.93	0.55	5.13
Hungary	4.29	13.4%	1.49	1.26	2.99	2.18	11.62
Romania	5.39	8.3%	1.62	0.97	4.93	2.02	11.59
Slovenia	1.30	8.0%	0.39	0.26	0.88	0.51	4.60
Total SEE M-S	**19.04**	**8.2%**	**5.95**	**4.56**	**16.23**	**10.69**	**52.94**

12.2.1 Legislation on CHP in SE European states

Until 2012, the European Directive in force for the promotion of CHP in the EU was 2004/8/EC[22]. This Directive is no longer in force, and along with the Directive 2006/32/EC, on energy end-use and energy services, have been repealed by the Energy Efficiency Directive -EED (2012/27/EU)[23] and its amendment[24].

The major issues for CHP that the EED brings are defined as:

1. The promotion of high-efficiency CHP by actions taken by the M-S.
2. Introduction to the energy system of each M-S of district heating and cooling systems.

As the countries in SE Europe are either EU M-S (Bulgaria, Croatia, Cyprus, Hungary, Greece, Romania, Slovenia) or candidate countries (Albania, North Macedonia, Montenegro, Serbia and Turkey) or potential candidate countries (Bosnia and Herzegovina, and Kosovo), they all have to transpose into national law the relevant European Directives, like EED and its amendment .
The status of the regulatory framework for CHP for all SE Europe countries is summarized in Table 12.4.

[20] https://cogeneurope.eu/knowledge-centre/cogeneration-in-2050
[21] https://ec.europa.eu/eurostat/documents/38154/4956229/CHPdata2005-2017.xlsx/871cc151-5733-423f-ae38-de9b733aa81e
[22] http://data.europa.eu/eli/dir/2004/8/oj
[23] http://data.europa.eu/eli/dir/2012/27/oj
[24] http://data.europa.eu/eli/dir/2018/2002/oj

Table 12.4 **Regulatory framework for CHP in SE Europe**

Country	Framework for CHP	Comments
Albania	No regulatory framework yet	
Bosnia and Herzegovina	Law on the use of RES & Efficient Cogeneration (Federation of Bosnia and Herzegovina-FBiH entity); Law on the use of RES & Efficient Cogeneration (Republic of Srpska-RS entity)	
Bulgaria, Croatia Hungary, Greece Montenegro, Romania	2012/27/EU & 2018/2002/EU transposed into national laws	National Laws referring to High-efficiency CHP
Cyprus	2012/27/EU & 2018/2002/EU transposed into national law: N.174(I)/2006; N.54(I)/2012; N.150(I)/2015	CHP capacity of each unit < 5 MWe and max total capacity for all units up to 20 MWe
Israel	Electricity Market Law, 1996	The Law allows competition in the electricity market, including all CHP technologies
Kosovo	Electricity Law (Law No 05/L-085) Energy Law (Law No 05/L-081)	Partially referring to CHP
Montenegro	By-laws in Energy law to meet obligations from Art. 14 of EED, Energy Development Strategy 2016–20, Energy Law (Art 20)	Promotion of District Heating Systems (DHS) and High Efficiency CHP (HECHP), Development of DHS
North Macedonia	Energy Law (2014) & new Energy Law	Expected by mid-2020
Serbia	- The Law on Energy (OG 145/14) - The Law on Efficient Energy Use Other Legal Documents: - Energy Sector Development Strategy of the Republic of Serbia for the period by 2025 with projections by 2030. OG RS 101/15 - Energy Strategy Implementation Program for 2017-30 - Regulation stipulating the requirements & procedure for acquiring the status of a privileged power producer - Regulation stipulating incentives for the production of electricity from RES and HECHP	- Articles 2,3,16,20,21, 30, 57,70,74,80,85,345,380,386 - Articles 5, 45,46 OG 25/13 - Articles 1, 2, 4, 7 (OG 56/16)
Slovenia	Energy Law, 2019 (Art. 322)	CHP w/ RES and waste heat only for DHS. Based on provisions of Energy Act 2019, a new decree in Slovenia has regulated the category of small green power facilities and devices, which produce electricity from RES and in HECHP. Advanced CHP units with the capacity of 50 kW at most, do not require a building permit to be installed.
Turkey	Law 3094/1984 & Regulation 9799/1985 Electricity Market Law 6446/2013	Promotes autoproducers. Abolish autoproducers rights Now, up to 5 MWe CHP facilities are operating at a "non-licensed" status.

12.2.2 Installed CHP Capacity in SE Europe

The installed capacity of the CHP units, in MWe/MWth, and its usage per country is given in Table 12.5, based on the most recent available data, (2020).

Table 12.5 **Installed capacity & Usage of CHP units in SE Europe**[25]

Country	Installed capacity, MWe/MWth	Usage	Comments
Albania	N/A	- biomass, in coming years	Potential for 1-1.5 MWth with
Bosnia and Herzegovina	14.45/112.5	District Heating	2021 commissioning
Bulgaria	1,141/4,331	District Heating	Eurostat Data for 2018
Croatia	860/2,155	DHS, Industry	Eurostat Data for 2018
Cyprus	16/30	Agriculture	Eurostat Data for 2018
Hungary	1494/2986	DHS, power production, industry	Eurostat Data for 2018
Greece	425/926	Agriculture, DHS, industry	Eurostat Data for 2018
Israel	761/- 218/- 3-16/-		6 units connected to Grid 3 units in commissioning Promotion of small-scale CHP
Kosovo	137.4/-	District Heating	Production: 235,080 MWhth in 2018-19
Montenegro	N/A		
North Macedonia	282/-	Power production	
Romania	1617/4926	DHS, power production, industry	Eurostat Data 2018
Serbia	596/642 (2020) 9.6/- 5/- 140/-	DHS Small-scale CHP Fuelled by RES DH in Pancevo	2019 Data:2913GWhe /2895.2 GWhth Industry: 543 GWhe / 3,070.32 GWhth 11 CHP in commissioning The fuel is biogas
Slovenia	394/879 66%combined cycle	Type of technology: heat in DH systems 29% ICE 3% Gas turbine 2% Steam turbine	Mandatory, by law, CHP and waste
Turkey	2016:6,170/- 2017:5,830/- 2018:5,100/- 2019:4,500/-	Mainly in industry; 1005 MWe in chemical 740 MWe in textile 630 MWe in petro- chemical 434 MWe in food	In 2019: 38 CHP units of 117.9 MWe installed. As of DHS, one at the Sabancı University at Istanbul with a 2.4 MWe CHP plant and 100 kW PV, supplying with yearly 16.5 GWh electricity and 10.4 GWh heat, 85% of the demand of the campus.

[25] https://ec.europa.eu/eurostat/documents/38154/4956229/CHPdata2005-2017.xlsx/871cc151-5733-423f-ae38-de9b733aa81e
[26] https://www.energy-sea.gov.il/English-Site/Pages/About-Us.aspx Israeli Ministry of Energy

12.2.3. Incentives for the promotion of CHP in SE Europe

The incentives for the promotion of cogenerated electricity in all SE Europe countries are summarized in Table 12.6. The support schemes include Feed-in-Tariffs (F-i-T) or Feed-in-Premium (F-i-P).

Table 12.6 **Supporting Scheme for CHP in SE Europe**

Country	Support Scheme	Comments
Albania	N/A	
Bosnia and Herzegovina	N/A	
Bulgaria	Priority of CHP connection to Grid, Obligatory purchase of cogenerated electricity at F-i-T, until 12/2018, Certificates of Origin, by 1/2019 and F-i-T replaced by F-i-P	From 1/2019 cogenerators have to sell to the Electricity Xchange at F-i-P
Croatia	CHP allocation: There is no regulated or required method of CHP cost allocation in Croatia. In practice, CHPs allocate operating expenses directly to electricity and heat where possible; expenses that cannot be directly allocated to either product are allocated according to the share of direct expenses of each product. So, if 60 % of directly allocated operating expenses were allocated to electricity, 60 % of the operating expenses that could not be directly allocated to either heat or electricity would be allocated to electricity. Obligation to buy excess cogenerated electricity by the Transmission System Operator at certain proportion determined by Government's Ordinance issued every 31st October Regulation of the status of eligible electricity produced to eliminate inconsistencies Guarantee of origin for cogenerated electricity	Government provides State Aid programs for HECHP according to applicable rules on state aid in Croatia
Cyprus	Net-billing	
Hungary	From 2011, energy policy shift as F-i-T scheme abolished for cogenerated electricity. Some units closed/paused activities, but, some other cogenerators formed regulatory centres, offering their flexibility to the Transmission System Operator, as virtual power plants.	Heat has a regulated price, set each year before the heating season. Decrease of cogenerated electricity by 26%, between 2010 to 2018.

Table 12.6 **Supporting Scheme for CHP in SE Europe**

Country	Support Scheme	Comments
Greece	The supporting scheme is prescribed by Law, to the "main activity CHP producers - independent producers", through guaranteed F-i-T, only for the High Efficiency cogenerated electricity fed into the System or Grid, including the Grid of the Non-Interconnected Islands, on the basis of a defined price, expressed in €/MWh of electricity of a definite time period.	L.4414/2016, Art.4, defined the F-i-Ts for cogenerated electricity fed to the Network or the Grid at a constant value, depending on the used technology, in €/MWh plus a natural gas correction coefficient (NG CC). This correction is introduced to adjust the price of cogenerated electricity from HECHP plants, based on the standard plant efficiency and the market gas price.
Israel	Fully liberated energy market: Cogen electricity is sold to any power consumer through the national power grid. Cogen Heat is either for self-use or for sale to end-consumers at a price that is negotiated between the partners.	At periods with surplus electricity: compensation with tariff, predetermined by project basis, up to 2018. Ever since, there is no bilateral sale of cogenerated electricity for new CHP units. In 2019, incentives were announced for energy production with cogeneration, for a total of 300 MW. The provision is aimed at all industries and "kibbutzim" in Israel that intend to self-produce electric and thermal energy, relying on CHP installations with a maximum power of 16 MWe. The installations will be able to sell energy to the grid and be entitled to a premium for energy production using CHP plants. The only concern relates to poorly developed gas infrastructures in these areas.
Kosovo	N/A	

Table 12.6 **Supporting Scheme for CHP in SE Europe**

Country	**Support Scheme**	**Comments**
Montenegro	There is a supporting scheme for high-efficient CHP in the form of F-i-T	The tariffs are set based on the installed capacity: - < 1 MWe, the F-i-T is 100 €/MWh. - 1 to 5 MWe, the F-i-T is calculated by the formula [100-5 x (Pinst-1)], in €/MWh, where Pinst is the installed electric capacity. - 5 to 10 MWe, F-i-T is 80 €/MWh
North Macedonia	N/A	
Romania	CHP allocation: Romania has a diverged energy market where the electricity generation and gas markets have been liberalized while the price of heat delivered to DH systems remains regulated by ANRE. The regulated production price for heat from a CHP plant is set by calculating a reference price for an equivalent HOB that uses the same type of fuel as the CHP. CHP allocation: Romania has a diverged energy market where the electricity generation and gas markets have been liberalized while the price of heat delivered to DH systems remains regulated by ANRE. The regulated production price for heat from a CHP plant is set by calculating a reference price for an equivalent HOB that uses the same type of fuel as the CHP. Since 2011, for cogenerated electricity, with natural gas and coal, have introduced the bonus-type support, notified to the EC in accordance with European regulations on state aid. The government decision allows CHP plants to benefit from operating aid that covers the difference between production costs and market prices. The Romanian authorities have calculated a "bonus", which is a sum per MWh of electricity produced, calculated as the difference between the market price for electricity expected over the period of application of the scheme and the total production costs of a typical CHP plant. The amount of aid granted to each CHP plant benefiting from the scheme will be the applicable bonus multiplied by the electricity produced by the plant and sold on the market. The Decision accounts for the differences between the costs of different types of fuels and different conditions of fuel supply. The bonus is calculated for three types of CHP: solid fuel-based, gas-fired that is directly supplied from the transmission network, and gas-fired supplied through a distribution network.	For each of the three types of fuels, the bonus (€/MWh) is calculated according to the following formula: $BONUS=\frac{(T\_Costs-R\_Elec-R\_Heat)}{Electricity}$ where: TCosts = variable costs + fixed costs + return on capital (€) RElec = income from the sale of the electricity delivered by the CHP plant at electricity market price (€) RHeat = income from the sale of the heat produced in the typical CHP plant at the price for heat (€) Electricity = the amount of electricity delivered annually by the CHP plant (MWh) Variable costs mainly include fuel costs, whereas fixed costs refer to operating and maintenance costs (including personnel expenses) and depreciation costs. The evaluation of the productions costs also takes into account a (maximum) 9% return on capital.

Country	Support Scheme	Comments
Serbia	CHP allocation: There is no formally adopted CHP cost-allocation formula in Serbia. CHP do allocate costs to electricity and heat products in practice. For example, the DH company in Novi Sad, the second largest city in Serbia, allocates operating and maintenance costs equally to power and heat in its two gas-fueled 10 MW CHPs, but does not specifically allocate capital costs. The electricity product of the CHP benefits from sales to the national grid, as electricity generation in CHPs is more efficient than alternative electricity generation. The heat product of the CHP does not benefit from this allocation, however, because the heat production efficiencies of the CHP plant and a gas-fueled HOB are nearly equivalent. Industrial companies that integrate natural gas-fuelled high-efficiency CHP plants up to 10 MW are entitled to acquire a privileged power producer status and receive an incentivised purchase price for the amount of delivered electricity.	
Slovenia	Support up to 20 MWe CHP units, for a maximum period of 10 years	
Turkey	Various incentives to promote CHP including the most important ones like: 1. "unlicensed generation" for CHP up to 500 kWe, including micro-CHP (<50 kWe) 2. Cogeneration facilities are deemed eligible and have the right to select their suppliers.	

Summing up, the total installed CHP capacity in SEE EU M-S corresponds to 5.2% of the total installed capacity in EU-27. However, the share of CHP in gross electricity generation ranges from 8.2% to 11.2% in each country, which is lagging behind the average EU-27 share (26.8%). In addition, almost all SEE countries, with the exception of Albania, have integrated CHP units in their energy systems, mainly for providing heat to local district heating systems, for industrial applications or for agricultural purposes.The various countries apply different type of incentives for promoting Cogeneration. The most schemes are the "feed-in-tariffs" or "feed-in-premium".

The Cogeneration of Heat and Power (CHP) is characterized by the EU and its various European directives, as an energy efficient technology. However, considering that the share of cogenerated electricity in gross electricity consumption is very low in all EU M-S, there is a need to place more emphasis on the further promotion of HECHP.

In this direction, concerted actions should be taken, especially through the implementation of the NECPs, in order to increase the share of HECHP by 2030.

13

Energy Technology Perspectives in SE Europe

The Electricity Sector

13.1 The Role of Technologies in SE Europe's Energy Transition

Energy technology is an engineering science whose main purpose is the efficient, safe, environmentally friendly and economically viable extraction, conversion, transportation, storage and use of energy, preventing at the same time side effects on humans, nature and the environment. After the Second World War, huge progress has been achieved in developing a variety of energy technologies used globally, while continuous technological progress has resulted in numerous improvements and higher efficiencies as well as the introduction of new low-carbon technologies.

The technologies used across the energy sector have a catalytic effect on how efficient and environmentally responsible one can utilize the various energy sources available. Thanks to efforts undertaken over the last few years, especially after the first oil crisis of 1973, by several research organizations, by academia and industry worldwide, we have today several technologies available which we can use to transform both conventional and alternative energy sources into useful work. In developing new types of energy technologies over recent years, a lot of emphasis has been placed on advanced systems, techniques and materials which can tap Renewable Energy Sources (RES), such as wind, solar, geothermal, hydro, biomass, ocean and wave energy. RES technologies and energy efficient systems have come to be known as «Appropriate Technologies» in the sense that they help minimize environmental impact (and hence lower emissions) and help towards greater use of renewable energy.

But there is a host of other technologies, which equally contribute towards achieving lower emissions. These are to be found in power generation from natural gas (which emits 50%+ lower GHGE's compared to coal), hydrogen (which in the case of blue hydrogen derives from gas), Carbon Capture Utilization and Storage (CCUS), which help contain emissions from coal and lignite burning, and of course nuclear power which is an almost zero emitter. These technologies are of equal importance to the RES ones since they are related to conventional energy sources such as oil, gas and coal – which currently form the main stay of energy used in buildings, for transportation and for power generation, and are likely to remain relevant over the next 20-30 years, which is broadly known as the transition period.

As "energy transition" takes hold and SE Europe embraces decarbonization and energy efficiency, the role of technologies to be applied by the various countries and for the different energy resource base to be found across the region acquires special significance. In many cases the choice of the right technology could prove key in efforts to lower emissions and achieve energy sustainability.

Hence, the main purpose of this section of the "Outlook" study is to identify, describe and assess the technologies involved which are sustainable, tested and can be applied immediately or in the near future in the SEE region on a competitive economic basis. A review of such technologies is undertaken in section 13.3, while section 13.2 discusses the main issues involved with clean energy innovation, which by many is regarded as key in our effort to attain a net-zero emission environment over the coming years. In view of the current situation in SEE, where solid fuels still play leading role for power generation, setting net-zero goals may appear utopian. Abandoning coal for power generation and industrial use is no doubt a hard choice to make by most countries in the SEE region as they appear to be a safe, reliable and abundant indigenous source, which guarantees energy security. However, switching to clean energy fuels is the prevailing trend in energy policy, already supported by a panoply of UN decisions, EU Directives and banking regulations (e.g. EIB, EBRD), and adaption and implementation, sooner or later, at regional level appears inevitable. Fulfilling such ambitious targets can only be achieved by use of the right technologies.

One final point to make in discussing the switch to clean energy fuels in the SEE region is directly linked to technology adaptation and the profound changes that this will have on societal and employment patterns. The re-tooling, even gradual, of the entire technological base on a clean energy and low carbon model, will affect the way in which we live and work while it will drastically impact the production and industrial base of society. Hence, the passover to clean technologies for entire economies is not just a matter of clever gadgets and technology gimmicks but implies a far deeper and more fundamental change. It will often lead to a change of lifestyle patterns, revised societal organization, new professions and employment trends, a fully digitalized environment and novel approaches to education. More than a technology change adopting clean energy technologies on a massive scale, throughout the product value chain, will result in a completely different approach to several other areas of human activity including on how we see, understand, appreciate and react to our environment. The effective protection of our environment from careless and ill-conceived human interference and from extreme weather phenomena will be enhanced by the new clean fuel culture which will result from our drive to work with nature (rather than against it) and our will to protect the biosphere.

13.2 Clean Energy Technologies

As we move further into energy transition, the role of clean energy technologies is becoming even more relevant. Given that many countries, and the EU in particular, are adopting net-zero emission policies for 2050, achieving such ambitious targets "requires a radical transformation in the way we supply, transform and use energy", notes the IEA in its Energy Technology Perspectives 2020 report[1]. The rapid growth of wind, solar and electric cars has shown the potential of new clean energy technologies to bring down emissions. Net-zero emissions will require these technologies to be deployed on a far greater scale, in tandem with the development and massive rollout of many other clean energy solutions that are currently at an earlier stage of development, such as numerous applications of hydrogen and carbon capture. The IEA's Sustainable Development Scenario[2]– a roadmap for meeting international climate and energy goals – brings the global energy system to net-zero emissions by 2070, incorporating aspects of behavioral change alongside a profound transformation in energy system technology and infrastructure.

According to the IEA, today we have 800 technology options that we can choose from to drive emissions to net zero by 2050. In SEE, we obviously need to narrow down our search for available and realistic technology options and settle down to the ones, which are commercially available and cost effective. These options are presented in section 13.3 further on. In selecting the appropriate technologies, one should bear in mind that apart from power generation, where a lot of attention is now focused as the switch away from coal is taking precedence, a lot more attention will need to be given to the transport, industry and buildings sectors, which today account for more than 55% of CO_2 emissions from the energy system.

As the IEA notes, spreading the use of electricity into more parts of the economy is the single largest contributor to reaching net-zero emissions. In IEA's Sustainable Development Scenario, final electricity demand more than doubles. This growth is driven by using electricity to power cars, buses and trucks; to produce recycled metals and provide heat for industry; and to supply the energy needed for heating, cooking and other appliances in buildings.

Reaching net-zero emissions in 2050 would require a much more rapid deployment of low-carbon power generation. In IEA's Faster Innovation Case, electricity generation would

1 IEA (2020), "Energy Technology Perspectives 2020", https://iea.blob.core.windows.net/assets/7f8aed40-89af-4348-be19-c8a67df0b9ea/Energy_Technology_Perspectives_2020_PDF.pdf
2 IEA (2021), "Net Zero by 2050 - A Roadmap for the Global Energy Sector", https://iea.blob.core.windows.net/assets/4719e321-6d3d-41a2-bd6b-461ad2f850a8/NetZeroby2050-ARoadmapfortheGlobalEnergySector.pdf

be about 2.5 times higher in 2050 than it is today, requiring a rate of growth equivalent to adding the entire US power sector every three years. Annual additions of renewable electricity capacity, meanwhile, would need to average around four times the current record, which was reached in 2019.

Although much greater electrification appears to be one of the main pillars driving energy transition, it is generally agreed that electricity alone cannot decarbonize entire economies. In the case of SEE, apart from the further penetration and large scale use of renewables in the electricity mix in the different countries of the region, we also need to examine in depth, as a matter of priority, a number of other more "novel" approaches, including hydrogen, CCUS and synthetic fuels.

As we shall see later in this Chapter, the use of low-carbon hydrogen is part of SEE's energy transition agenda and hence a large amount of electricity will be required for its generation. This will entail the building up of serious electrolyser capacity - with electrolysers producing hydrogen from electricity - in different countries. With electrolyser consuming huge amounts of electricity, this proves a formidable barrier. However, this hydrogen forms a bridge between the power sector and industries where the direct use of electricity would be challenging, such as in the production of steel from iron ore or fuelling large ships.

Carbon capture and bioenergy have a definite role to play in several SEE countries which largely depend on coal and lignite for power generation. Capturing CO_2 emissions in order to use them sustainably or store them (known as CCUS) is a technology crucial for reaching net-zero emissions. In IEA's Sustainable Development Scenario, CCUS is employed in the production of synthetic low-carbon fuels to remove CO_2 from the atmosphere. It is also vital for producing some of the low-carbon hydrogen that is needed to reach net-zero emissions, mostly in regions with abundant and low-cost natural gas resources and available CO_2 storage. At the same time, the use of modern bioenergy triples from today's levels. It is used to directly replace fossil fuels (e.g. biofuels for transport) or to offset emissions indirectly through its combined use with CCUS[3].

As the IEA rightly points out, a secure and sustainable energy system with net-zero emissions results in a new generation of major fuels. The security of today's global energy system is underpinned in large part by mature global markets in three key fuels – coal, oil and natural gas – which together account for about 70% of global final energy demand. It is forecasted that electricity, hydrogen, synthetic fuels and bioenergy will end up accounting for a similar share of demand in the Sustainable Development Scenario as fossil fuels do today.

13.3 Review of Clean Energy Technologies in SE Europe

3.1 Renewable Energy Technologies

Renewables can be used for a wide variety of applications ranging from power generation to heat generation and transportation. Most of Renewable Energy Sources (RES) technologies are suitable for use in SE Europe. Table 13.1 summarizes the different applications. Already, a wide variety of RES technologies are used by most countries in the region. But there is huge potential for further use by both existing applications, such as solar thermal and solar PV, wind, hydro and biomass but also from other, such as geothermal, biofuels, biomethane, offshore wind and ocean energy.

Renewable energy can contribute to grid-connected electricity generation but has also a large scope for off-grid applications and can be most suitable for remote and rural applications. A brief description of selected renewable energy technologies of current and potential use in the SEE region follows.

[3] IEA (2020), "Energy Technology Perspectives 2020 – Special Report on Carbon Capture Utilisation and Storage", https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf

Table 13.1 **Comparative Table of RES Technologies and Applications**

Renewable energy technology	Energy service/application	Area of application
Wind turbines – grid-connected	Residential and industrial electricity, supplementing mains supply	Mostly urban
Wind turbines – stand-alone	Power for lighting and other low-to medium electric power needs	Urban and rural
Wind pumps	Pumping water (for agriculture and drinking)	Mostly rural
Solar PV – grid-connected	Residential and industrial electricity, supplementing mains supply	Mostly rural
Solar PV – stand-alone	Power for lighting and other low-to medium-voltage electric needs	Urban and rural
Solar PV pumps	Pumping water (for agriculture and drinking)	Mostly rural
Solar thermal power plant – grid-connected	Residential and industrial electricity, supplementing mains supply	Mostly rural
Solar thermal – water heaters	Heating water	Urban and rural
Solar thermal – dryers	Drying crops	Mostly rural
Solar thermal – heating **Solar thermal – cooling**	Air-conditioning (centralized system for buildings, etc.), cooling for industrial processes	Mostly rural
Solid biomass	Cooking and lighting (direct combustion), motive power for small industry and electric needs (with electric motor)	Mostly rural
Liquid biofuels	Transport fuel and mechanical power, particularly for agriculture, heating and electricity generation, some rural cooking fuel	Urban and rural
Large hydro – grid connected	Residential and industrial electricity, supplementing mains supply	Urban and rural
Small hydro	Lighting and other low-to-medium voltage electric needs, process motive power for small industry (with electric motor)	Mostly rural
Geothermal	Grid electricity and large-scale heating	Urban and rural
Village-scale	Mini-grids usually hybrid systems, solar, and/or wind energy with diesel engines. Small-scale residential and commercial.	Mostly rural, some peri-urban

Source: UNIDO (2009) [4]

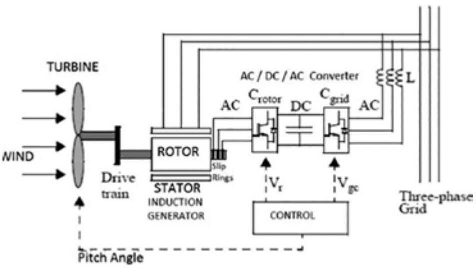
[4] UNIDO (2009), "Sustainable Energy Regulation and Policymaking Training Manual", https://www.unido.org/fileadmin/media/documents/pdf/training_manual_on_sustainable_energy_regulation_and_policymaking_for_Africa.pdf

A. Wind energy

The utilization of wind energy, mostly in the form of onshore or offshore wind farms, has a wide range of applications in all countries in SE Europe. As explained in Chapter 11, significant advance have been made over the last five to ten years, resulting in hundreds of wind farm installations in all 15 countries in SEE, being reviewed in this Study. All these wind farms are onshore while interest is growing fast for offshore installations.

Latest information suggest that Greece and Romania will be the first countries in the region to harvest offshore wind energy. A wind turbine generates power by converting the force of the wind acting on the rotor blades into torque. Figure 13.1 depicts the components of a wind energy system and Table 13.2 presents its advantages and disadvantages.

Figure 13.1 **Wind Energy Conversion System with Three Types of Components**



Source: Abdulhakeem, E. (2020) [5]

Table 13.2 **Strengths and Weaknesses of Wind Energy Systems**

Strengths	**Weaknesses**
Technology is relatively simple and robust with lifetimes of over 15 years without major new investment	Site-specific technology (requires a suitable site)
Automatic operation with low maintenance requirements	Variable power produced therefore storage/back-up required
No fuel required (no additional costs for fuel nor delivery logistics)	High capital/initial investment costs can impede development (especially in developing countries)
Environmental impact low compared with conventional energy sources	Potential market needs to be large enough to support expertise/ equipment required for implementation
Mature, well developed, technology in developed countries	Cranage and transport access problems for installation of larger systems in remote areas
The technology can be adapted for complete or part manufacture (e.g. the tower) in developing countries	

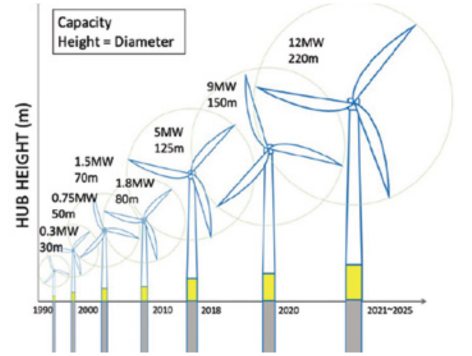
Source: UNIDO (2009)

In most cases, wind energy systems are classified in three categories: (a) grid-connected electricity generating, (b) stand-alone electricity generating and (c) mechanical systems.

Several turbine types exist, but the most common configuration not only in SE Europe but also at a global level has become the horizontal axis three bladed turbine. Modern wind turbines vary in size with two market ranges: small units rated at up to 50-80 kW in capacity, used mainly for rural and stand-alone power systems; and large units, from 150 kW up to 5 MW in capacity, used for large-scale, grid-connected systems. Lately, wind turbine models in the range of 3.0-3.5 MW have become the mainstay in wind farm applications, while the next range in terms of scale aim for until of 5-8 MW for onshore applications and above 10 MW for offshore installations.

[5] Abdulhakeem, E. (2020), "Modelling & Simulation of a Wind Turbine with Doubly-Fed Induction Generator (DFIG)", https://www.researchgate.net/publication/345596647_Modelling_Simulation_of_a_Wind_Turbine_with_Doubly-Fed_Induction_Generator_DFIG

Figure 13.2 **Growth in Size of Commercial Wind Turbines**



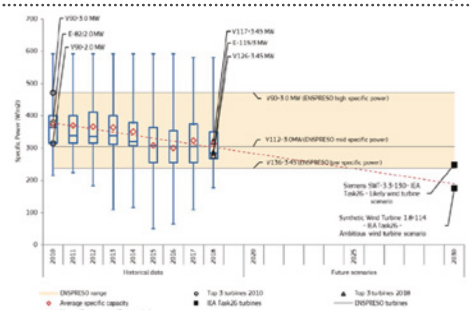
Source: Wind Europe and IRENA

Onshore wind

As reported by JRC[6], since 2010 a clear downward trend can be witnessed in the specific power of onshore wind turbines deployed in the EU (see boxplots of historical data in Figure 13.3). The specific power of a wind turbine is defined through the ratio of the rated capacity of the turbine to the swept area of its rotor. Hence, this trend also meant a change in the turbine models deployed. In 2010, predominantly wind turbines with a rated capacity between 2 MW and 3 MW and blade lengths below 90m were among the top turbines deployed such as models from Vestas (V90-3.0MW and V90-2.0MW) and Enercon (E-82/2.0MW), resulting in an average specific power of about 370 W/m2. Although there was an increase of rated capacity until 2018 the relatively stronger increase in blade length resulted in a decline of the average specific power to about 310 W/m2, which translates into a decrease by 16% as compared to 2010-values. In 2018 the top 3 turbines deployed in the EU were the Vestas V126-3.45MW followed by Enercon's E-115/3MW and the Vestas V117-3.45MW.

Assuming the continuation of this trend would result in an average specific power of about 180 W/m2 by 2030. Figure 13.3 shows the current and/or future assumptions on the specific power from studies analysing the impact of different land-based wind turbine designs on grid integration (IEATask26 group) or from the JRC-ENSPRESO (ENergy Systems Potential Renewable Energy Sources) database providing technical potentials for wind energy. The JRC-ENSPRESO dataset defines three characteristic wind turbines spanning from a turbine model (Vestas V90-3MW) with high specific power (472 W/m2) followed by a mid-specific power Vestas V112-3MW turbine (305 W/m2) to a V136-3.45MW turbine with a relatively low specific power (238 W/m2). The study performed by IEA Task26 group uses as a reference turbine a GE 2.75-103 (330 W/m2) within its 'Business as Usual' scenario. Apart from that, two future scenarios are defined: the 'Likely' wind turbine scenario considering a turbine technology (Siemens SWT 3.3-130) which will most likely characterise the European situation in 2030 with a specific power of 250 W/m2 at a hub height of 125m, and an 'Ambitious' wind turbine scenario assuming a synthetic turbine based on the Gamesa G114-1.8MW with a specific power of 175 W/m2 at a hub height of 150m.

Figure 13.3 **Evolution of Specific Power of Onshore Wind Farms in the EU and Scenario Assumptions of the ENSPRESO Dataset and the IEATask26 Group**



Source: JRC

In order to understand the effect of deploying wind turbines with different specific power, the capacity factor (CF) of three representative turbines has been calculated by JRC.

The following assumptions are made on turbine technology, turbine location and wind resource:

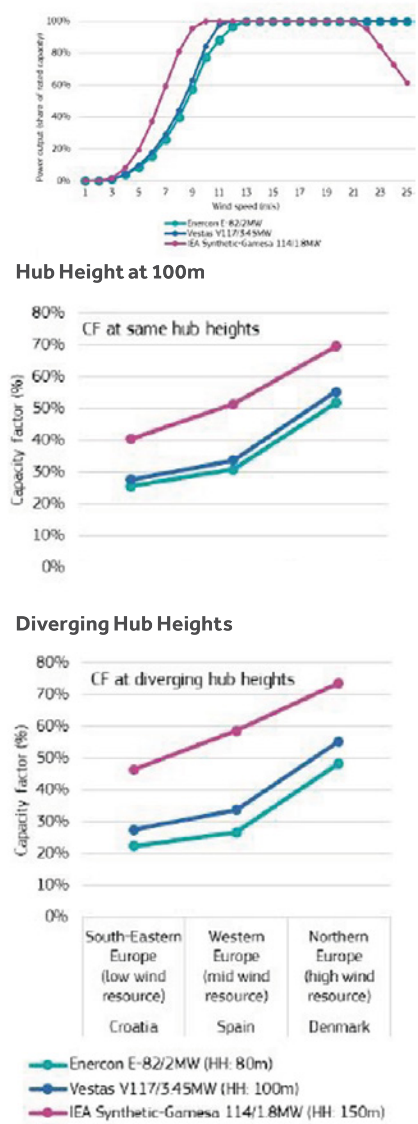
[6] JRC (2020), "Wind Energy - Technology Development Report 2020", https://publications.jrc.ec.europa.eu/repository/handle/JRC123138

- **High specific power turbine:** Enercon E-82/2.0MW with a specific power of 379 W/m2 deployed at a hub height of 80m (turbine model is both among the top3 deployed turbines and converging with the average specific power in 2010)
- **Mid specific power turbine:** Vestas V117-3.45MW with a specific power of 321 W/m2 deployed at a hub height of 100m (turbine model is both among the top3 deployed turbines and converging with the average specific power in 2018)
- **Low specific power turbine:** IEA Synthetic-Gamesa 114/1.8MW with a specific power of 176 W/m2 deployed at a hub height of 150m (representing an ambitious turbine model in terms of average specific power in 2030)
- **Turbine location:** Three different EU countries are selected as case studies in order to represent diverging wind resources across Europe: Croatia (South Eastern Europe – low wind resource), Spain (Western Europe – mid wind resource), Denmark (Northern Europe – high wind resource)
- **Wind resource:** For each country the hourly wind resource was derived for one specific site from the EMHIRES database for the year 2016 [Gonzalez Aparicio et al. 2016, Gonzalez Aparicio et al. 2017]. The site chosen represents the respective country's median wind farm location based on its wind resource. Wind speeds at 50m from the EMHIRES database were extrapolated to the respective hub height by using the wind profile power law3.
- **Other:** The calculation is performed in hourly time-steps for the single wind turbine. Thus, additional losses, which appear in a multi-turbine wind park and decrease the CF of an entire wind farm, are not considered (e.g. wake effects, transmission losses, turbine availability, etc.)

A decrease in specific power allows to harvest the wind resource more efficiently in the lower wind speed range before reaching the rated capacity of the turbine. JRC case studies show that the wind turbines operate below rated capacity most of the time during the year.

Notably, the low and mid resource case studies benefit more in terms of capacity factor increase from applying a low specific power turbine which is the case for most countries in SE Europe than in a high wind resource country such as Denmark because of the higher gains in the lower wind speed range.

Figure 13.4 **Selected Power Curves (High to Low Specific Power) and Resulting Capacity Factors in Three EU Countries With Diverging Wind Resources and Hub Heights**



Source: JRC

Within this context, the trend to longer blades in Europe continues, with about 76% of the installed capacity in 2018, deploying wind turbines with rotors diameters of more than 100m (as compared to only about 2% in 2010). Therefore, the average rotor diameter within Europe increased by 31% since 2010 to about 108m. In the period 2010-2018, the average rotor diameter is found to be largest in Finland (121m) followed by Denmark (109m), Sweden and Germany (both 106m). In 2019, several Original Equipment Manufacturers (OEMs) announced or installed prototypes of their new onshore wind platforms targeting the 5 MW+ segment with increased rotor sizes (see Table 13.3).

Table 13.3 **Onshore Wind Platforms in the 5 MW Segment and their Respective Rotor Size**

OEM	Platform	Rated capacity	Rotor diameters	Status
Vestas (DK)	EnVentus	5.6 MW	150m, 162m	Prototypes in 2019 and 2020
GE Renewable Energy (US)	Cypress	5.3 MW	158m (two-piece blade design)	Prototype installed end 2018
Enercon (DE)	EP5	5 MW	147m	Initial power rating of platform at 4.3MW which will be uprated to 5MW by 2020
Siemens Gamesa Renewable Energy (SGRE) (DE/ES)	5.X platform	5.8 MW 6.6 MW	155m, 170m	Prototypes in mid 2020 and Q3 2020 Installation of 6.6 MW foreseen in Q2 2021
NordexAcciona (DE)	Delta4000	5 MW	149m, 163m	Prototype in second half of 2020

Source: JRC

Offshore wind

Apart from onshore wind, offshore wind is also expected to grow rapidly. Deploying turbines in the sea takes advantage of better wind resources than at land-based sites. Therefore, new offshore turbines are able to achieve significantly more full-load hours depending on resource availability. According to the IRENA[7], the key emerging trends for offshore wind from a technological, location-specific and technological coupling perspective are as follows (also visually presented in Figure 13.5):

- Manufacturing of larger offshore wind turbines; for example, Vestas recently announced the development of a 15 MW offshore wind turbine to be installed in 2022 and to begin production in 2024.
- Floating foundations enabling installations in deeper waters and farther from shore; for example, Norway's Hywind Tampen floating offshore wind farm will be located 140 kilometres from shore in depths between 260 metres and 300 metres.
- Use of versatile foundations and structures; for example, concrete substructures.
- Creation of combined-technology power generating plants such as the Eco Wave Project; for example, offshore wind could be coupled with floating solar PV and/or ocean energy technologies.
- Creation of offshore energy hubs for renewable power production; for example, two artificial wind energy islands are being developed in Denmark (the first phase of 3 GW plans to be operational by 2033 with a total investment of €29 billion.
- Powering and decarbonising sectors of the "blue economy"1 through direct and indirect electrification; for example, the BIG HIT project in the Orkney Islands in Scotland.
- Generation of green hydrogen through coupling with different offshore renewable technologies; for example, the AquaVentus consortium in Germany, with an electrolyser capacity of 10 GW, is currently the largest planned offshore wind and green hydrogen project.
- Airborne wind energy systems, which are currently undergoing demonstration projects; for example, the Skysails Skypower100 pilot project is under way in northern Germany.

So far, almost all focus in Europe has been on offshore wind coming from the North Sea. Yet slowly, stakeholders are discovering the potential of the Baltic Sea, the SE European waters and the Black Sea. A recent World Bank analysis[8] estimated the technical offshore wind potential for Bulgaria and Romania alone to be more than 100 GW. While amounting to only a fraction of that of the North Sea, it nevertheless equals about five times Romania's installed electricity generation capacity.

[7] IRENA (2021), "Offshore Renewables – An action agenda for deployment", https://www.irena.org/publications/2021/Jul/Offshore-Renewables-An-Action-Agenda-for-Deployment

[8] World Bank (2020), "Going Global : Expanding Offshore Wind to Emerging Markets (Vol. 16) : Technical Potential for Offshore Wind in Black Sea - Map (English)", https://documents.worldbank.org/en/publication/documents-reports/documentdetail/718341586846771829/technical-potential-for-offshore-wind-in-black-sea-map

The potential for Ukraine, a member of the European Energy Community, is two and half times that of Bulgaria and Romania combined. This makes offshore wind far more important for Ukraine than its coal reserves.

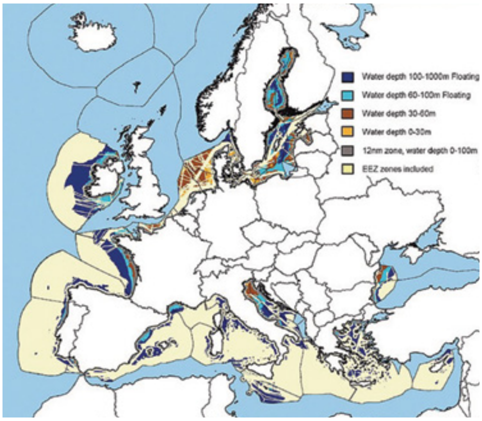
Currently, Greece has 4 GW of installed wind energy, all onshore, covering 12% of its electricity demand. Given the depth of Greek seas, the potential is highest for floating offshore wind. EDPR and Engie's Ocean Winds joint venture recently announced plans to team up with Terna Energy to co-develop 1.5 GW of floating offshore wind projects in Greek waters. The partners plan to first identify the most suitable areas and then draw up a complete project plan. Equinor, Copenhagen Offshore Partners and Principle Power are among other offshore wind players scouting out opportunities.

Admittedly, not all offshore wind investments are economical yet, given the costs, especially for floating offshore wind. At the same time, however, costs are falling rapidly and, in many cases, fixed offshore installations no longer require subsidies. Load factors of 50% or even more, i.e. the time the installation produces electricity, are an important element in this. Other renewable technologies have load factors that are about half that amount, according to an analysis provided by CEPS[9].

When looking at the EU and Energy Community members in the Black Sea, offshore wind may well be the region's best bet to meet the objectives of the Green Deal. As surprising as it may sound to some, offshore wind can also be a solution for landlocked countries such as Hungary, Serbia, Moldova and North Macedonia. A precondition would be the adequate development of the regional transmission grid.

A 2020 JRC study[10] showed that the technical potentials for offshore wind in EU-27 EEZ[11] zones are highest in the Atlantic Ocean (1,447 GW), followed by the Mediterranean Sea (1,445 GW), Baltic Sea (1,183 GW), North Sea (437 GW) and the Black Sea (160 GW) (see Map 13. 1). Areas with sea depths necessitating the deployment of floating offshore wind are vast (2,468 GW) and promising for countries with steeper coastlines (Atlantic Ocean (1,066 GW) and Mediterranean Sea (819 GW)). The floating offshore potential of the EU-27 in the North Sea is limited to 30 GW. Still the North Sea (284 GW) and the Baltic Sea (225 GW) offer most of the technical potential for projects in shallower waters (up to 60 m depth and outside the 12 nm-zone).

Map 13.1 **JRC ENSPRESO Technical Potentials for Offshore Wind in Sea Basins Accessible to EU27 Countries**



Source: JRC

As a recent study[12] by ETH Zürich and Imperial College indicates, offshore wind in southern regions will make a significant contribution to the stability and flexibility of the EU grid as a whole, due to different and in this case complementary weather patterns across the continent.

9 Kustova, I. and Egenhofer, C. (2020), "Offshore wind from the Black Sea can deliver the Green Deal for South East Europe", CEPS, https://www.ceps.eu/offshore-wind-from-the-black-sea-can-deliver-the-green-deal-for-south-east-europe/

10 Peteves, E. et al. (2020), "Striving For A Competitive EU Offshore Renewable Energy Strategy Delivering On The Green Deal", European Commission, Joint Research Centre (JRC), Petten, The Netherlands, http://www.europeanenergyinnovation.eu/Articles/Autumn-2020/Striving-for-a-competitive-EU-Offshore-Renewable-Energy-strategy-delivering-on-the-Green-Deal

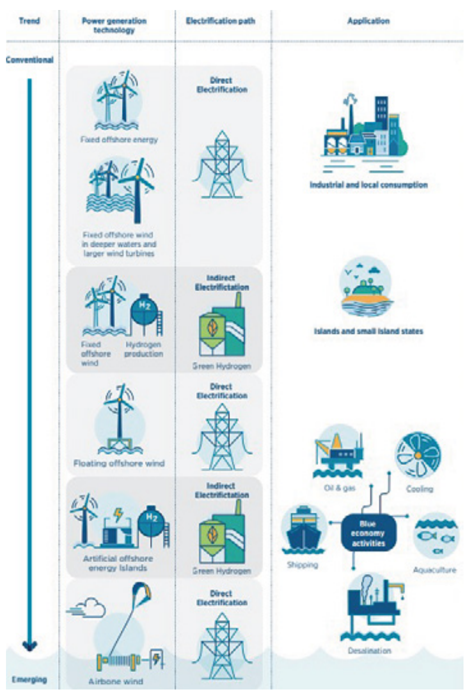
11 Exclusive Economic Zone (EEZ). Technical potentials include the territorial waters (12 nm-zone) and areas with a water depth down to 1000 m. For detailed restrictions on the technical potentials please refer to the JRC ENSPRESO dataset.

12 Grams, C. et al. (2017), "Balancing Europe's wind-power output through spatial deployment informed by weather regimes", Nature Climate Change, Volume 7, pp. 557-562, https://www.nature.com/articles/nclimate3338

Furthermore, offshore wind is suitable for the production of green hydrogen.

Wind energy in the region is not unknown. Romania currently has the largest onshore wind farm in the EU. The country's Hidroelectrica has announced a plan for a 300 MW offshore wind farm for the first time. Both Bulgaria and Romania were among the first countries to achieve the national renewable energy target.

Figure 13.5 **Key Emerging Technological Trends for Offshore Wind**



Source: IRENA

Greece is forging ahead with phasing out coal and expanding renewables. The legal framework for offshore wind farm investments has been completed (September 2021) and final decisions at the energy ministry are expected by early 2022. Competitive procedures offering offshore areas to prospective investors is the most probable approach that will be adopted for this emerging sector in Greece. Floating offshore wind parks are expected to emerge as the favored technology as a result of the great depth of Greek seas. The current proposal at the minister's office entails the staging of tenders even for preliminary research, an approach that has been adopted by other EU member states. But this could change in favor of a model preferred by market players, through which offshore concessions would be made available to investors following related applications for preliminary research such as wind velocity measurements.

Although not a single offshore wind farm operates as yet in SE Europe, interest is high and a number of applications have already been filed with regulations in Greece, Turkey, Bulgaria, Romania and Croatia. Because of strong winds, steady wind regimes and manageable sea depth, industry's interest has focused in the North Sea and the Baltic area. The lessons learned so far in terms of technologies emplaced and market operation can be most useful in promoting offshore wind in SEE. Competitive tendering procedures have led to a decline in the costs for offshore wind projects.

B. Solar energy

Solar energy technologies can be divided into two categories: (a) solar thermal systems and (b) solar photovoltaic systems.

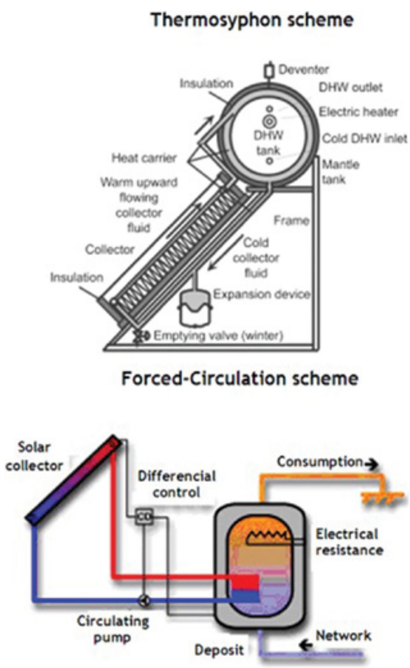
(a) Solar thermal systems

Solar thermal systems use the sun's power in terms of its thermal or heat energy for heating, drying, evaporation and cooling. Many countries in SE Europe have indigenous products such as solar water heaters, solar grain dryers, etc. These are usually local rather than international products, specific to a country or even to a region. The main solar thermal systems employed in most of SE European countries are analyzed briefly below.

Solar water heating

Solar water heating systems are mainly used in households but also in hotels, hospitals, schools as well as for light industrial needs. The principle of the system is to heat water, usually in a flat plate collector and store it in a tank until required. Collectors are designed to collect the heat in the most efficient, but cost-effective way, usually into a heat transfer fluid, which then transfers its heat to the water in the storage tank. The two main types of collector are flat plate and vacuum tube. There are two main categories of solar water heating systems: (a) thermosyphon and (b) forced circulation, as shown in Figure 13.6.

Figure 13.6 **Schematic of a Typical Solar Water Heating System Under Thermosyphon and Forced Circulation**



Source: Matias, J. et. al (2011)[13]

Solar water heating systems are very popular in SEE, with millions of installations to be found mostly in Greece, Cyprus, Turkey and Israel, but also in all other countries of SEE. They provide a low cost and reliable way of heating water, while they provide good local manufacturing opportunities.

Solar space heating

Solar energy is successfully used today for the space heating (and cooling) of buildings. There are two types of systems which are available for application mainly in individual houses or small to medium sized commercial buildings. Active systems use mostly flat plate collectors installed on the roof of the buildings, which supply hot water to a central boiler which is usually assisted with oil or gas. The hot water then circulates through the standard radiation panels located in the different rooms. The other system is using solar passive techniques making use of building materials and construction methods to capture solar radiation, convert it into heat and then direct it to the interior of the building, where it is stored in materials with great thermal mass (e.g. concrete, etc.). Depending on the type of application (i.e. attached greenhouse, direct gain, Trombe Wall, etc.) and the thermal mass medium used, solar passive systems could cover a substantial part of space heating requirements. Solar passive systems are ideal for the climatic conditions in most of the geographic area of SE Europe. Their relatively low cost and easy to construct method makes such applications affordable for a large part of the population, mainly outside dense urban areas.

Solar drying

Solar drying has been used for centuries. Drying may be required to preserve agricultural/food products or as a part of the production process, i.e. timber drying. Solar drying systems are those that use the sun's energy more efficiently than simple open-air drying.

Solar distillation

Solar distillation is a solar enhanced distillation process to produce potable water from a saline source. It can be used in areas where drinking water is in short supply but brackish water, i.e. containing dissolved salts, is available. In general, solar distillation equipment, or stills, is more economically attractive for smaller outputs. Costs increase significantly with increased output, in comparison to other technologies which have considerable economics of scale.

Solar cooling

Several forms of technologies are available today for solar-thermally assisted air-conditioning and cooling applications in SE Europe. In particular, for centralized systems providing conditioned air and/or chilled water to buildings, all necessary components are commercially available. The great advantage of this solar application, especially during the hot summer period, is that the daily cooling load

[13] https://www.researchgate.net/publication/284633391_Solar_thermal_system_practical_case_study

profile follows the solar radiation profile (i.e. office buildings), according to UNIDO (2009). In addition to solar assisted centralized systems, we have available passive solar systems which normally apply to individual low size buildings.

Solar concentrating systems (SCS)

Solar concentrating collectors are used to produce high temperatures, which can be used for steam generation and for power production. The temperatures generated by SCS are high enough to produce steam through close circuit systems, which can be used to drive steam turbines generating electricity. There is a wide variety of different designs, some use central receivers, where the solar energy is concentrated to a tower, whilst others use ground based parabolic concentrator systems. SCS technology is not widely used in SEE, but prospects are good in some of countries, such as Greece, Turkey, Cyprus and Israel, which enjoy very high irradiation levels and long sunshine periods on a yearly basis. In connection with SCS, we should note that they offer good opportunities for high local added value in the manufacturing and installation process. Furthermore, solar tower technology is now well developed for several applications and can be cost competitive as it can generate electricity on a 24h basis.

(b) Solar photovoltaic (PV) systems

PV systems convert sunlight directly into electrical energy. The amount of energy that can be produced is directly dependent on the sunshine intensity. Hence, PV systems are capable of producing electricity even in winter and even during cloudy weather albeit at a reduced rate. For that reason, natural cycles in the context of PV systems have three dimensions. As with many other renewable energy technologies, PV has a seasonal variation in potential low cost electricity generation with the peak in summer although in principle PV systems operating along the equator have an almost constant exploitable potential throughout the year. Secondly, electricity generation varies on a daily basis from dawn to dusk peaking during mid-day. Finally, short-term fluctuation of weather conditions, including clouds and rain fall, impact on the inter-hourly amount of electricity that can be harvested. The strengths and weaknesses of this technology are presented in Table 13.4.

Table 13.4 **Strengths and weaknesses of PV energy systems**

Strengths	Weaknesses
Technology is mature. It has high reliability and long lifetimes (power output warranties form PV panels commonly for more than 25 years)	Performance is dependent on sunshine levels and local weather conditions
Automatic operation with very low maintenance requirements	Storage/back-up usually required due to fluctuating nature of sunshine levels/ no power production at night
No fuel required (no additional costs for fuel nor delivery logistics)	High capital/initial investment costs
Modular nature of PV allows for a complete range of system sizes as application dictates	Specific training and infrastructure needs
Environmental impact low compared with conventional energy sources	Energy intensity of silicon production for PV solar cells
The solar system is an easily visible sign of a high level of responsibility, environmental awareness and commitment	Provision for collection of batteries and facilities to recycle batteries are necessary
The user is less affected by rising prices for other energy sources	Use of toxic materials in some PV panels

Source: UNIDO (2009)

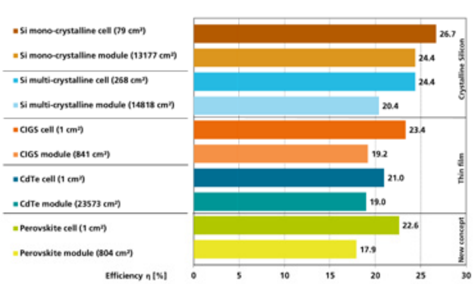
According to UNIDO (2009), PV systems use the chemical-electrical interaction between light radiation and a semiconductor to obtain DC electricity. The base material used to make most types of solar cell is silicon (about 87%). The main PV technologies in use today in SE Europe are:

- Mono-crystalline silicon cells are made of silicon wafers cut from one homogenous crystal in which all silicon atoms are arranged in the same direction. These have a conversion efficiency of 12-15%),
- Poly-crystalline silicon cells are poured and are cheaper and simpler to make than mono-crystalline silicon and the efficiency is lower than that of monocrystalline cells (conversion efficiency 11-14%),

- Thin film solar cells are constructed by depositing extremely thin layer of photovoltaic materials on a low-cost backing such as glass, stainless steel or plastic (conversion efficiency 5-12%),
- Multiple junction cells use two or three layers of different materials in order to improve the efficiency of the module by trying to use a wider spectrum of radiation (conversion efficiency 20-30%).

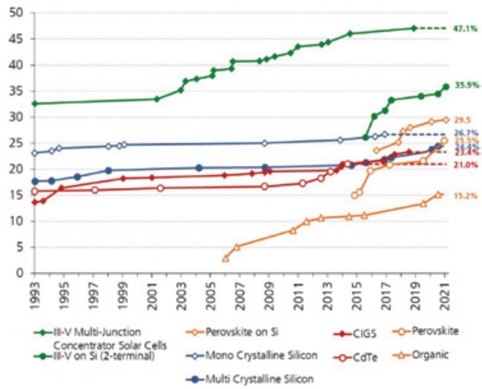
The building block of a PV system is a PV cell. Many PV cells are encapsulated together to form a PV panel or module. A PV array, which is the complete power generation unit, consists of any number of PV modules/panels. Depending on their application, the system will also require major components such as a battery bank and battery controller, DC-AC power inverter, auxiliary energy source etc. Individual PV cells typically have a capacity between 5 and 300 W but systems may have a total installed capacity ranging from 10 W to 100 MW. The very modular nature of PV panels as building blocks to a PV system gives the sizing of systems an important flexibility. Over the last 10-15 years, we have seen significant progress towards improving solar cell and solar module efficiency, with about 21-22% for an average PV panel, almost doubling during this period of time (see Figure 13.8). The average efficiency of most commercial modules is to be found in the range of 20-25% (see Figure 13.9).

Figure 13.7 **Efficiency Comparison of Technologies - Best Lab Cells vs. Best Lab Modules**



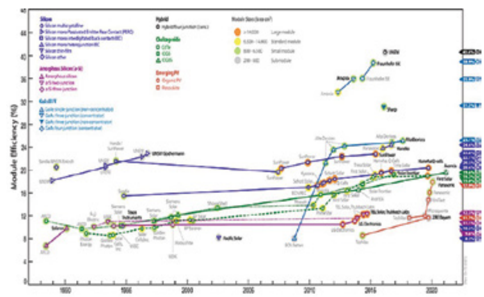
Source: Fraunhofer Institute (2021)[14]

Figure 13.8 **Development of Laboratory Solar Cell Efficiencies**



Source: Fraunhofer Institute (2021)

Figure 13.9 **Solar PV Module Efficiency**



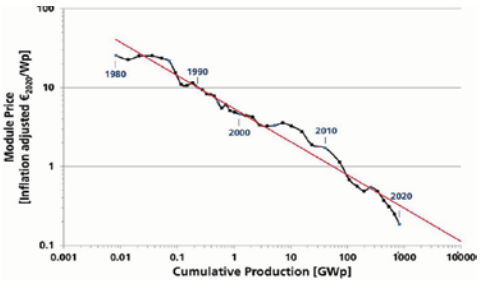
Source: NREL[15]

Historically, module prices have declined as a function of cumulative global shipments. Blue dots in Figure 13.10 represent historical prices and how the module average selling price has decreased over 1976-2015. Red dots depict extrapolated prices for 1TW and 8TW based on the historical trend line.

At the same time, we have witnessed a huge reduction in terms of costs per module, as shown in Figure 13.10. This drop in prices has enabled PV installations to expand remarkably. Today, in SEE, we have several installations in the form of PV parks, above 50 MW, while plans for 200 MW and 300 MW PV parks are now in full swing.

[14] https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf
[15] https://www.nrel.gov/pv/module-efficiency.html

Figure 13.10 **Solar PVs – Impressive Learning Curve Shows No Sign of Abating (Log Scales)**



Source: Fraunhofer Institute (2021)

C. Hydro

Hydropower is the extraction of energy from falling water when it is made to pass through an energy conversion device, such as a water turbine or a water wheel. A water turbine converts the energy of water into mechanical energy, which in turn is often converted into electrical energy by means of a generator. Alternatively, hydropower can also be extracted from river currents when a suitable device is placed directly in a river. The devices employed in this case are generally known as river or water current turbines or a zero head turbine. This module will review only the former type of hydropower, as the latter has a limited potential and application. Table 13.5 illustrates the size classification of hydro power plants.

Table 13,5 **Classification of Hydro-power Size**

Types of hydro	Size
Large-hydro	More than 100 MW and usually feeding into a large electricity grid
Medium-hydro	10 or 20 MW to 100 MW (usually feeding into a grid)
Small-hydro	1 MW to 10 MW or 20 MW (usually feeding into a grid)
Mini-hydro	100 kW to 1 MW (either stand-alone schemes or more often feeding into a grid)
Micro-hydro	5 kW to 100 Kw (usually provide power for a small community or rural industry in remote areas away from the grid)
Pico-hydro	50 W to 5 kW (usually for remote rural communities and individual households. Applications include battery charging or food processing)

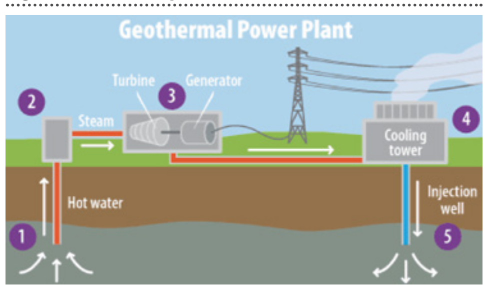
Source: UNIDO (2009)

D. Geothermal

Geothermal is energy available as heat emitted from within the earth, usually in the form of hot water or steam. Geothermal heat has two sources: (a) the original heat produced from the formation of the earth by gravitational collapse and (b) the heat produced by the radioactive decay of various isotopes. It is very site dependent as the resource needs to be near surface and can be used for heating and power generation purposes. High temperature resources (150°C+), known as high enthalpy, can be used for electricity generation, while low temperature resources (50-150°C), known as low enthalpy, can be used for various direct uses such as district heating and industrial processing.

The extraction of energy from geothermal aquifers uses naturally occurring ground water from deep porous rocks. Water can be extracted via a production borehole and, generally be disposed of via an injection hole. Another method is the extraction of heat from hot dry rock (HDR) which uses reservoirs created artificially by hydraulic fracturing. Heat is extracted by circulating water under pressure via production wells.

Figure 13,11 **Description of a Geothermal Power Plant**



Source: US EPA

(i) Deep Geothermal Energy

Direct applications

Direct applications of heat are more widespread in SE Europe as most of the countries use low and medium enthalpy geothermal energy. 9 of the 13 countries of the SE European region use geothermal heat (excluding ground sources heat pumps). The application of ground source heat pumps for space heating and cooling are at the beginning and a limited number of applications of few MWth in the region have been implemented till now.

The applications of geothermal energy in the region vary according to their temperature and include Power generation (t>90°C)

- Space heating (with radiators, t>60°C, fan-coils, t>40°C, floor heating systems, t>25°C)
- Refrigeration and air conditioning (using absorption heat pumps, t>60°C, or with water cooled heat pumps, t<30°C)
- Heating greenhouses and soil because plants grow more quickly and expand with heat (t>25°C), and also for protection from frost.
- Aquaculture (t>15°C) because fish require a specific temperature to grow.
- Industrial applications such as desalination of seawater (t>60°C), drying agricultural products, etc.
- Thermal spas (t = 25-40°C)

The following usages have been addressed by the use of geothermal energy:

- Heating of greenhouses with vegetables and flowers.
- Heating of the root system in open space (e.g. asparangus).
- Heating of fish pools.
- Heating of special pools with algae (Spirulina species) along with a high content of the geothermal water in CO_2.
- Drying of vegetables such as tomatoes, onions, grains, potatoes.
- Drying other material such as wood and fruits, and fishes.
- Regulating the temperature of open fisheries during icing weather in winter.

The geothermal solution was envisaged in areas where both rich in geothermal resources and the agriculture was the main activity of the population. The primary objective was to produce agricultural products out of the season and after that to save money by substituting fossil fuels with free local geothermal heat in areas already having greenhouse production.
There are many technological solutions applied depending on the usage. The simplest one is the use of heat exchangers in covered greenhouses with fans for the circulation of hot air, or with plastic pipes the circulation of hot water. In open air usage the hot water circulates through plastic pipes close to the roots of the plants. In farm fishing usages the heat exchangers are used or even the geothermal water if it does not contain high salts.

Electricity Generation

Geothermal resources vary in temperature from approx. 50°C to 350°C. With dry steam or flash steam, an economical exploitation of the geothermal resource for electricity generation is efficiently and economically possible at temperatures of above 180°C. Moderate-temperature geothermal water between 75°C and 180°C is by far the most common geothermal resource. Common dry steam or flash steam plants cannot efficiently exploit this low and medium temperature resource. The great advantage of power generation from geothermal energy is that they can operate on a 24h basis, providing useful and low-cost base load capacity to the system.
Binary cycle power plants are able to exploit energy from geothermal water with temperature less than 175°C. This system is currently state-of-the-art for electricity production from low and medium temperature geothermal resources. A binary cycle power plant is a type of geothermal power plant that allows cooler geothermal reservoirs to be used than with dry steam and flash steam plants. They are used when the temperature of the water is less than 175°C.

For binary plants two different systems are currently state-of-the-art, the Organic Rankine Cycle (ORC) and the Kalina Cycle:

- In 1961, the first prototype of an Organic Rankine Cycle (ORC) was developed. An ORC uses an organic, high molecular one component mass fluid with a liquid-vapor boiling point, occurring at a lower temperature than the water-steam phase change. The working fluid in a Rankine Cycle is in a closed loop and is circulated and re-used constantly. Lowest possible temperature for ORC heat recovery is about 95°C. With the pilot developed within the Low-Bin project, this temperature was lowered in 78°C.

- The Kalina Cycle, invented by the Russian engineer Alexander Kalina and firstly demonstrated in 1967 in Paratunka, Kamchatka, Russia, is a thermodynamic cycle for converting thermal energy to mechanical power, optimized for use with low to medium temperature geothermal sources. The cycle uses a two component working fluid and a ratio between those components is varied in different parts of the system to increase thermodynamic reversibility and therefore increase overall thermodynamic efficiency. Multiple variants of Kalina cycle systems are specifically applicable for different types of heat sources.

The two systems differ especially in the used working fluid. As ORC uses a one component mass fluid, mostly butane or pentane hydrocarbon, the Kalina cycle uses a working fluid with at least two components (typically water and ammonia) that makes it possible to adjust the ratio between the two components in order to increase the thermodynamic efficiency of the Kalina system. The Kalina system shows higher efficiency in the use of the geothermal resource.

Multipurpose Utilization of Geothermal Fluids

The multipurpose utilization of geothermal fluids was applied since the first days of geothermal uses. In Larderello, the geothermal fluids generated electricity and provided borates as a by-product, since two centuries ago. Today a single use of geothermal energy is rare. It is usual to combine many uses in order to get the very last calorie from the fluid. The most common multiple use is the Combined Heat and Power generation (CHP). When installing a power plant the spent water has a high temperature ranging from 180oC to 80oC. Therefore, it contains enough energy to be used for other purposes. The most obvious is to feed a district heating system as well as some industrial, agricultural and recreational uses and also for Snow Melting and De-icing for transport infrastructures. Sometimes the multipurpose utilization is applied in different seasons of the year according to the heat requirements of each application (for example tomato drying in August and Asparagus greenhouses in spring). There are many such applications worldwide and every new installation tries to make the optimum use of the geothermal fluids available.

Today, it is possible to combine many uses of geothermal energy especially with the high and medium enthalpy fields. In Husavik, Iceland, the medium temperature geothermal fluid (125oC) was at first used for power generation and then it was used in a large number of industrial and agricultural applications. The development of ORC and especially the variation of Kalina cycle allow for the power generation from such low temperature fluids and the technological progress in the material and the insulation of pipes may possible have a minimum of losses in the transportation of lower temperature fluids to big distances and use in many applications.
In a geothermal cogeneration system, the geothermal resource is decoupled for simultaneously using it for electricity-production, heating purposes and direct uses like greenhouses or spas. For direct uses the supplied utilities have to be very close to the plant. The cascading use of energy from high- to low-temperature makes cogeneration more efficient than separate geothermal systems for electricity and heat production. From the viewpoint of optimization of efficiencies combined heat and power (CHP) is optimal.

The geothermal plants for electricity generation can work on several technologies:

- Flash steam plants use hot pressurised water with temperature of above 180°C. The hot water is pumped under great pressure to the surface. When it reaches the surface the pressure decreases to the stage it vaporises. This leads to a two-phase water-steam mixture and a vapour lift process. The steam drives a turbo-alternator for electricity production.
- Dry steam plants use hydrothermal fluids that are primarily steam and emerge at the earth's surface. The steam goes directly to a turbine, which drives a generator that produces electricity.
- Binary plants extract energy from geothermal fluids of about 75°C to 180°C. Hot geothermal fluid and a binary fluid with a much lower boiling

point than the geothermal water pass through a heat exchanger. Heat from the geothermal fluid causes the binary fluid to flash to vapour. The vapour drives the turbines.

A heating system is attached to the electricity generation plant. Part of the geothermal resource is decoupled to the heating plant/system and direct use applications. The different temperatures needed for the direct uses are shown in Figure 13.12.

Figure 13.12 **Applications for Low Temperature Geothermal Resources**

Source: Geo-Heat

Currently, cogeneration is trending towards increased efficiencies in order to optimize the power generation of CHP plants. Moderate-temperature water between 75°C and 180°C is by far the most common geothermal resource. This will lead to the fact that especially in a steadily increasing geothermal technology environment the share of binary cycle plants will increase. The steady improvement of Enhanced Geothermal Systems (EGS) technology is expected to significantly widen the spectrum of geothermal CHP.

Geothermal CHP plants offer the opportunity to combine electricity generation with direct heat applications. The utilization for direct heat applications can be accomplished using the thermal energy available in a waste brine and rejected heat in a condenser to heat fresh water, which can then be distributed to a variety of end users. The technical feasibility and design of such co-generation power plants depend on a number of factors, including the reservoir temperature of the geothermal fluid, the type of flash system used in the power plant, the distance to end users and the types of applications.

The principal technical advantage of geothermal cogeneration systems is their ability to improve the efficiency of geothermal energy use in the production of electrical and thermal energy what improves the economics of the entire system. Many CHP plants, especially those using a low-temperature resource, started as district heating project.

The electric power plant was later added, and became economical, as the well and pumping systems were already in place. Nowadays the CHP is in most cases more profitable and efficient than separate geothermal solutions for electricity generation and direct use.

Desalination and Geothermal Energy

Desalination, desalinization, or **desalinisation** refers to any of several processes that remove excess salt and other minerals from water.

Geothermal desalination is a proven process under development for the production of fresh water using heat energy. Claimed benefits of this method of desalination are that it requires less maintenance than reverse osmosis membranes and that the primary energy input is from geothermal heat, which is a low-environmental-impact source of energy.

The multi stage distillation (MED) powered by geothermal energy was tested and demonstrated in the Kimolos island (Greece) project. It is preferred to lower energy requirement in comparison with other desalination processes. MED method is based on the multi-effect distillation rising film principle at low evaporation temperatures (less than 70oC) due to low, almost vacuum, pressure prevailing in the vessels. The rising effect principle takes advantage of the fact that the inner tube surfaces are always covered by a thin film of feed water that prevents scale formation.

The evaporation through multiple – effect is a very energy efficient technology, as in each vessel the feed water boils utilizing the heat released by condensing vapour from the previous effect. The project did not proceed yet to industrial phase.

Geothermal Industrial Processes

The known industrial applications of geothermal energy can be classified in the following groups:

- Minerals industry (zinc, gold, and industrial minerals and rocks).
- Milk industry
- Mineral water industry
- Oil industry
- Sludge digestion
- Laundries

The main current applications consist of several large operations which dominate the scene followed by a few minor ones. In the minerals industry (zinc and gold, etc.) geothermal energy is used mainly for enhancing the chemical reactions involved in the elements recovery (heating of the cyanide solution in gold recovery) while in the zinc plant there is recovery of the metal from the geothermal fluids which is rich in this metal. The reactions proceed slowly under normal temperatures and the acceleration by geothermal energy increases the metals produced in a given time. In other cases the low winter temperature does not allow the heap leaching of gold and the use of geothermal energy allows all year operations. In some metals cases the high enthalpy geothermal energy is used also for power generation and the waste hot water is used for the ore treatment. All the aforementioned applications are technologically mature and used in industrial level. The use of geothermal energy for zinc and salt production is vital since the geothermal fluids contain the useful commodities. In the other cases the heat of the geothermal fluid is used for the industrial processes involved. The Innovative Character of the technology used in each case has to do with the nature of the heat (a renewable source instead of the classic use of fossil fuels normally used in standard industrial practice).

(ii) Shallow or Low Enthalpy Geothermal

Heat from the ground at a shallow depth, as well as low temperature underground or surface water can be used for heating and air conditioning. This technology involves the use of a very long pipe with a small diameter buried in the ground, or in wells, where it acts as an underground heat exchanger, coupled with a water cooled heat pump which provides heating or cooling to a building. Geothermal heat pumps – or ground source heat pumps, GSHP – are an established technology that it can be used in a wide range of applications, from small, residential houses to large individual buildings or complexes. The average energy savings, if the technology is used properly, are as much as 50% in winter and 40% in summer. They can be installed anywhere and at any time to provide reliable and sustainable renewable energy.

Geothermal heat pumps are covered under both EU's Ecodesign and energy labelling legislation, which are two of the most effective policy tools in the area of energy efficiency. Ecodesign aims to improve the energy and environmental performance of products throughout their life cycle, while energy labelling requirements aim to provide citizens with information about the environmental performance of products and thereby incentivize industry towards the development of further improved products and innovations beyond minimum levels.

E. Bioenergy

Bioenergy refers to energy derived from a wide variety of material of plant or animal origin. This includes fossil fuels but, generally, the term is used to mean renewable energy sources such as wood and wood residues, agricultural crops and residues, animal fats, and animal and human wastes, all of which can yield useful fuels either directly or after some form of conversion. There are technologies for bioenergy using liquid and gaseous fuel, as well as traditional applications of direct combustion. The conversion process can be physical (for instance, drying, size, reduction or densification), thermal (as in carbonization) or chemical (as in biogas production). The end result of the conversion process may be a solid, liquid or gaseous fuel and this flexibility of choice in the physical form of the fuel is one of the advantages of bioenergy over other renewable energy sources. There are numerous commercially available technologies for the conversion processes and for utilization of the end-products. Although the different types of bioenergy have features in common, they exhibit considerable variation in physical and chemical characteristics which influence their use as fuels. Table 13.6 shows examples of bioenergy applications, while Table 13.7 depicts the advantages and disadvantages of bioenergy systems.

Table 13.6 **Examples of Bioenergy Applications**

Fuel state	Application
Biogas	Supplementing mains supply (grid-connected)
Biogas	Cooking and lighting (household-scale digesters), motive power for small industry and electric needs (with gas engine)
Liquid biofuel	Transport fuel and mechanical power, particularly for agriculture; heating and electricity generation; some rural cooking fuel
Solid biomass	Cooking and lighting (direct combustion), motive power for small industry and electric needs (with electric motor)

Source: UNIDO (2009)

Table 13.7 **Strengths and Weaknesses of Bioenergy Systems**

Strengths	Weaknesses
Conversion technologies available in a wide range of power levels at different levels of technological complexity	Production can create land use competition
Fuel production and conversion technology indigenous in developing countries	Often large areas of land are required (usually low energy density)
Production can produce more jobs than other renewable energy systems of a comparable size	Production can have high fertilizer and water requirements
Conversion can be to gaseous, liquid or solid fuel	May require complex management system to ensure constant supply of resource, which is often bulky adding complexity to handling, transport and storage
Environmental impact low (overall no increase in carbon dioxide) compared with conventional energy sources	Resource production may be variable depending on local climatic/weather effects, i.e. drought
	Likely to be uneven resource production throughout the year

Source: UNIDO (2009)

Biogas and Biomethane

According to the IEA[16], **biogas** is a mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment. The precise composition of biogas depends on the type of feedstock and the production pathway; these include the following main technologies:

- **Biodigesters:** These are airtight systems (e.g. containers or tanks) in which organic material, diluted in water, is broken down by naturally occurring micro-organisms. Contaminants and moisture are usually removed prior to use of the biogas.
- **Landfill gas recovery systems:** The decomposition of municipal solid waste (MSW) under anaerobic conditions at landfill sites produces biogas. This can be captured using pipes and extraction wells along with compressors to induce flow to a central collection point.
- **Wastewater treatment plants:** These plants can be equipped to recover organic matter, solids, and nutrients such as nitrogen and phosphorus from sewage sludge. With further treatment, the sewage sludge can be used as an input to produce biogas in an anaerobic digester. The methane content of biogas typically ranges from 45% to 75% by volume, with most of the remainder being CO_2. This variation means that the energy content of biogas can vary; the lower heating value (LHV) is between 16 megajoules per cubic metre (MJ/m^3) and 28 MJ/m^3. Biogas can be used directly to produce electricity and heat or as an energy source for cooking.

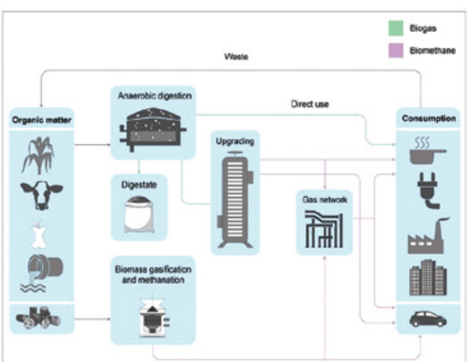
Biomethane is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any CO_2 and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation:

16 IEA (2020), "Outlook for biogas and biomethane – Prospects for organic growth", https://iea.blob.core.windows.net/assets/03aeb10c-c38c-4d10-bcec-de92e9ab815f/Outlook_for_biogas_and_biomethane.pdf

- **Upgrading biogas:** This accounts for around 90% of total biomethane produced worldwide today. Upgrading technologies make use of the different properties of the various gases contained within biogas to separate them, with water scrubbing and membrane separation accounting for almost 60% of biomethane production globally today
- **Thermal gasification of solid biomass followed by methanation**: Woody biomass is first broken down at high temperature (between 700-800°C) and high pressure in a low-oxygen environment. Under these conditions, the biomass is converted into a mixture of gases, mainly carbon monoxide, hydrogen and methane (sometimes collectively called syngas). To produce a pure stream of biomethane, this syngas is cleaned to remove any acidic and corrosive components. The methanation process then uses a catalyst to promote a reaction between the hydrogen and carbon monoxide or CO_2 to produce methane. Any remaining CO_2 or water is removed at the end of this process.

Biomethane has an LHV of around 36 MJ/m^3. It is indistinguishable from natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment, and is fully compatible for use in natural gas vehicles.

Figure 13,13 **Production Pathways for Biogas and Biomethane**



Source: IEA

Europe is the largest producer of biogas today. Germany is by far the largest market, and home to two-thirds of Europe's biogas plant capacity. Energy crops were the primary choice of feedstock that underpinned the growth of Germany's biogas industry, but policy has recently shifted more towards the use of crop residues, sequential crops, livestock waste and the capture of methane from landfill sites. Other countries such as Denmark, France, Italy and the Netherlands have actively promoted biogas production. The biomethane industry is currently very small, although it is generating growing amounts of interest in several countries for its potential to deliver clean energy to a wide array of end users, especially when this can be done using existing infrastructure. Currently, around 3.5 Mtoe of biomethane are produced worldwide, according to the IEA. The vast majority of production lies in European and North American markets, with some countries such as Denmark and Sweden boasting more than 10% shares of biogas/biomethane in total gas sales.

Biomethane, hydrogen and synthetic methane as well as CCUS technologies provide a portfolio of solutions, which will play a significant role in achieving the 2050 objectives in an efficient way. Besides adapting existing generation methods to biomethane, gas infrastructure operators are already investing in various R&D and pilot projects with the intention of developing further renewable gases, energy conversion and – both on transmission and distribution levels into the grid and storage technologies.

F. Energy efficiency and cogeneration

(i) Energy efficiency

A total of $250 billion was invested globally in energy efficiency across the buildings, transport and industry sectors in 2019, almost the same level as the previous year, based on data provided by the IEA's Energy Efficiency 2020 Report[17].

[17] https://iea.blob.core.windows.net/assets/59268647-0b70-4e7b-9f78-269e5ee93f26/Energy_Efficiency_2020.pdf

While there were signs of new activity in some areas, annual changes for each sector remained moderate. The outlook for new efficiency technologies was better, with inflation-adjusted public spending[18] on energy efficiency technology research and development (R&D) for new technologies growing 12% to $4.5 billion, surpassing the previous high of $4.4 billion set in 2009. Energy efficiency was one of the largest targets of total energy-related R&D investment. In contrast to public investment in new technologies, private venture capital funding for startups developing new energy efficiency technologies was less than half of 2018 levels, although the decline was only slight when outlier investments of over $500 million are excluded. Most venture capital was allocated to the buildings sector, with investments spread fairly evenly across different buildings technologies.

Startup investments in heating, ventilation and air-conditioning in 2019 that were under $500 million (i.e. excluding larger outlier deals to avoid skewing trends) were almost double of 2018 levels, an encouraging sign after drops in investment in 2017 and 2018. Innovative cooling technologies targeted for investment in 2019 included technologies for converting waste heat to power refrigeration and air conditioning loops, solar storage cooling technologies, and intelligent devices for improving the efficiency of existing residential air conditioners.

Between 2010 and 2019, startups in the United States have been the largest recipients for efficiency-related venture capital, receiving around 70% of investments, whereas businesses based in the European Union received around 16% of investments and Chinese businesses another 7%. Technologies targeted for investment in these three major regions partly reflect each region's comparative advantages. For example, in the United States, home to Silicon Valley, investments in IT and data centre energy efficiency have been strong. Europe is fast catching up with emphasis placed in electronic control systems, innovative heat pumps and rooftop photovoltaics.

Buildings

Under the IEA Sustainable Development Scenario, the energy used per square metre of building floor area is set to decrease globally by at least 2.5% per year on average. This could be achieved by 2030 with more efficient new buildings, deep energy renovations of existing buildings, a tripling of heat pump uptake and a 50% improvement in the average seasonal performance of air conditioners, as well as other energy efficiency measures. Alongside these technologies, digital systems, such as intelligent building energy management systems and smart controls, continue to be deployed to great effect but have yet to achieve widespread adoption. Only lighting and data centres are currently on track.

Table 13.8 **Clean Energy Technology Progress for Key Buildings Sector Technologies**

Technology	2019 Status	Status compared with 2018
Building envelopes	●	-
Heating	●	-
Heat pumps	●	↑
Cooling	●	-
Lighting	●	-
Appliances and equipment	●	-
Data centres and data transmission networks	●	-

Source: IEA

The buildings sector is still the largest destination of efficiency spending. After faltering in 2018 in response to reduced government support in Europe, it grew 2% in 2019 to just over $150 billion, thanks mostly to increased investments in emerging economies. A two-speed market appears to be developing, with stronger activity in emerging economies where new construction is taking place, especially China, and weaker markets in Europe and North America, where a greater share of investment is driven by retrofits. Improvement in the energy efficiency of buildings is attracting growing attention in SE Europe, backed by EU funds, with a good choice of tested technologies, such as heat pumps, electronic control mechanisms, thermal insulation, double or triple glazing, solar water heaters and rooftop photovoltaics.

[18] This spending is additional to the $250 billion investment cited above.

A number of innovative schemes are being tested in various countries in the region, focusing on geothermal powered heat pumps, combined solar water heaters and photovoltaic panels for domestic applications, clever solar shading devices and improved thermal insulation systems.

Transport

According to the IEA's database, electric car sales reached 2.1 million in 2019, securing their highest ever share (2.6%) of the global car sales market. The number of electric cars on the world's roads exceeded 7 million in 2019. Fleets of electric buses and trucks are also being procured in more and more cities around the world, including various capitals in SE Europe. The global appetite for larger vehicles like SUVs continued, however. This trend is common to all vehicle markets and has led to a slackening – or in some cases even reversal – of national rates of fuel consumption improvements. Globally, high-speed rail continues to grow strongly. Almost two out of three high-speed rail lines are in China: starting from virtually none only a decade ago, the country now has over 24,000 km. In 2019 alone, China National Railways opened two more high-speed rail corridors totalling 750 km of lines, and added more than 3,000 km of new lines. The rapidity of this rollout makes it one of the largest infrastructure projects in recent history. Total high-speed rail activity in China is catching up with domestic passenger aviation. This is significantly boosting transport energy efficiency, because rail is more energy efficient than road and air travel.

Table 13.9 **Clean Energy Technology Progress for Key Transport Sub-sectors**

Transport sub-sector	2019 status	Status compared with 2018
Electric vehicles	🟢	-
Rail	🟢	-
Fuel consumption of cars and vans	🔴	-
Trucks and buses	🟡	-
Aviation	🟡	-
International shipping	🟡	-

Source: IEA

Transport efficiency investment fell slightly in 2019 (by nearly 4%), as global car sales fell and sales of the most efficient cars trailed the wider market. Spending on more efficient road freight vehicles stabilised despite a drop in the overall market – including a decline in total sales in China – as fuel economy standards began to make an impact. Freight vehicles generally have higher upfront costs, making purchases hard to justify for smaller enterprises, despite lower lifetime fuel costs.

Industry

As rapid urbanisation continued, demand for construction materials, such as steel and cement, remained strong in 2019. These two sectors alone represented almost 30% of industrial energy use and more than 41% of industrial sector's greenhouse gas emissions. In these and other energy-intensive industrial sub-sectors, energy efficiency technologies are not being deployed at levels modelled in the IEA Sustainable Development Scenario. In 2019, there were no major technological changes in the status of clean energy technology progress within major energy-consuming industries.

Table 13.10 **Clean Energy Technology Progress for Key Industry Sub-sectors**

Industry sub-sector	2019 status	Status compared with 2018
Chemicals	🟡	-
Iron and steel	🟡	-
Cement	🟡	-
Pulp and paper	🟡	-
Aluminium	🟡	-

Source: IEA

The use of scrap steel in either electric arc furnaces or induction furnaces is one of the most effective ways of reducing the energy intensity of steel production. To meet the Sustainable Development Scenario, scrap inputs should account for over 40% of total crude steel production by 2030. In 2018, the rate of scrap-based production was only about 20%. It is unlikely that scrap use increased in 2019, as the share of crude steel produced by electric arc furnaces (which use scrap as a primary feedstock) declined from 28.8% in 2018 to 27.7% in 2019.

Energy efficiency improvements in global aluminium production differed by region and stage in the production process. Globally, the energy intensity of aluminium smelting stayed almost flat, at just over 14,000 kWh per tonne of aluminium. In contrast, global alumina refining (the process of refining bauxite ore into alumina) was over 5% less energy intensive, mainly due to Chinese producers adopting best available technologies, based on IEA's data. However, improving energy efficiency in both alumina and aluminium production processes is of special interest to SE Europe as a number of such plants are operating in Greece, Montenegro, etc. Already, a number of effective energy efficiency improvement measures have been introduced in the above plants, including the introduction of higher efficiency furnaces and electricity cogeneration schemes.

Energy management systems are among the most cost effective ways to promote energy efficiency across industrial sub-sectors. Each year, the number of industrial facilities certified by the International Organization for Standardization (ISO) as complying with the international standard for energy management (ISO 50001) provides an indicator of the prevalence of such systems globally. Key drivers have been government incentives or regulations, changing values and sustainability goals of companies and non-energy benefits, which can be crucial for small and medium-sized enterprises. However, barriers to wider uptake still exist, such as firms lacking a culture of energy management, a fear of extra administrative complexity, and skills shortages.

The number of ISO 50001 certifications decreased in Germany in 2019 and stayed almost flat in France, Italy, Spain and the United Kingdom. The number of certifications and certified sites increased in emerging economies, such as China and India, but the total number of certifications in these regions is still less than half that of Europe. The net result is that globally the number of ISO 50001 certifications has stagnated in the last two years. Certificates in Africa are dominated by Egypt (with almost two-thirds of certifications, mostly in light industry). In the Americas, Brazil and Mexico represent almost half of certifications, while China and India represent almost 90% of certificates in Asia. In Europe, the trend is a preference for multi-site certifications, with on average almost three sites per certification in Germany and four in France, Italy, Spain and the United Kingdom. The trend does not appear to be growing China and India, however. Opting for multi-site certifications may be a way to reduce the administrative burden[19], while still complying with regulations and accessing incentives, the IEA adds.

In SE Europe, energy efficiency projects in the buildings, transport and industry sectors are constantly increasing. Finding financially viable solutions is an important priority, particularly for SEE, but the upfront costs of energy efficiency measures is not negligible and attracting private investments in energy efficiency is hampered by numerous well-known difficulties and market failures. Many barriers have been overcome in a number of instances through specialised investment instruments, but there is no 'one size fits all' solution and many instruments are context-specific. However, there are numerous investment opportunities in SEE concerning energy efficiency projects through various International Financial Institutions, such as EBRD, World Bank, EIB, the European Fund for Southeast Europe, etc.

(ii) Cogeneration

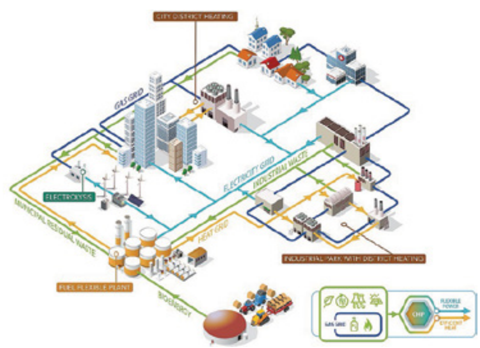
Cogeneration is a very efficient technology to generate electricity and heat. It is also called Combined Heat and Power (CHP) as cogeneration produces heat and electricity simultaneously. Cogeneration supplies currently 11% of electricity and 15% of heat in Europe. Using a fuel to simultaneously generate heat and electricity with a single unit is more efficient and cost-effective than generating heat and electricity separately in two different units.

[19] Multi-site certifications are based on a sample of sites that are audited, thereby reducing the number of audit days for a company.

The European Green Deal promises to deliver on a net-zero energy system by 2050, through higher ambition on energy efficiency, system integration and renewable energy. A study by Artelys[20] finds that cogeneration is a primary enabler to achieve carbon neutrality in Europe by 2050. More specifically, the study finds that there is cost-effective potential for cogeneration as a key solution in a highly electrified, highly renewable and low demand net zero emissions energy system. When considering higher shares of bioenergy sources, cogeneration uptake is even more relevant fostering the efficient use of these fuels. Optimising cogeneration as part of integrated energy systems leads to energy system cost reduction of €4.1-€8.2 billion and allows to reduce CO_2 emissions by 4-5 $MtCO_2$ annually.

Cogeneration will displace less efficient power-only and heat-only generation, contributing 13-16% of total power and 19-27% of total heat production in 2050. Optimised cogeneration will operate flexibly and efficiently when and where needed, especially at times of peak demand by heat pumps and electrical vehicles and insufficient wind speeds and solar radiation.

Figure 13.14 **Cogeneration in Climate Neutral Energy System**



Source: COGEN Europe

In SE Europe, cogeneration is varying, as there are countries without or with limited installed cogeneration capacity, mainly for residential and industrial purposes.

However, there is a high potential for its development over the next decade, as clean technologies can play a vital role in the energy transition process.

G. Hydrogen

Hydrogen is a versatile energy carrier, which can help to tackle various critical energy challenges. Hydrogen can be produced from almost all energy resources, though today's use of hydrogen in oil refining and chemical production is mostly covered by hydrogen from fossil fuels, with significant associated CO_2 emissions.

Clean hydrogen, being produced from renewables, nuclear or fossil fuels with CCUS, can help to decarbonise a range of sectors, including long-haul transport, chemicals, iron and steel, where it is proven difficult to reduce emissions. Hydrogen can also help to improve air quality in cities and improve energy security. Hydrogen can also support the integration of variable renewables in the electricity system, being one of the very few options for storing electricity over days, weeks or months. Today hydrogen is mainly used in the refining and chemical sectors and produced from fossils, accounting for 6% of global natural gas use and 2% of coal consumption and being responsible for 830 $MtCO_2$ of annual CO_2 emissions. Scale-up will be critical to bring down the costs of technologies for producing and using clean hydrogen, such as electrolysers, fuel cells and hydrogen production with CCUS.

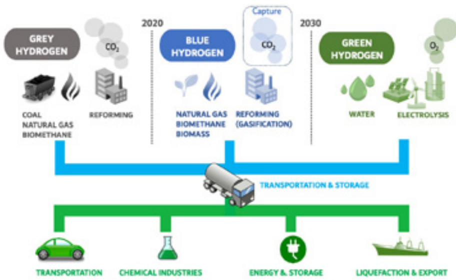
Supplying hydrogen to industrial users is now a major business around the world. Demand for hydrogen, which has grown more than threefold since 1975, continues to rise – almost entirely supplied from fossil fuels, with 6% of global natural gas and 2% of global coal going to hydrogen production. As a consequence, production of hydrogen is responsible for CO_2 emissions of around 830 million tonnes of carbon dioxide per year, equivalent to the CO_2 emissions of the United Kingdom and Indonesia combined.

[20] https://www.cogeneurope.eu/images/Artelys-Presentation-Key-Findings---Study-Commissioned-by-CE-final.pdf

The EU's strategy[21], presented in July 2020, calls for setting up an electrolyzer fleet of total capacity between 5 GW and 6 GW by 2025, and then another 40 GW by 2030. The strategy aims to promote primarily hydrogen from RES, the so-called green hydrogen. Blue hydrogen, produced from natural gas, is addressed to a lesser degree. It requires capturing and storing carbon dioxide. Also mentioned is the pyrolisis of methane directly into hydrogen and carbon.

There is no doubt that green hydrogen production is the biggest challenge for European industry, including SEE. However, projects for the production and use of green hydrogen are still more political than economic. The projects aim to create a green hydrogen value chain connecting the RES capacities in SE Europe with the growing interest in hydrogen in Western Europe. Recently announced investments in (SE) Europe will undoubtedly give a strong impetus to the technologies for hydrogen production, storage and transport, as well as for its conversion back to energy.

Figure 13.15 **The Three Colors of Hydrogen**



Source: Chem.4.us [22]

For instance, in Greece, there is the White Dragon project that provides investments of €2.5 billion in electrolytic hydrogen production by means of solar energy from photovoltaic parks with a capacity of 1.5 GW to be installed in Western Macedonia in the context of the region's decarbonization programme. The Regional Authority of Western Macedonia is coordinating the project and its members include the Public Gas Corporation (DEPA), gas grid operator DESFA, Hellenic Petroleum, Motor Oil, Mytilineos, Terna, Polish company Solaris, the Demokritos National Center for Scientific Research and the Center for Research and Technology Hellas (CERTH). The hydrogen produced will be used for district heating, as fuel to be exported via the TAP gas pipeline, and as fuel for large vehicles, such as lorries, buses, etc.

The aim of the EU member states of SE Europe is to meet their targets for hydrogen deployment, according to their NECPs, provided they have set up such targets. In the case of the Western Balkans' countries that are not EU member states, the main goal today is to develop a hydrogen strategy. Among others, a good hydrogen strategy could reduce the share of coal/lignite in the regional energy mix and cut GHG emissions. In addition, several projects for the sustainable production of both green and blue hydrogen should be promoted and the majority, if not all, of the SEE countries should join in. It remains to be seen if the SEE region will understand the importance of hydrogen over the next years or it will lag behind developments in Western and Central Europe.

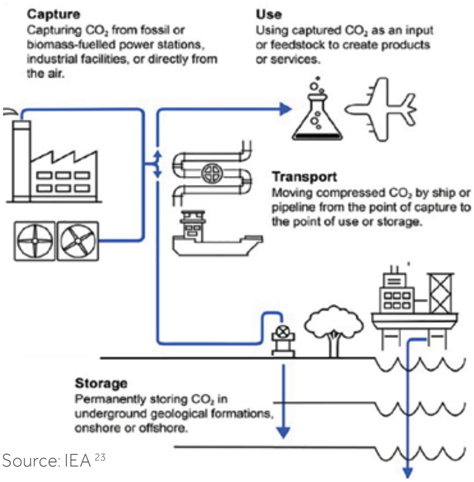
H. Carbon Capture, Utilisation and Storage (CCUS)

CCUS refers to a suite of technologies that involves the capture of CO_2 from large point sources, including power generation or industrial facilities that use either fossil fuels or biomass for fuel. The CO_2 can also be captured directly from the atmosphere. If not being used on-site, the captured CO_2 is compressed and transported by pipeline, ship, rail or truck to be used in a range of applications, or injected into deep geological formations (including depleted oil and gas reservoirs or saline formations) which trap the CO_2 for permanent storage.

The extent to which CO_2 emissions are reduced in net terms depends on how much of the CO_2 is captured from the point source and whether and how the CO_2 is used.

[21] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
[22] http://www.chem4us.be/blue-green-gray-the-colors-of-hydrogen/

Figure 13.16 **The CCUS Technology**



Source: IEA [23]

The use of the CO_2 for an industrial purpose can provide a potential revenue stream for CCUS facilities. Until now, the vast majority of CCUS projects have relied on revenue from the sale of CO_2 to oil companies for enhanced oil recovery (EOR), but there are many other potential uses of the CO_2, including as a feedstock for the production of synthetic fuels, chemicals and building materials. CCUS technologies can provide a means of removing CO_2 from the atmosphere, i.e. "negative emissions", to offset emissions from sectors where reaching zero emissions may not be not economically or technically feasible. Bioenergy with carbon capture and storage (BECCS) involves capturing and permanently storing CO_2 from processes where biomass (which extracts CO_2 from the atmosphere as it grows) is burned to generate energy. A power station fuelled with biomass and equipped with CCUS is a type of BECCS technology. Direct air capture (DAC) involves the capture of CO_2 directly from ambient air (as opposed to a point source). The CO_2 can be used, for example, as a CO_2 feedstock in synthetic fuels, or it can be permanently stored to achieve negative emissions. These technology-based approaches for carbon removal can complement and supplement nature-based solutions, such as afforestation and reforestation.

Table 13.11 **Principal CO_2 Capture Technologies**

Capture Technology	Overview	Technology status
Chemical absorption	A common process operation based on the reaction between CO_2 and a chemical solvent (such as compounds of ethanolamine). Chemical absorption using amine-based solvents is the most advanced CO_2 separation technique.	Widely used for decades and currently applied in a number of small and large-scale projects worldwide in power generation, fuel transformation and industrial production.
Physical separation	Based on either adsorption, absorption, cryogenic separation, or dehydration and compression. Physical adsorption makes use of a solid surface (e.g. activated carbon, alumina, metallic oxides or zeolites), while physical absorption makes use of a liquid solvent (e.g. Selexol or Rectisol). After capture by means of an adsorbent, CO_2 is released by increasing temperature (temperature swing adsorption) or pressure (pressure swing adsorption or vacuum swing adsorption).	Currently used mainly in natural gas processing and ethanol, methanol and hydrogen production, with nine commercial plants in operation.
Oxy-fuel separation	Involves the combustion of a fuel using nearly pure oxygen and the subsequent capture of the CO_2 emitted. Because the flue gas is composed almost exclusively of CO_2 and water vapour, the latter can be removed easily by means of dehydration to obtain a high-purity CO_2 stream.	Currently at the large prototype/ pre-demonstration stage. A number of projects have been completed in coal-based power generation and in cement production.
Membrane separation	Based on polymeric or inorganic devices (membranes) with high CO_2 selectivity, which let CO_2 pass through but act as barriers to retain the other gases in the gas stream.	Technology readiness varies according to the fuel and application. In natural gas processing, it is mainly at the demonstration stage. The only existing large-scale capture plant based on membrane separation is operated by Petrobras in Brazil. Membranes for CO_2 removal from syngas and biogas are already commercially available, while membranes for flue gas treatment are currently under development.
Calcium looping	Involves CO_2 capture at a high temperature using two main reactors. In the first reactor, lime (CaO) is used as a sorbent to capture CO_2 from a gas stream to form calcium carbonate (CaCO3). The CaCO3 is subsequently transported to the second reactor where it is regenerated, resulting in lime and a pure stream of CO_2. The lime is then looped back to the first reactor.	Currently at a pilot / pre-commercial stage. It has been tested for example in coal-fired fluidised bed combustors and cement manufacture
Chemical looping	Like calcium looping, a two-reactor technology. In the first reactor, small particles of metal (e.g. iron or manganese) are used to bind oxygen from the air to form a metal oxide, which is then transported to the second reactor where it reacts with fuel, producing energy and a concentrated stream of CO_2, regenerating the reduced form of the metal. The metal is then looped back to the first reactor.	This technology has been tested through the operation of around 35 pilot projects with coal, gas, oil and biomass combustion.
Direct separation	Involves the capture of CO_2 process emissions from cement production by indirectly heating the limestone using a special calciner. This technology strips CO_2 directly from the limestone, without mixing it with other combustion gases, thus considerably reducing energy costs related to gas separation.	Currently being tested at pilot projects such as the Low Emissions Intensity Lime and Cement (LEILAC) pilot plant developed by Calix at the HeidelbergCement plant in Lixhe, Belgium.

Source: IEA [24]

[23] IEA (2020), "Energy Technology Perspectives 2020 – Special Report on Carbon Capture Utilisation and Storage", https://webstore.iea.org/ccus-in-clean-energy-transitions

[24] IEA (2020), "Energy Technology Perspectives 2020 – Special Report on Carbon Capture Utilisation and Storage", https://webstore.iea.org/ccus-in-clean-energy-transitions

CO_2 can be captured from a range of sources, including the air, and transported by pipeline or ship for use or permanent storage. Different terminology is often adopted when discussing CCUS technologies:

- Carbon capture and storage (CCS): includes applications where the CO_2 is captured and permanently stored
- Carbon capture and utilisation (CCU) or CO_2 use: includes where the CO_2 is used, for example in the production of fuels and chemicals

Carbon capture, utilisation and storage (CCUS): includes CCS, CCU and also where the CO_2 is both used and stored, for example in EOR or in building materials, where the use results in some or all of the CO_2 being permanently stored.

Global current status of CCUS in power generation

Currently, two large-scale CCUS facilities operate in the power sector globally, the Petra Nova Carbon Capture project in the United States and the Boundary Dam Carbon Capture project in Canada, which are both CCUS retrofits to existing coal-fired power plants. At 240 MW, the Petra Nova project in Texas, which has been operating successfully since 2017, is the largest post-combustion carbon capture system installed on a coal-fired power plant. It captures up to 1.4 Mt CO_2 annually for use in EOR, which uses injected CO_2 to reverse the decline in production of mature oil fields and to increase overall extraction.

In December 2019, J-Power began testing at its Osaki CoolGen Capture demonstration project in Japan, capturing CO_2 from a 166 MW integrated gasification combined-cycle plant, enlarging the portfolio of capture technologies at operational coal-fired power plants.

Progress on bioenergy in combination with carbon capture has accelerated with Drax's BECCS pilot project in the United Kingdom, a world-first demonstration capturing CO_2 from a power plant fuelled by 100% biomass feedstock. The first pilot commenced capture operations in early 2019 (1 tCO_2/day) and a second pilot project was announced in June 2020, set to capture 0.3 tCO_2/day from Q3 2020. If the project proceeds to a full-scale operation, it could become the world's first negative emissions power station[25]. While there are currently no large-scale CCUS gas-fired plants operating, the Oil and Gas Climate Initiative[26] recently announced that a partnership involving several of its member companies will undertake a front-end engineering and design (FEED) study on a gas-fired power plant in the United Kingdom.

Separately, the NET Power 50 MWth clean energy plant in Texas is a first-of-its-kind gas-fired power plant employing Allam cycle technology, which aims to use CO_2 as a working fluid in an oxyfuel supercritical CO_2 power cycle. The NET Power demonstration project started operations in 2018. According to the developers, NET Power could make zero-emissions gas-fired power generation competitive with existing power generation technologies.

Map 13.2 **Global Current CCUS Projects**

Source: IEA and GCCSI (2021) [27]

[25] Drax (2019), "Carbon dioxide now being captured in first of its kind BECCS pilot", https://www.drax.com/press_release/world-first-co2-beccs-ccus/ and
Drax (2020), "Negative emissions pioneer Drax and leading global carbon capture company – Mitsubishi Heavy Industries Group – announce new BECCS pilot", https://www.drax.com/press_release/negative-emissions-pioneer-drax-and-leading-global-carbon-capture-company-mitsubishi-heavy-industries-group-announce-new-beccs-pilot/

[26] https://oilandgasclimateinitiative.com/climate-investments/investment-portfolio/net-zero-teesside/

[27] IEA research and GCCSI (2021), Facilities Database, https://co2re.co/FacilityData

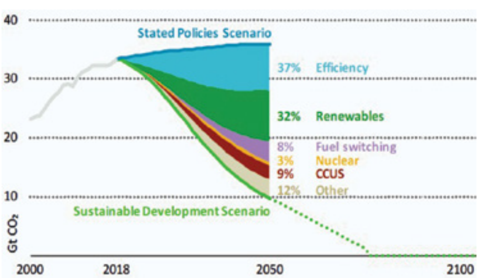
Twenty CCUS power generation projects are currently under development. Eleven of them are in the United States; three are in China and the United Kingdom, respectively, as well as one each in Ireland, Korea and the Netherlands. Seven of the projects in development relate to gas-fired power: one involves converting a gas-fired plant to hydrogen, two relate to biomass and waste-based power generation, and the remainder plan to apply CCUS to existing or new coal-fired power plants.

The two large-scale CCUS power projects operational today and the 20 in development have a potential combined capture capacity of more than 50 MtCO_2 per year. This compares to around 310 MtCO_2 captured from power generation in 2030 in the IEA Sustainable Development Scenario, reflecting that carbon capture, utilisation and storage in power generation is not currently on course.

CCUS technologies to play an important role in CO_2 emission reduction

In IEA's Sustainable Development Scenario (SDS), CCUS plays an important role in terms of decreased emissions. According to SDS, the application of CCUS technologies can help decrease CO_2 emissions by 9.0% by 2050.

Figure 13.17 **The CCUS Technology**



Source: IEA[28]

As the IEA notes in its 2019 World Energy Outlook report[29], "thanks to efficiency improvements, electrification and fuel switching, energy demand remains broadly stable, despite a growing global economy. However, the fuel mix changes dramatically. Electricity demand grows steadily in the Sustainable Development Scenario, as mobility and heating are electrified. By 2040, wind and solar become the top two sources of power generation and by 2050 the power sector is mostly decarbonised. Electric cars make up three-quarters of all cars sold. Hydrogen and biomethane are used in gas grids. Energy efficiency, material efficiency and CCUS together decarbonize heavy industries. A host of new low-carbon technologies move from low market shares to wide deployment at a speed as fast as anything in the history of the energy sector."

Undoubtedly, there is a large potential for the implementation of CCUS in SE Europe, as the energy mix of almost all of the SE European countries is relied on coal/lignite. For instance, in Greece, captured CO_2 is delivered in high purity, allowing for potential utilization in various applications, such as fuel, chemical products and concrete building materials. Currently, Western Macedonia has limited potential to utilise the CO_2 produced. Other industrial users are located in other parts of Greece, as shown in Table 13.12.

Table 13.12 **Potential Greek Industries Available for CO_2 Utilisation**

Industrial Sector for CO_2 Utilisation	Number of Industries in Greece			
	North	Central	South	Total
Building materials	7	7	-	14
Refineries (synthetic fuels)	1	3	-	4
Yield boosting (greenhouses, urea, fertilisers)	1	-	1	2
Chemicals industry (plastic, resins, foams)	5	-	1	6
Other (e.g., ink, aluminum)	1	2	-	3

Source: Koukouzas, N. et al. (2021)[30]

The region of Prinos (South Kavala, Northern Greece) can serve as a potential site for high capacity and cost-effective CO_2-storage. Estimations indicate that the offshore Prinos basin has a storage capacity of 30 Mt CO_2 within the oil reservoirs and 1,350 Mt CO_2 within

28 IEA (2019), "World Energy Outlook 2019", https://webstore.iea.org/world-energy-outlook-2019
29 IEA (2019), "World Energy Outlook 2019", https://webstore.iea.org/world-energy-outlook-2019
30 Koukouzas, N. et al. (2021), "Carbon Capture, Utilisation and Storage as a Defense Tool against Climate Change: Current Developments in West Macedonia (Greece)", Energies 2021, 14, 3321, https://doi.org/10.3390/en14113321

the 2.4 km depth saline aquifers[31]. In the same region, the Miocene sandstones, which are located at ~1600 m depth provide an additional option for the implementation of CO_2-storage technologies with a capacity of 35 Mt CO_2. The Prinos oil and gas field holds the potential to combine CO_2-storage with underground gas storage (UGS) technologies. Research studies suggest that the Prinos oil-field is amongst the most promising sites for UGS in Greece, presenting a total gas volume and energy storage capacity of 2,280 mm3 and 4,826,105 MWh[e] respectively[32]. The Prinos oil fields can provide secure and cost-effective site for CO_2-EOR due to its-reservoir properties, the short distance from the mainland, as well as the presence of existing infrastructures. The aforementioned indicate that the region of Prinos provides significant advantages for safe long-term and cost-effective storage scenarios, according to Koukouzas et al. (2021). It is worth noting that Energian Plc plans to develop in Greece the first CO_2-storage/small-scale hydrogen plant in Mediterranean close to the Prinos oil-field, with a capital expenditure of about $500 million[33].

I. Electric Vehicles

With over 2% of global car sales, the electric car fleet is expanding quickly, according to the IEA[34]. Ambitious policy announcements have been critical in stimulating the electric mobility transition in major vehicle markets. Policies have major influences on the development of electric mobility. Policy approaches to promote the deployment of EVs typically start with a vision statement and a set of targets. An initial step is the adoption of electric vehicle and charging standards.

Economic incentives and regulatory measures are often coupled with other policies that increase the value proposition of EVs. Such policies often aim to harness the multiple co-benefits arising from greater electrification of transport, most prominently energy diversification in a sector that is 90% dependent on oil products and the reduction of local pollutant and GHG emissions. Measures that provide crucial incentives to scale up the availability of vehicles with low and zero tailpipe emissions include fuel economy standards, zero-emission vehicle mandates and the rise in the ambition of public procurement programmes.

Regulatory measures related to charging infrastructure include minimum requirements to ensure "EV readiness" in new or refurbished buildings and parking lots, deployment of publicly accessible chargers in cities and on highway networks, and are complemented by requirements regarding inter-operability and minimum availability levels for publicly accessible charging infrastructure.

Vehicle manufacturers and policy makers are boosting their attention and actions related to electric vehicles (EVs). EV technologies, such as full battery electric and plug-in hybrid electric models, are attractive options to help reach environmental, societal and health objectives. In addition to being two- to four-times more efficient than conventional internal combustion engine models, EVs can reduce reliance on oil-based fuels and, if running on low-carbon power, can deliver significant reductions in greenhouse gas emissions. Plus, with zero tailpipe emissions, EVs are well suited to help solve air pollution issues. Moreover, EVs are driving advances in battery technology – a key issue for industrial competitiveness in the transition to clean energy.

EV fleets are expanding at a fast pace in several of the world's largest vehicle markets. The costs of batteries and EVs are dropping. Charging infrastructure is expanding. This progress promotes electrification of transport

[31] Arvanitis, A. et al. (2019), "Combined CO2 Geological Storage and Geothermal Energy Utilization in Greece", Bulletin of the Geological Society of Greece, pp. 539-540.
[32] Arvanitis, A. et al. (2020), "Potential Sites for Underground Energy and CO2 Storage in Greece: A Geological and Petrological Approach", Energies, 13, pp. 2707.
[33] Tugwell, P. (2021), "Energean Plans $500 Million Carbon Storage and H2 Facility", Bloomberg, https://www.bloomberg.com/news/articles/2021-02-25/energean-plans-500-million-greek-carbon-storage-and-h2-facility
[34] https://www.iea.org/fuels-and-technologies/electric-vehicles

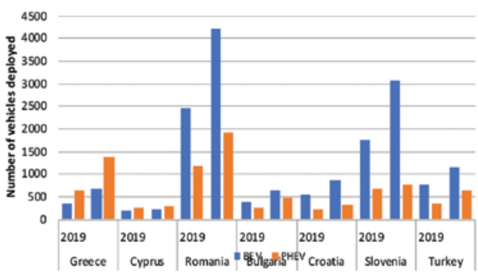
modes such as two/three-wheelers, light-duty vehicles (LDVs) (cars and vans), taxis and shared vehicles, buses and heavy-duty vehicles with short range requirements such as urban deliveries. Manufacturers are continuing to expand the number of EV models available to customers. Effective policies still needed to address upfront investment costs, promote EV charging infrastructure and ensure a smooth integration of charging demand in power systems. With foundations being laid for widespread adoption of EVs in several large economies, there are strong prospects that the 2020s will be the decade in which electric mobility significantly expands.

Currently, the development of electric vehicles in SE Europe is at a nascent level, but it is expected to grow over the next decades. In this context, there are several actions that are already ongoing such as the European project "Comprehensive fast-charging corridor network in SE Europe"[35].

This Action is the second phase of a Global Project aiming at deploying and operating a comprehensive multi-standard, open-access fast and ultra-fast charging corridor for electric vehicles in SE Europe. The Action will contribute to the implementation of National Action Plans for the deployment of alternative fuels infrastructure. The objective is to set up a multi-standard open-access fast charging network in Croatia and Romania. It covers 3 TEN-T corridors, namely the Mediterranean, Rhine-Danube and the Orient/East-Med Core Network corridors. During the Action, 69 multi-standard fast charging stations (50 kW DC and 22 Kw AC) will be deployed, 53 in Romania at 25 sites and 16 in Croatia at 6 sites. Furthermore, 4 ultra-fast charging stations (minimum 150 kW DC) will be deployed, 3 in Romania and 1 in Croatia. Charging stations will be powered by energy from renewable sources, such as wind or solar power.

Based on data from the European Alternative Fuels Obervatory (EAFO)[36], the automotive industry of the SE European region, mainly located in Turkey, Romania and Slovenia, has not yet made a significant turn in EV manufacturing. Figure 13.18 shows the number of Plug-in Electric Vehicles (PEVs), including BEVs and PHEVs, in selected SEE countries for 2019 and 2020, highlighting the nascent stage of their development. Indicatively, the total number of PEVs in SE Europe stood at 10,049 in 2019, when the total number of PEVs reached 1.75 million in Europe over the same year and exceeded 7.1 million globally, as analysed in IENE's Monthly Analysis of December 2020-January 2021[37].

Figure 13.18 **PEV Fleet in Selected SEE Countries, 2019 and 2020***



Note: *Data available until October 2020
Source: EAFO

In addition, the market share of PEVs in the selected SE European countries, as shown in Figure 13.19, averaged 0.54% in 2019, which is low, compared to European and global levels. More specifically, the 2.6% market share of PEVs in global car sales constituted a record in 2019. In particular, China (at 4.9%) and Europe (at 3.5%) achieved new records in EV market share in 2019.

Most notably, regional markets with more developed EV charging network, such as Slovenia and Croatia, have seen a higher penetration of BEVs to their motor vehicle market. On the contrary, markets, such as

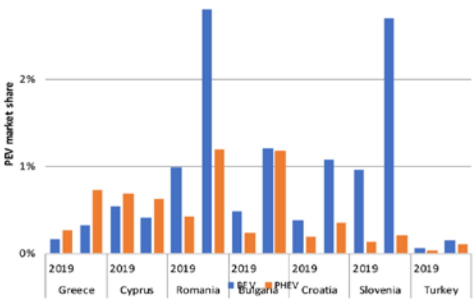
[35] European Commission (2020), "Comprehensive fast-charging corridor network in South East Europe", https://trimis.ec.europa.eu/project/comprehensive-fast-charging-corridor-network-south-east-europe

[36] https://www.eafo.eu/countries/european-union/23640/summary

[37] IENE (2021), "Global Current and Future Status of EVs: The Case of SE Europe", Issue No 325

Greece and Cyprus, which exhibit delays in the deployment of adequate EV charging infrastructure, have a more developed market for PHEVs. Currently, based on data for 2019 and 2020 (Jan-Oct), the regional market size for PHEVs stands at approximately 50% of the market size of BEVs. Furthermore, 2020 has been a significant year for the sales of EVs in SE Europe, as the regional fleet rose by 65.4% during the period of January-October.

Figure 13.19 **PEV Market Share (%) in Selected SEE Countries, 2019 and 2020***



Note: *Data available until October 2020
Source: EAFO

J. Energy Storage

(a) Batteries and electricity storage for electromobility

Technology costs for battery storage continue to drop quickly, largely owing to the rapid scale-up of battery manufacturing for electric vehicles, stimulating deployment in the power sector. Storage is one of a suite of options to provide energy system flexibility, and it can generally be deployed quickly and modularly when and where flexibility is needed.

Its attractiveness should still be assessed relative to other measures, however, such as demand response, power plant retrofits, smart-grid measures that enhance electricity networks, and other options that raise overall flexibility. Direct support for storage through mandates and policies remains the most common option to incentivise deployment, but greater emphasis should be placed on making regulations transparent and open, and on developing markets for capacity, flexibility and ancillary services so that storage can compete with other technologies and measures.

While electricity storage can in theory be paired with any energy service, electrification in the transport sector relies particularly heavily on continued innovation in battery technology. While electric vehicles on the road today account for a mere 1% of total vehicles (and just below 3% of annual sales), under the Sustainable Development Scenario (SDS)[38], charging batteries in electric vehicles will become the largest single source of electricity demand, accounting for around 5% of global demand by 2050.

To support the large-scale electrification of transport under the SDS, the volume of batteries needed for passenger and commercial light-duty vehicles increases 100-fold between now and 2040, while the volume for trucks, buses and other heavy-duty vehicles increases 14-fold. In order to reach this level of adoption, continued progress is needed to reduce costs and improve the performance of batteries at both cell and pack level.

The unit cost of batteries for electric vehicles has already dropped by 85% since 2010, with industry surveys recording a sales-weighted average cost of $156/kWh as of 2019. As costs fall and performance increases, the average battery pack size across electric vehicle type will also increase as a means for manufacturers to extend range and improve vehicle performance. These are key steps under the SDS, which sees a shift towards larger battery capacities to support longer ranges. The average battery pack for light passenger and commercial vehicles now carries 20% more energy than in 2018, and battery electric cars in most countries are in the 50-70 kWh range. The SDS sees continued increases in battery sizes, culminating in an average pack size that is 30% larger. Meanwhile, the share of battery electric vehicles, which have larger batteries than plug-in hybrids, continues to rise under the SDS to

[38] According to the IEA's Sustainable Development Scenario, close to 10,000 GWh of batteries across the energy system and other forms of energy storage will be required annually by 2040, compared with around 200 GWh today

seven out of every ten electric vehicles sold in 2040, according to the IEA[39].

Li-ion variants are the mainstay of electromobility applications, and with continued innovation in blends, chemistries and designs they are likely to continue to dominate over the coming decade. The current Li-ion landscape is a mix of lithium nickel cobalt aluminium oxide (NCA), lithium nickel manganese cobalt oxide (NMC) and lithium iron phosphate (LFP) cathodes for Li-ion batteries, with the most common chemistry and an emerging dominant design being NMC blends. Beyond unit cost reductions, the SDS is reliant on battery density continuing on an upward trajectory. Near-term developments already in the pipeline for current Li-ion technology are expected to reach cell-level energy densities of up to 325 Wh/kg and pack-level energy densities of 275 Wh/kg, both of which are close to the upper limits of current designs.

Beyond 2030, however, new technologies will be needed to follow the cost and performance trajectories set out under the SDS. These technologies are also key to facilitating the electrification of transport modes beyond cars. Despite ambitious electrification plans in the SDS, however, modes of transport other than cars account for just 11% of overall battery demand in 2030, highlighting the pivotal role of electric cars in the battery market over the next decade.

Candidates with the potential to meet the high-performance battery technology requirements include lithium-metal solid-state, lithium-sulphur, sodium-ion and even lithium-air batteries, which could represent an improvement compared with Li-ion in terms of cost, density and lifecycle, as well as further benefits owing to the more widely available materials found in these types of battery than those used in Li-ion technologies. At present, there is no single technology or dominant design that can outperform current Li-ion technology in all these areas.

Once their performance has been tried and tested in the research phase, the SDS requires these new technologies to be rapidly deployed and scaled up. The pace of development will need to be faster than that experienced by Li-ion; at the same time, these new technologies will be competing with established high-performing battery technologies, a challenge that Li-ion did not face to the same extent. Established Li-ion technology will in the meantime continue to benefit from cumulative experience gained from its large-scale manufacture and a solid understanding of its long-term durability characteristics in an expanding array of real-world applications.

Demand for the materials used in electric vehicle batteries, in particular the availability and management of cobalt and lithium resources – has also become a central concern. These will depend on changing battery chemistries. For instance, the energy density of cells with NMC cathodes rises as nickel content increases, and the current chemistry trajectory, in the light of the transition to electromobility, will naturally shift towards higher nickel and lower cobalt blends, another area in which there is continued pressure to innovate. To meet battery needs under the SDS, global cobalt demand would increase three-fold, and lithium four-fold, compared with current levels. Re-purposing and re-using batteries for second-life use in a new application and developing advanced recycling strategies could therefore greatly alleviate concerns over material availability and further reduce costs in applications such as grid-scale storage and energy access provision, neither of which require the levels of performance needed for electromobility.

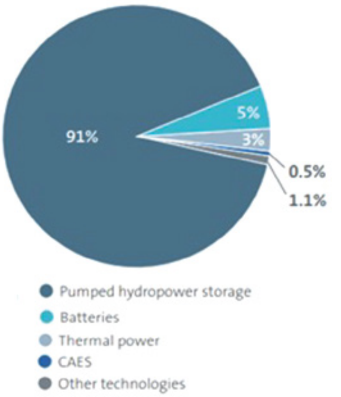
(b) Batteries and electricity storage in stationary applications

The use of batteries and other technologies in energy storage applications is also rapidly expanding, albeit at a slower rate than in the field of electromobility. Globally, total storage capacity stands at just under 200 GWh – the energy volume equivalent of storing the world's

[39] IEA (2020), "Innovation in batteries and electricity storage", https://iea.blob.core.windows.net/assets/77b25f20-397e-4c2f-8538-741734f6c5c3/battery_study_en.pdf.

electricity requirements for just six seconds. Most of this storage capacity is attributable to a single technology known as pumped storage hydropower (PSH), which accounts for over 90% of the world's storage volume, while batteries account for less than 3% (see Figure 13.20).

Figure 13.20 **Installed Capacity from Energy Storage Technologies, 2019**



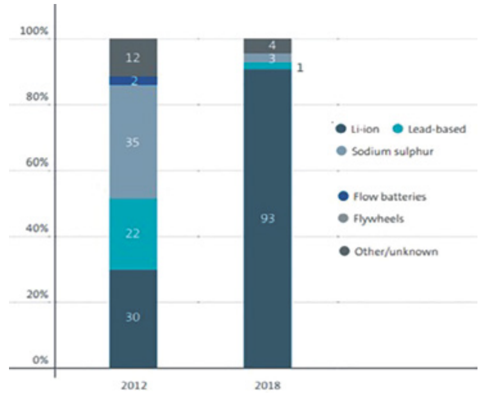
Source: IEA

An additional 10 GWh of pumped hydropower projects are currently in the pipeline, and a number of demonstrations of large mechanical and heat storage are planned. However, there are constraints to further scaling large-scale storage from technologies like PSH or compressed-air energy storage (CAES) given the limited number of suitable sites and their nature as capital-intensive projects involving large civil engineering works with long lead times.

In contrast, the use of batteries in stationary energy storage applications is growing exponentially: they are already being installed at an annual rate that is on a par with all other storage technologies combined.

Of all the available batteries, Li-ion has quickly become the dominant design, aided by spillovers from consumer electronics and electromobility applications. Excluding PSH, variants of Li-ion technology now account for more than 90% of new energy storage installations (see Figure 13.21). Other batteries make up the majority of the remaining 10%, with short-term technologies like flywheels and super-capacitors finding niche markets below 2%.

Figure 13.21 **Energy Storage Technology Mix, Excluding Pumped Hydropower Storage, 2012-2018**



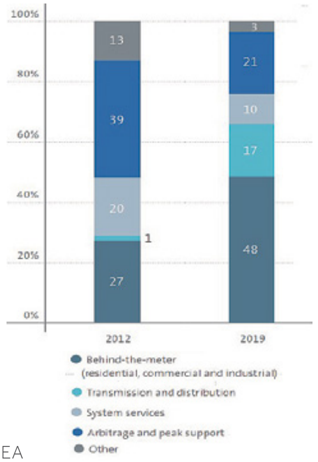
Source: IEA

The SDS sees a step change in the need for flexibility – power systems need to be able to maintain the required balance of electricity supply and demand in the face of uncertainty and variability in both supply and demand. As time goes on, many countries will experience a need to source more flexibility. By 2040, for instance, European Union countries on average will require enough flexibility to accommodate a share of wind and solar power equivalent to that of the global leader among major economies, Denmark.

Under the SDS, battery storage becomes a key provider of this flexibility, reaching a capacity of 550 GW by 2040, up from 6 GW in 2019. This increase in capacity is related to the rise of variable renewable energy capacity: today, the vast majority of utility-scale battery installations are paired with solar PV and wind power. More crucially, however, batteries are supported by market design that rewards an expanding range of services that batteries can provide. In 2012, the vast majority of storage was used for a small number of services (see Figure 13.22), mainly energy arbitrage on the grid or in the residential and commercial sector (shifting energy demand or supply in bulk from high- or low-demand periods).

13

Figure 13.22 **Applications of Energy Storage Technologies, 2012-2019**



Source: IEA

As markets, products and services have diversified – owing largely to the rise of variable renewables – the range of services has increased. Under the SDS, this range increases even further to cater for the growing need for new flexibility products, such as frequency and voltage regulation, inertial response and grid deferral, which are expanding to more markets. In turn, this drives technology innovation, as the power, energy, storage duration and lifecycle required by each of these services vary substantially.

This versatility of services and revenue streams, combined with the modularity of batteries, short lead times, wide range of applicability, economies of scale and overall technological progress, underpins the explosive growth in the battery market under the SDS. Other storage technologies, however, are also required for the energy transition. For instance, despite a growing shortage of suitable sites in some regions, the installed capacity of PSH increases by two-thirds by 2040, driven by more innovative designs that open up new locations and build on existing reservoir hydropower projects. Nevertheless, the very rapid growth in battery storage means that batteries overtake total PSH capacity by 2040.

To support this growth in battery storage, innovation in batteries alone is not enough. Battery systems are supported by a range of technologies, which currently account for over half of the total battery system costs. These include "balance-of-system" components such as housing, ventilation, monitors and controls, energy management systems as well as safety equipment such as thermal management and fire suppression, a power conversion system (a bidirectional inverter for battery charging and discharging), and other power equipment such as transformers and switchgear. In order to reach the goals set out under the SDS, the cost of these relatively mature technologies would need to drop to less than half the current levels by 2040.

K. Nuclear technologies

Nuclear power has historically been one of the largest contributors of carbon-free electricity globally and it has significant potential to contribute to power sector decarbonisation. Countries envisaging a future role for nuclear account for the bulk of global energy demand and CO_2 emissions. Nonetheless, in many jurisdictions nuclear power has trouble competing against other, more economic alternatives, such as natural gas or modern renewables. Concerns over safety and broader public acceptance remain obstacles to development.

With nuclear power facing an uncertain future in many countries, the world risks a steep decline in its use in advanced economies that could result in billions of tonnes of additional carbon emissions. Nuclear power plants contribute to electricity security in multiple ways. Nuclear plants help to keep power grids stable and can be a good complement in decarbonisation strategies since, to a certain extent, they can adjust their operations to follow demand and supply shifts. As the share of variable renewables like wind and solar photovoltaics rises, the need for such services will increase.

Small modular reactors (SMRs) continue to attract interest in both established nuclear countries, such as Canada and the United States, and in newcomer countries in Europe, the Middle East, Africa and Southeast Asia.

Research, development and demonstration (RD&D) and investment in SMRs and other advanced reactors are being encouraged through public-private partnerships.

In the United States, congress passed a bill on nuclear innovation that encourages public-private partnerships to test and demonstrate advanced reactor concepts, and to enhance public research laboratories' simulation and experimental capabilities. In February 2019, the US DOE announced plans to build a Versatile Test Reactor, or VTR. This new research reactor will help accelerate the testing of advanced nuclear fuels and materials required to develop Gen-IV reactor systems, according to the IEA[40].

Design certification of SMRs by nuclear safety authorities is progressing. Plans to construct the first modules of a new plant in Idaho have advanced with the manufacturers having been chosen and further support confirmed by the US DOE. In March 2020, Oklo submitted the first combined licence application for an advanced reactor technology to the NRC. Oklo is developing a 1.5 MW micro-reactor to supply energy at remote sites.

The Canadian government released its SMR roadmap in December 2018 and encouraged SMR vendors to take advantage of the opportunities offered to build and demonstrate their technologies. The CNSC (Canada's federal regulator) is currently reviewing ten SMR designs and received an application to build a micro modular reactor in 2019. In August 2019, the CNSC and the US NRC signed a memorandum of co operation to collaboratively develop the infrastructure needed to share and evaluate advanced reactor and SMR designs. In September 2019, a French consortium (the CEA, EDF, Technicatome and Naval Group) announced the development of a 170 MWe light-water reactor SMR design at the IAEA General Conference. The 340 MWe plant (two units per plant) is designed to replace mid-range fossil fuel-fired power plants in countries with small or poorly interconnected grids. In November 2020, Rolls-Royce and Exelon Generation signed a Memorandum of Understanding to pursue the potential for Exelon Generation to operate compact nuclear power stations both in the UK and internationally[41]. Exelon Generation will be using their operational experience to assist Rolls Royce in the development and deployment of the UKSMR. Rolls-Royce is leading a consortium that is designing an SMR. Its standardised, factory-made components and advanced manufacturing processes push costs down, while the rapid assembly of the modules and components inside a weatherproof canopy on the power station site itself avoid costly schedule disruptions.

The consortium is working with its partners and UK Government to secure a commitment for a fleet of factory built nuclear power stations, each providing 440MW of electricity, to be operational within a decade, helping the UK meet its net zero obligations. A fleet deployment in the UK will lead to the creation of new factories that will make the components and modules which will help the economy recover from the Covid-19 pandemic and pave the way for significant export opportunities as well. In addition, Russia connected its floating nuclear power plant Akademik Lomonosov to the grid in late 2019, and several countries such as Argentina, China, France and Korea are also developing SMR technologies.

Newcomer countries, such as Poland, Indonesia and Jordan, continue to design feasibility studies for the development of high-temperature reactors, the latter two in co operation with China. Saudi Arabia is also carrying out studies on nuclear desalination using SMRs. In SE Europe, there are five countries (i.e. Bulgaria, Hungary, Romania, Slovenia and Croatia) that currently operate nuclear power plants, while Turkey is expected to build no less than 3 nuclear power plants over the next decade, according to the World Nuclear Association[42].

[40] https://www.iea.org/reports/nuclear-power
[41] https://www.rolls-royce.com/media/press-releases/2020/08-11-2020-rr-signs-mou-with-exelon-for-compact-nuclear-power-stations.aspx
[42] https://world-nuclear.org/information-library/country-profiles.aspx

This means that nuclear energy has an important role to play in the SE European energy and electricity mix over the next decades. Table 13.13 shows the type of nuclear reactors as well as the capacities.

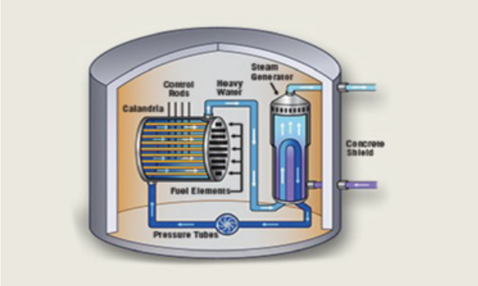
A pressurized heavy-water reactor (PHWR) is a heavy water cooled and moderated pressurized water reactor type, which instead of using a single large reactor vessel as in a pressurized water reactor (PWR), the nuclear core is contained in hundreds of pressure tubes (see Figure 13.23). PHWRs generally use natural uranium (0.7% U-235) oxide as fuel, hence needs a more efficient moderator, in this case heavy water (D2O). The reactor core is in a large tank called a calandria. There is a heavy water as the moderator in this tank. The calandria is penetrated by several hundred horizontal pressure tubes. These tubes form channels for the fuel. The fuel is cooled by a flow of heavy water under high pressure in the primary cooling circuit, reaching 290°C. The moderator in the tank and the coolant in the channels are separated. The hot coolant that leaves the channels goes to a steam generator, which in turn heats a secondary loop of water to steam that can run turbines and generator (as in the PWR).

Table 13.13 **Operational Nuclear Power Plants in SE Europe**

Country	Name	Type of reactor	Capacity (MWe)	Operation since
Bulgaria	Kozloduy 5	PWR	1003	1987
	Kozloduy 6	PWR	1003	1991
Hungary	Paks 1	PWR	479	1982
	Paks 2	PWR	477	1984
	Paks 3	PWR	473	1986
	Paks 4	PWR	473	1987
Romania	Cernavoda 1	PHWR	650	1996
	Cernavoda 2	PHWR	650	2007
Slovenia/ Croatia	Krsko	PWR	688	1981

Note: Cernavoda NPP in Romania has the only PHWR CANDU reactors operating in Europe.
Source: World Nuclear Association

Figure 13.23 **The PHWR Design**



Source: Cameco [43]

In Turkey, three separate projects are being or have been developed over the past decades with three different reactor designs and three different financing schemes. Despite this, in early 2018, construction formally only began on the first of these projects.

Table 13.14 **Nuclear Power Plants (Under Construction, Planned and Proposed) in Turkey**

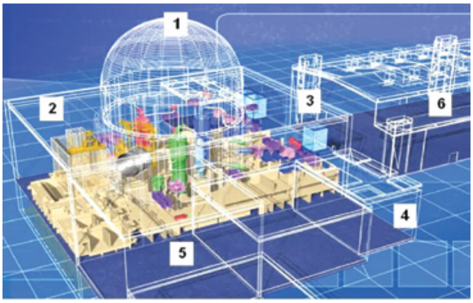
Name	Type of reactor	Capacity (MWe)	Start construction	Operation since
Akkuyu 1	VVER	1200	April 2018	2023
Akkuyu 2	VVER	1200	April 2020	2024
Akkuyu 3	VVER	1200	March 2021	2025
Akkuyu 4	VVER	1200	(2022)	2026
Sinop 1	ATMEA1	1150	uncertain	
Sinop 2	ATMEA1	1150	uncertain	
Sinop 3	ATMEA1	1150	uncertain	
Sinop 4	ATMEA1	1150	uncertain	
Igneada 1-4	AP1000x	2x1250		
	CAP1400x2	2x1400		

Source: World Nuclear Association

Turkey is expected to be the first country to use the ATMEA1 pressurized water reactor (see Figure 13.24), designed by Areva and Mitsubishi Heavy Industries (MHI). ATMEA1 is a Generation III+ model. Thus, it has properties similar to those of the EPR reactor in terms of safety and environmental impact. It offers great operational flexibility and a high degree of competitiveness because of its reduced electricity production costs. It also offers great operational flexibility.

[42] https://world-nuclear.org/information-library/country-profiles.aspx
[43] https://www.cameco.com/uranium_101/electricity-generation/types-of-reactors/

Figure 13.24 **The ATMEA1 Pressurized Water Reactor Design**



1. Reactor Building
2. Fuel Building
3. Safeguard Building
4. Emergency Power Source Building
5. Nuclear Auxiliary Building
6. Turbine Building

Source: ATMEA[44]

13.4 The Role of Innovation

It is generally agreed that quicker progress towards energy transition and the achievement of a net-zero environment will depend on faster innovation in electrification, hydrogen, bioenergy and CCUS. Just over one-third of the cumulative emissions reductions in the years ahead, say by 2040, stem from technologies that are not commercially available today. In its Faster Innovation case, the IEA[45] estimates that increased electrification will come 25% from CCUS, around 20% from bioenergy, and around 5% from hydrogen.

Long-distance transport and heavy industry are some of the hardest emissions to reduce. Energy efficiency, material efficiency and avoided transportation demand (e.g. substituting personal car travel with walking or cycling or use of mass transit systems), all play an important role in reducing emissions in long-distance transport and heavy industries. But nearly 60% of cumulative emissions reductions for these sectors in the Sustainable Development Scenario come from technologies that are only at demonstration and prototype stages today. Hydrogen and CCUS account for around half of cumulative emissions reductions in the steel, cement and chemicals sectors. In the trucking, shipping and aviation sectors, the use of alternative fuels – hydrogen, synthetic fuels and biofuels – ranges between 55% and 80%. Highly competitive global markets, the long lifetime of existing assets, and rapidly increasing demand in certain areas further complicate efforts to reduce emissions in these challenging sectors. Fortunately, notes the IEA, the engineering skills and knowledge these sectors possess today are an excellent starting point for commercializing the technologies required for tackling these challenges.

Most analysts agree that energy efficiency and renewables are fundamental for achieving climate goals, but there are large portions of emissions that will require the use of other technologies. A large part of these emissions come from sectors where the technology options for reducing them are limited – such as shipping, trucks, aviation and heavy industries like steel, cement and chemicals. Decarbonising these sectors will largely demand the development of new technologies not yet in use. And many of the clean energy technologies available today need more work to bring down costs and accelerate deployment.
Innovation emerges as top primarily in fostering new technologies and advancing existing ones. In this report and as already pointed out by the IEA (8) we should make the following distinctions.

(a) Innovation is not the same as invention. After a new idea makes its way from the drawing board to the laboratory and out into the world, there are four key stages in the clean energy innovation pipeline. But this pathway to maturity can be long, and success is not guaranteed:
(b) Prototype: A concept is developed into a design, and then into a prototype for a new device (e.g. a furnace that produces steel with pure hydrogen instead of coal).
(c) Demonstration: The first examples of a new technology are introduced at the size of a full-scale commercial unit (e.g. a

[44] https://inis.iaea.org/collection/NCLCollectionStore/_Public/47/078/47078911.pdf
[45] IEA (2020), "Energy Technology Perspectives 2020 - Special Report on Clean Energy Innovation", https://iea.blob.core.windows.net/assets/04dc5d08-4e45-447d-a0c1-d76b5ac43987/Energy_Technology_Perspectives_2020_-_Special_Report_on_Clean_Energy_Innovation.pdf

system that captures CO_2 emissions from cement plants).

(d) Early adoption: At this stage, there is still a cost and performance gap with established technologies, which policy attention must address (e.g. electric and hydrogen-powered cars).

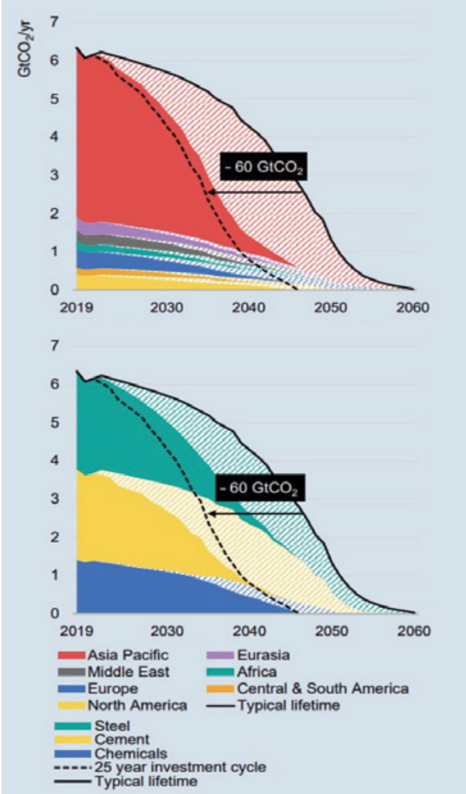
(e) Mature: As deployment progresses, the product moves into the mainstream as a common choice for new purchases (e.g. hydropower turbines).

A general observation regarding technology choices is that there are no single or simple solutions to putting the world on a sustainable path to net-zero emissions. Reducing global CO_2 emissions will require a broad range of different technologies applied in parallel and across all sectors of the economy in various combinations and applications. These technologies are currently at varying stages of development, but we can already map out how much they are likely to contribute to the emissions reductions necessary to meet international energy and climate goals.

The good news is that the key technologies that the energy sector needs in order to lower effectively emissions are known today, but the drawback is that not all of them are ready as yet or commercially available. Around half of the cumulative emissions reductions that would move the world onto a sustainable trajectory come from four main technology approaches. These are, (a) the electrification of end-use sectors such as heating and transport, (b) the application of carbon capture, utilization and storage (CCUS), (c) the use of low-carbon hydrogen and hydrogen-derived fuels and (d) the use of bioenergy. However, each of these areas faces challenges in making all parts of its value chain commercially viable in the sectors where reducing emissions is hardest. IEA's new ETP Clean Energy Technology Guide[46] provides a framework for comparing the readiness for the market of more than 400 component technologies.

As underlined by the IEA early-stage technologies play an outsized role, as around 35% of the cumulative CO_2 emissions reductions needed to shift to a sustainable path come from technologies currently at the prototype or demonstration phase. A further 40% of the reductions rely on technologies not yet commercially deployed on a mass-market scale and this calls for urgent efforts to accelerate innovation. The fastest energy-related examples in recent decades include consumer products like LEDs and lithium ion batteries, which took 10-30 years to go from the first prototype to the mass market. As the IEA argues, these examples must be the benchmarks for building the array of energy technologies to get to net-zero emissions.

Figure 13.25 **Unlocking CO_2 at the Next Investment Cycle in Key Industrial Sectors**



Source: IEA

[46] A new interactive tool developed by the IEA that provides detailed information and analysis on the level of maturity of over 400 different technology designs and components, as well as a compilation of cost and performance improvement targets and leading players in the field. Available online at www.iea.org/articles/etp-clean-energytechnology-guide.

IEA's proposals for enhancing clean fuel innovation in the energy transition phase is of particular relevance to SE European countries and this is why we quote them verbatim. "For governments aiming to achieve net-zero emissions goals while maintaining energy security, these principles primarily address national policy challenges in the context of global needs, but are relevant to all policy makers and strategists concerned with energy technologies and transitions:

1. Prioritise, track and adjust. Review the processes for selecting technology portfolios for public support to ensure that they are rigorous, collective, flexible and aligned with local advantages.
2. Raise public R&D and market-led private innovation. Use a range of tools – from public research and development to market incentives – to expand funding according to the different technologies.
3. Address all links in the value chain. Look at the bigger picture to ensure that all components of key value chains are advancing evenly towards the next market application and exploiting spillovers.
4. Build enabling infrastructure. Mobilise private finance to help bridge the "valley of death" by sharing the investment risks of network enhancements and commercial-scale demonstrators.
5. Work globally for regional success. Co-operate to share best practices, experiences and resources to tackle urgent and global technology challenges, including via existing multilateral platforms".

13.5 Promoting Clean Energy Innovation

The critical role of innovation in order to meet long-term energy and climate targets is increasingly being emphasized in global and regional policy discussions. There appears to be little disagreement on the corollary that the world needs faster scale-up of low-carbon technologies for clean energy transition. However, according to that dictum many technologies are not yet ready for all the markets where they will be needed. They require performance and cost improvements, even though the last few decades have seen unprecedented efforts to accelerate clean energy development, such as in the use of renewable sources of energy or low-carbon mobility. Many of these technologies will need adapting to local needs and specificities, particularly in emerging economies, which are expected to account for much of future energy demand growth.

Latest IEA findings suggest that most energy technologies are not on track to provide the clean energy transitions targeted by governments. Deployment challenges for mature technologies hinder mass-scale market uptake in many instances. There appear to be a general consensus that achieving global energy and climate policy goals will require more, better and cheaper technologies.

Governments are of course central to the success of clean energy innovation, and global policy support needs strengthening. The role of private-sector actors is critical to bringing emerging technologies to market, but governments play an outsized role in funding and supporting early-stage, high-risk research and development (R&D). As lead investors in novel and risky projects and sometimes in start-ups, the "entrepreneurial" role of governments is most evident in the earlier stages of development for which uncertainty and market values discourage corporates.

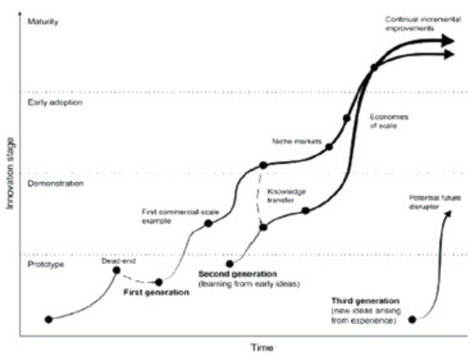
Dedicated policy is generally accepted as necessary for clean energy innovation, as it is for areas of medical research, due to its long-term "public good" objectives that are often undervalued by private markets. Countries with high rates of success tend to act across the whole system, promoting innovation through funding, institutions, industry collaboration, markets and intellectual property (IP) protection, among others.

What is energy technology innovation?

In discussing innovation in the energy sector, it is important to understand how energy technologies are invented, turned into products and modified throughout their lives. Technology innovation is defined as "the process of generating ideas for new products or production processes and guiding their development all the way from the lab to their mainstream diffusion into the market". Equipment and processes that change how or how much energy is consumed are included (e.g. in power, buildings, industry, transport).

There are four main stages of development for emerging technologies: prototype, demonstration, early adoption and maturity. Each requires different policy support programmes and stakeholders. The ETP Clean Energy Technology Guide tracks progress of innovation of over 400 energy technologies, and maps their stage of development and ongoing activities and demonstration.

Figure 13.26 **Four Stages of Technology Innovation and the Feedbacks and Spillovers that Improve Successive Generations of Designs**



Source: IEA

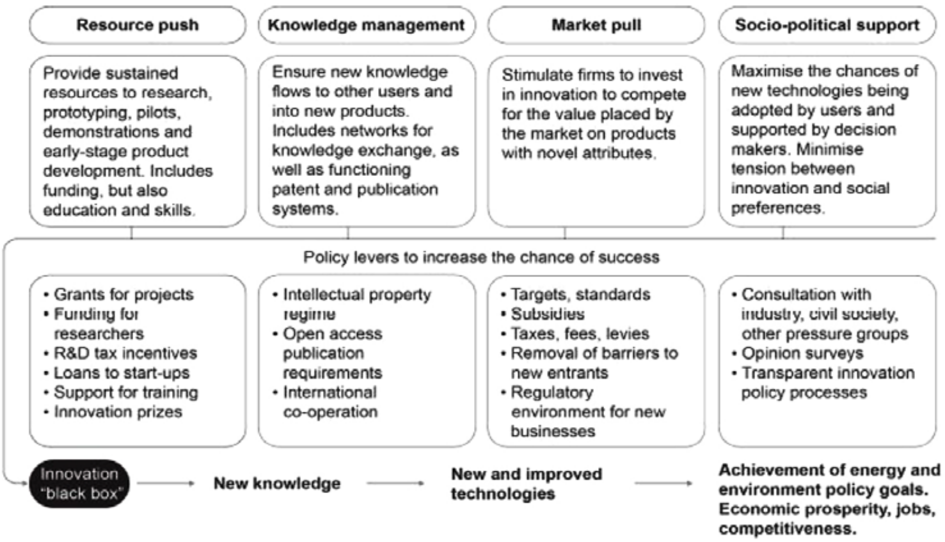
In this context, it is important to consider the four (4) pillar approach to energy innovation framework as exemplified by the IEA. According to its methodology, successful energy innovation systems are structured around four core functions as follows:

1. Resource push. The energy innovation system requires a sustained flow of R&D funding, a skilled workforce, research infrastructure and clear priorities to guide the search of innovation activities.
2. Knowledge management. The energy innovation system needs incentives and IP systems for inventors and must enable knowledge exchange among stakeholders.
3. Market pull. The energy innovation system needs to make R&D risks worthwhile, which may depend on market rules and incentives.
4. Socio-political support. The support of a broad range of actors may be required to enable new ideas to emerge and reach markets.

Targeting innovation as part of an overall energy policy is a complex process and needs serious financial resources, capable administration, cooperation between academia and industry and teams of dedicated scientists, engineers and technology promoters. Unless such prerequisites are satisfied inspired thoughts, clean technology visions and over ambitious targets remain unfulfilled. Hence, energy planners must be aware that the innovation journey is complex, lengthy, uncertain, and often ends in failure. Each stage comes with new risks, the selection environment is dynamic and a broad range of actors need to be aligned.

We should also stress that emerging technologies are modified as feedback loops and experiences from other sectors or countries help shape new R&D activities, as investor or consumer preferences shift, as competing technologies improve. In addition to endogenous mechanisms, exogenous factors shape the innovation journey and chance of success, such as past policy choices, macroeconomic developments, incumbent power and infrastructure, as well as history, culture and social norms. It is an accepted fact in the innovation niche area that new ideas for energy technologies usually attract billions of dollars of funding despite the risk and complexity.

Figure 13.27 **Four Pillars of Effective Energy Innovation Systems**



Source: IEA

Therefore, it is important to consider all the factors that influence innovation in order to understand why some technologies attract more funding or are more successful than others.

The case of SE Europe

Although no major energy technology innovation as such has originated in this part of the world in recent years, there have been major inroads when it comes to the large-scale application of alternative energy systems. In this context, we have witnessed several successful attempts in modifying existing technologies to serve local needs, especially when it comes to mass local manufacturing. Hence, a fair amount of innovation has come about by adapting existing technologies, especially in RES, to enable them to maximise performance under local geomorphological, economic and climate conditions.

The following is an indicative list of successful energy technologies, which have been adapted, further developed and applied at local level in different SEE countries:

• Solar Water Heaters (SWH)

Originally developed in USA in the early part of the 20th century, they were successfully introduced in Israel in the mid-1950's and hence developed through mass manufacturing in Israel, Cyprus, Greece and Turkey. Thanks to high quality and high efficiency (improved over the years), the region is a net exporter of SWH to the rest of Europe but lost globally.

• Solar Photovoltaics

Although the majority of cells in the form of panels are imported, there are some successful examples of local manufacturing especially in Israel, Greece and Turkey, where a limited degree of innovation has been introduced in the manufacturing and assembly process. Moreover, a certain amount of innovation has been introduced in flexible metal support structures, which are necessary in installing PV panels in sloppy arid areas so as to take maximum advantage of available land.

• High Enthalpy Geothermal Applications for Power Generation

With the exception of Turkey and earlier failed attempts by Greece, there is no much interest in the development of this much promising renewable energy source. Turkey is undoubtedly the leader in SEE in utilising high enthalpy geothermal energy for power generation (see Chapter 11).

In developing geothermal energy to the scale used today (with more than 1.5 GW of installed geothermal capacity in operation), Turkish engineering firms had to innovate in a number of areas, especially in the reuse and management of geothermal fluids so as to avoid land contamination. The introduction and testing of new types of materials and techniques for drilling, heat exchangers and steam generation was at the core of innovative efforts.

• Low Enthalpy Geothermal for Applications for Buildings

As there is growing interest in several countries in the region to utilise low temperature geothermal applications, especially for the heating and cooling of buildings and through the use of heat pumps, several innovations are taking place at local level in conjunction with improved construction techniques. This is a very promising area for low-tech innovation with immediate benefits for the improvement of energy efficiency.

• Biofuels

There are several biofuel production plants operating in several countries in the SEE region. Their operation depends on the input from high yield plants and the ability of refineries to absorb their ethanol production. There is considerable margin for innovation both at technical level, through the improvement of the production process in the biofuel facilities, but also in the selection, cultivating and use of energy intense plants.

• Wind Energy

Although no academic research or commercial enterprise over the last few years in SEE has resulted in any astounding innovations in new wind turbine concepts or the development of new materials, considerable innovation has come about in the siting and installation of wind turbines as they had to face unique geomorphological conditions in several countries in the region (in mostly mountainous and remote windswept areas) which necessitated the development of novel design principles for wind farms and the introduction of remote management techniques at a very early stage. Cumulative wind farm management experience in the region has resulted in the introduction of several innovative elements in design, siting and installation.

These have helped speed up construction and commissioning while they have smoothed out teething problems and helped maximise performance. In this context work undertaken by a number of Greek, Romanian and Turkish companies stands out as it has provided inspiration and examples concerning the introduction of new techniques during the design phase but also during performance, through the application of specially adapted automation methods for both monitoring and operation of wind farms. The real technological-innovation challenge for the SEE region, when it comes to wind energy, is no doubt the offshore wind sector as it provides many challenges for innovative design and construction of support systems.

• Small Hydroelectric Plants

Closely linked with the geography and geomorphology of the region, the large-scale development and application of small hydro plants (say up to 15 MW) does present serious design, construction and operational challenges. In this context, a number of innovations have emerged over the years mostly related to the design and construction of catchment areas, the guided direction of water flows and extension of the plant's operational period. Albania, Serbia, Greece and Turkey appear to have accumulated considerable experience in this area.

• CCUS

Although carbon capturing and use technologies are not yet applied in the region, there is work going on in a number of countries which to a large extent rely for power generation on indigenous coal and lignite deposits. In view of the particular characteristics of the mostly open cast mines to be found in the region and the considerable local expertise, which has developed over the years in mine development, infrastructure and management, the introduction of CCUS technologies does not present insurmountable difficulties.

On the contrary, there is ample engineering expertise which could be used to adapt and apply CCUS methods which will enable the prolongation in the use of a relatively cheap local fuel source, while minimising and zeroing CO_2 emissions. So far, only Serbia appears to have taken this challenge seriously and according to reports there is already a pilot project in operation developed by NIS, while Turkey, Bulgaria and Greece are carrying out detailed surveys. Yet, CCUS could emerge as a promising area where locally developed innovative techniques could emerge and widely applied providing much needed relief from rising emissions.

13.6 Cybersecurity and Energy System Resilience

Electricity is an integral part of all modern economies, supporting a wide range of critical services, including health care, the internet and transportation. The secure of uninterruptible supply of electricity is thus of paramount importance. Digitalisation is rapidly transforming the electricity system, bringing many benefits for businesses and consumers. At the same time, increased connectivity and automation could raise risks to cybersecurity and the threat of cyberattacks. A successful cyberattack could trigger the loss of control over devices and processes in energy systems, in turn causing physical damage and widespread service disruption. Recent estimates show that overall energy Information Technology (IT) and cybersecurity software and services spending globally is expected to rise from \$19 billion in 2020 to \$32 billion in 2028 . Only about 7% of this is security-related, representing around \$1.3 billion in 2020, though this component is proportionally growing faster[49].

The Case of SE Europe

A 2019 Energy Community study[50] concluded that its Contracting Parties have different levels of risks, which are mostly induced by geopolitical situation. In the first group of countries, there are the Western Balkans' Energy Community Contracting Parties (i.e. Albania, Bosnia and Herzegovina, Kosovo, Serbia, Montenegro and North Macedonia) that all have by EU standards smaller sized energy markets and are coping with similar, if not the same, cybersecurity issues (risks, incidents). In this group by cybersecurity maturity level the two most advanced countries (i.e. Serbia and Montenegro) may contribute considerably to the regional overall cybersecurity level by cooperating actively with their neighbours.

That would lower the risk of the whole group. If regional cooperation is somehow more deepened with cooperating energy computer security incident response teams (CSIRTs) and joint exercises and early warning system, Energy Community believes that this will put risks at more acceptable levels. The second group with higher risk levels members are Georgia and Moldova, which are practically under constant risk of cyber-war type of incidents. Those two countries need more investment in high tech cyberdefence and must engage very skilled professionals to accomplish some kind of progress in managing cyber risks, not to forget active cooperation on cyber issues with friendly neighbours and NATO's

48 Business Wire (2020), "Navigant Research Report Finds Global Annual Market for Energy IT and Cybersecurity for Software and Services Is Expected to Reach \$32 Billion by 2028", https://www.businesswire.com/news/home/20200211005108/en/Navigant-Research-Report-Finds-Global-Annual-Market

49 Walton, R. (2020), "Utilities say they are prepared to meet cyber threats. Are they?", https://www.utilitydive.com/news/utilities-say-they-are-prepared-to-meet-cyber-threats-are-they/572080/

50 Energy Community (2019), "Final Report of a study on cybersecurity in the energy sector of the Energy Community", https://www.euneighbours.eu/sites/default/files/publications/2020-02/Blueprint_cyber_122019.pdf

cyber capability defence facilities. In the third group is Ukraine, which is a risk assessment story for itself as being in state of hybrid war not only in cyberspace but also for real. The Ukrainian energy market is huge amongst other Energy Community Contracting Parties and of large strategic interest not only for EU but for USA and Russia as well. As Ukraine's cyber risks are of critical levels, the country is managing them fast and in their best knowledge. Nevertheless, all neighbouring countries must be aware of those risks during any kind of cooperation in the energy sector and must adjust their respective systems/ processes to be able to handle the same level of risks (this includes Energy Community also). Apart from the aforementioned SE European countries, there are also Greece and Turkey. More specifically, Greece's Energy Ministry was hit by a cyberattack in early July 2021 and as a result numerous files were "locked", while at the same time "sensitive" documents and data were retrieved[51]. Several energy companies, such as PPC, and public institutions in Greece have already taken necessary precautionary measures in order to mitigate, if not eradicate, any attempt of cyberattack.

For instance, Greece's IPTO announced on August 27, 2021 an electronic tender for the nomination of a contractor for the provision of services in order to enhance Cybersecurity Resilience of its infrastructure. The total budget amounts to €10.5 million, while the duration of the contract, including warranty and maintenance services, is 5.5 years[52].

Similarly, Turkey seems to be one of the first countries in SE Europe that have already experienced a cyberattack in their electricity grid. More specifically, sources from the country's Energy Ministry claimed in December 2016 that a major cyberattack was the source of the widespread electricity cuts across Istanbul, according to reports in Turkish media. "The attacks were generally aiming to seize Internet sites and secure infiltration," a senior anonymous source said on December 31, as quoted by state-run Anadolu Agency. "Many infiltration attempts to the systems controlling our transmission and electricity producing lines were determined and prevented.

The infiltration attempts are indicators of a major sabotage preparation against Turkey's national electricity network," he added [53].

Discussion

Digitalisation offers many benefits both for energy systems and clean energy transition. At the same time, the rapid growth of connected energy resources and devices is expanding the potential cyberattack surface, while increased connectivity and automation throughout the system are raising cybersecurity risks. The threat of cyberattacks on energy systems is substantial and growing.

Threat actors are becoming increasingly sophisticated at carrying out attacks. A successful cyberattack could trigger the loss of control over devices and processes, in turn causing physical damage and widespread service disruption. While the full prevention of cyberattacks is not possible, energy systems can become more cyber resilient – to withstand, adapt to and rapidly recover from incidents and attacks, while preserving the continuity of critical infrastructure operations. Policy makers, regulators, utilities and equipment providers have key roles to play in ensuring the cyber resilience of the entire energy value chain. Policy makers are central to enhancing the cyber resilience of energy systems, beginning with raising awareness and working with stakeholders to continuously identify, manage and communicate emerging vulnerabilities and risks.

51 Ecopress (2021), "Digital blackout from a cyberattack on Greece's Energy Ministry", (in Greek), https://ecopress.gr/psifiako-blakaout-apo-kyvernoepithesi-chaker-sto-ypen/

52 IPTO (2021), "Upgrade Cybersecurity Resilience of IPTO's Infrastructure", (in Greek), https://www.admie.gr/sites/default/files/promitheies/42115/42115-9-prokiriksi.pdf

53 Hurriyet Daily News (2016), "Major cyber-attack on Turkish Energy Ministry claimed", https://www.hurriyetdailynews.com/major-cyber-attack-on-turkish-energy-ministry-claimed-107981

Policy makers are also ideally placed to facilitate partnerships and sector-wide collaboration, develop information exchange programmes and support research initiatives across the energy sector and beyond. Ecosystem-wide collaboration can help to improve understanding of the risks that each stakeholder poses to the ecosystem and vice-versa.

As more and more cyberattacks are expected to take place in the energy sector in SE Europe, it is high time to set up an effective regional Energy Cyber Security Advisory Committee in order to assess and prevent them. This Committee could work closely with the Energy Community Secretariat, the International Energy Agency (IEA), ENTSOe, ENTSOg and the recently launched SELeNe CC in Thessaloniki. This will be an ad hoc group composed of specialists in different sectors e.g. electricity, energy efficiency and cogeneration, renewables, oil and gas, coal, nuclear and Information Technology.

The group will first of all undertake to ascertain cyberattacks in the regional energy sector and then proceed in cataloguing in detail the energy infrastructure involved and also assess the degree of its exposure. Then, the Committee will proceed to chart a strategy for the strengthening and upgrading of energy infrastructure in relation to the broader steps that need to be taken, such as precautionary safety measures.

The overall aim of this initiative will be to prepare a comprehensive report with detailed recommendations, including a roadmap and fully costed proposals for the work that is required in order to ring fence SE Europe's energy systems and protect them from extreme phenomena of cyberattacks.

References

(1) *Serbia Energy (2015), "SEE, Serbia, Bosnia, Montenegro, Macedonia, Albania, Croatia: Energy market integration and EU integration, mutual benefits and integration scenarios", http://serbia-energy.eu/see-serbia-bosnia-montenegro-macedonia-albania-croatia-energy-market-integration-and-eu-integration-mutual-benefits-and-integration-scenarios/*

(2) *ENTSO-E (2015), "Regional Investment Plan 2015 – Continental South East region", https://www.entsoe.eu/Documents/TYNDP%20documents/TYNDP%202016/rgips/Regional%20Investment%20Plan%202015%20-%20RG%20CSE%20-%20Final.pdf*

(3) *AT Kearney (2014), "Time to Develop an Energy Master Plan for Southeast Europe", https://www.atkearney.com/documents/10192/5284670/Time+to+Develop+an+Energy+Master+Plan+for+Southeast+Europe.pdf/2a1cab22-0ff7-4983-971c-08eaa0693f57*

(4) *EIHP (2013), "South East Europe Energy Community - Development of Electricity Infrastructure", https://www.eihp.hr/~dbajs/WA120.pdf*

(5) *IRENA (2013), "Priorities, Strategies and Issues for Developing Transmission Grids", https://www.irena.org/documentdownloads/events/2013/december/background_paper-c.pdf*

(6) *Europa (2016), "Technical information on Projects of Common Interest", https://ec.europa.eu/inea/sites/inea/files/technical_document_8_march_2016for_publication_-_change_22092016.pdf*

(7) *EIHP (2015), "South East European Distribution System Operators Benchmarking Study", http://www.eihp.hr/wp-content/uploads/2015/10/SEE-DSO-Benchmarking-Study-FINAL1.pdf, prepared for USEA*

(8) *Turkey's Energy Market Regulatory (2015), "Cross-border Trade – Turkish Electricity Import and Export Rules", http://pubs.naruc.org/pub/256E2667-974E-5EC1-D92D-82B42FF3116E*

13

14

Energy Demand and Supply Projections for SE Europe

Energy Demand and Supply Projections for SE Europe

14.1 Introduction

This chapter presents the projections of key energy and climate indicators for various South East Europe countries together with aggregations of countries with similar overarching policies (EU member states in SEE and Western Balkans countries-WB6). The most recently available studies and the official country submissions of strategic documents (such as the Integrated National Energy and Climate Plans) were used in order to collect and analyse these projections. The purpose is to present the evolution of the national energy systems corresponding to a "where we are heading" storyline, providing a simple but comprehensive picture of the energy and Greenhouse Gases (GHG) emissions dynamics under the "current policy" efforts until 2040. The quantitative information is also available in the form of a "dashboard", a visual tool which aims to support the transparent analysis, and the aggregation of the key figures.

The chapter is organized on two levels of detail. At the first level, country profiles with a short "highlight" section summarising the key country-specific insights from the projections and charts with their descriptive texts providing more detailed information of the evolutions of the identified absolute and relative indicators are presented. When available in the sources which were used, additional information such as technology-specific insights or alternative scenarios outcomes are briefly reported. Since this approach was based on existing studies, data related issues or adjustments are reported for each country. At a second level, an aggregation of the projections for countries with similar overarching policies is presented. Therefore, charts and tables aggregating the projections of the six EU member states (Bulgaria, Croatia, Cyprus, Greece, Romania, Slovenia) and of the six Western Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, North Macedonia and Serbia) are reported and discussed in order to provide regional overviews and additional elements of analysis.

Methodology

The analysis has been conducted by means of a review of the most recent published sources at country and regional level. Data have been extracted, converted and in some cases processed, and used to generate six main energy and climate indicators at country level:

- Net import by energy commodity.
- Gross Inland Consumption (GIC) by energy commodity.
- Electricity generation by type.
- Final Energy Consumption (FEC) by energy commodity.
- Final energy consumption by sector.
- GHG emissions (excluding LULUCF) with the GDP evolution.

Additional indicators and analyses can be derived from the combination of the above-mentioned basic information; for example, intensities can be calculated as ratios (e.g. FEC over GDP or GHG emissions over GIC). A consistency check of the data, based on the principles of the energy balance, has been carried out to validate and keep full consistency over the reported energy chains (energy imports - gross inland consumption – transformation sector - final energy consumption – related GHG emissions). In some cases, it was necessary to make a few inserts or adjustments to the original data to fill in some gaps. The details on these interventions are reported in the corresponding place in the following text for transparency. It should be noted that most of the available analyses do not include the effect of the COVID-19 pandemic and its possible long-term effects to the macroeconomic development and the energy systems of the countries in the region.

[1] The end of the horizon (2040) is chosen on the basis of the analysis of the relevant data sources, thus allowing a full harmonization / benchmarking across the SEE countries. It should be also noted that, unless explicitly reported in the official sources, values for 2015 are taken from the SE Europe Energy Outlook 2016/17.

14.2 Projections for a "Baseline" scenario

The projections for the development of the energy systems of SEE countries under a "Baseline", "Reference" or "With Existing Measures" scenario approach was considered appropriate in order to present the possible future pathways paved by current policies. The following sections present the projections of relevant scenarios which are available in published reports and studies for each country. As expected, different studies were based on different background assumptions. Therefore, GDP and population projections are presented per country, as the main drivers for the development of the energy systems, and further details on the main assumptions are included, when available. The fact that the analysis is based on the projections of individual countries, without using a regional energy model, could lead to some inconsistencies related to the trade of energy commodities, mainly electricity; however, it is expected that this effect would be minor.

14.2.1 Projections per country

Before aggregating the projections over groups of countries in the region, it is particularly interesting to investigate the details of the energy system of each one of the thirteen countries under consideration. The following table provides a qualitative overview of the key inputs and outputs of the assessment.

Country / Criterion	Completeness, accuracy and updating of quantitative information gathered from the official sources[2]	GHG emissions trend 2020-2040 (qualitative)
Albania (WB6)		↗
Bosnia and Herzegovina - BiH (WB6)		↗
Bulgaria (EU)		↘
Croatia (EU)		↘
Cyprus (EU)		↘
Greece (EU)		↘
Kosovo (WB6)		↗
Montenegro (WB6)		↘
North Macedonia (WB6)		↗
Romania (EU)		→
Serbia (WB6)		→
Slovenia (EU)		↘
Turkey (Peripheral)		↗

Key: weak strong

Albania

Highlights

- Energy consumption and GHG emissions continue to grow almost linearly.
- Import dependency on fossil fuels increases.
- Small reduction of carbon intensity by 2040.

[2] This is only meant to give the readers an indication of the degree to which collected data from the available sources needed to be post-processed/adjusted/integrated with assumptions in order to depict a complete dataset.

Key data sources

Baseline scenario, Albanian Strategy of Energy 2015-2030 (2015)

Third national Communication of the Republic of Albania on Climate Change (2016).

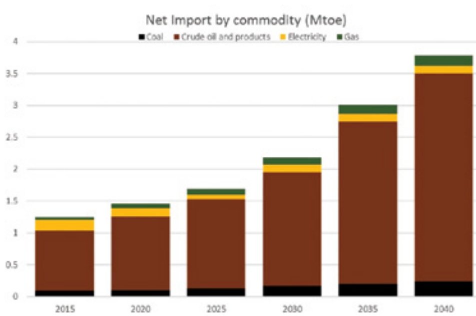
Author's elaboration for the projections between 2030 and 2040.

The projected evolution of the main exogenous factors influencing the energy system and GHG emissions developments of Albania are reported below.

Albania (WB6)	2015	2020	2025	2030	2035	2040
Population (million)	3.2	3.24	3.28	3.3	3.3	3.25
GDP (billion Euro)	9.8	12.3	14.5	17.0	19.8	23.0

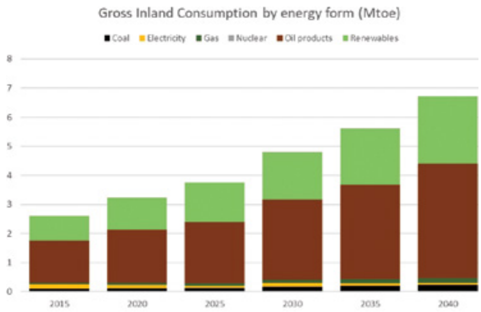
The net imports of fossil fuels in Albania increase following a trend similar to that of the Gross inland consumption, due to the limited amount of indigenous conventional energy sources. Net imports are dominated by oil products (around 80% of the total) and the share of imported gas increases reaching almost 5% of the total imports by 2040. Import dependency remains at a level above 45% until 2030 and increases to almost 55% by 2040.

Figure 14.1 **Albania: Net Imports**



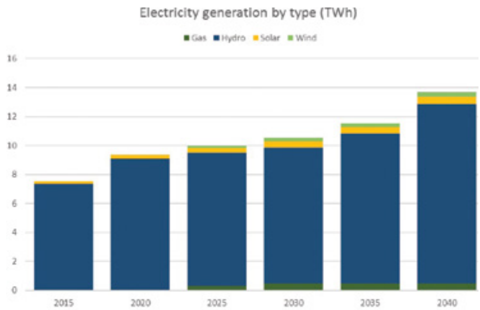
Gross Inland Consumption (GIC) in Albania is projected to grow by a factor of almost 2.5 between 2015 and 2040 (Figure 14.2). It is dominated by oil products which cover between 55% and 60% of the total, while renewable energy (mainly biomass and hydro power) covers around one third of the total, for the whole time horizon. Natural Gas is expected to enter the electricity generation sector by 2025 increasing its share in the GIC, but this share is still relatively small until 2040.

Figure 14.2 **Albania: Gross Inland Consumption**



Hydro power continues to be the main source of gross electricity generation in Albania reaching a level of 12TWh in 2040 and generating 90% of the total electricity (Figure 14.3). Natural gas is introduced in the power sector in 2025 and has a relatively limited contribution, while renewable energy (solar and wind) contributes 6% of the gross generation in 2040.

Figure 14.3 **Albania: Gross Electricity generation by source**

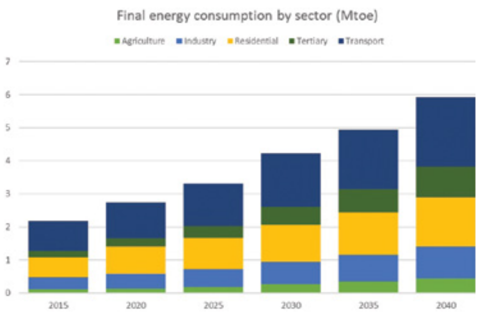


Following a similar trend to GIC, Final Energy Consumption (FEC)[3] increases considerably until 2040 reaching a level of 5.9Mtoe. Transport continues to dominate the final energy consumption (covering between 35% and 40% of the total) and is followed by the residential sector (which covers 25% to 30% of the total). There is a considerable increase of

[3] Since the available scenario projections reach only until 2030, the projection of FEC between 2030 and 2040 was performed using the GDP projection and assuming that the energy intensity follows the same trend. The relative contribution of each energy commodity and each sector is assumed not to change over the decade 2030-40. Using the energy balance principle, the projected FEC is then translated into GIC and the net imports are calculated assuming that the domestic energy production is limited to the same level as in the previous years.

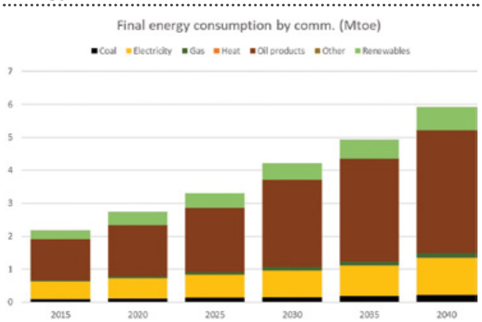
the services sector which constitutes 15% of the total FEC by 2040 (from 10% in 2020) while industry covers a share around 17% for all the years in the analysis.

Figure 14.4 **Albania: Final Energy Consumption by Sector**



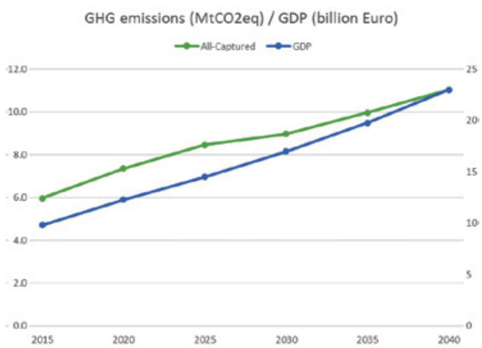
Final energy consumption is dominated by oil products which cover more than 60%, followed by electricity which covers close to 20% of the total demand. The share of renewables remains relatively constant (around 12%) and reaches a level of 0.7Mtoe by 2040. The consumption of natural gas increases to 0.15Mtoe by 2040 but still covers only a small part of the final energy consumption.

Figure 14.5 **Albania: Final Energy Consumption by energy form**



The total amount of renewable energy in the final energy consumption (calculated as the sum of renewable energy in FEC plus the share of consumed electricity which is produced by RES) reaches a level of 1.8Mtoe by 2040. However, the share of RES in final energy consumption (ratio of total RES in the FEC as calculated above, over the final energy consumption reported in Figure 14.5) is reduced to around 30% by 2040 from the level of 37% in 2020.

Figure 14.6 **Albania: GHG emissions and GDP projections**



GHG emissions are projected to grow with a small de-coupling with respect to the GDP (Figure 14.6). Carbon intensity (expressed as the ratio of total GHG emissions in tons of CO_2eq per unit of Gross Inland Consumption) is decreasing slightly in the time horizon of the analysis reaching a value of 1.64 in 2040, mainly due to renewable energy shares in the gross inland consumption.

Bosnia-Herzegovina

Highlights

- Few available (quantitative) information / uncertainty
- Key factor: dominance of coal in the current (and expected) energy mix
- Share of RES over the gross final consumption among the lowest in the region

Key data sources

Country profile (for the very short-term and few projects and policy elements)

South East Europe Energy Outlook 2016/17 (for medium-long term consumption per capita trends)

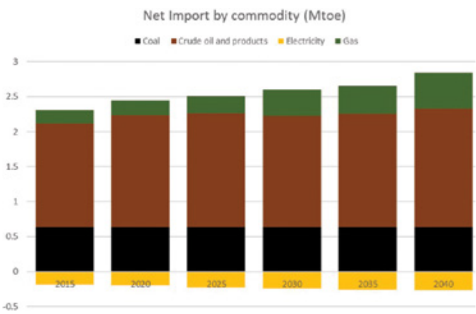
Author's adjustments (balance consistency-check along the energy chains)

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Bosnia-Herzegovina are reported below. Population (million); GDP (billion Euro).

BiH (WB6)	2015	2020	2025	2030	2035	2040
Population	3.52	3.49	3.45	3.42	3.33	3.25
GDP	14.6	17.1	19.74	22.77	25.64	28.87

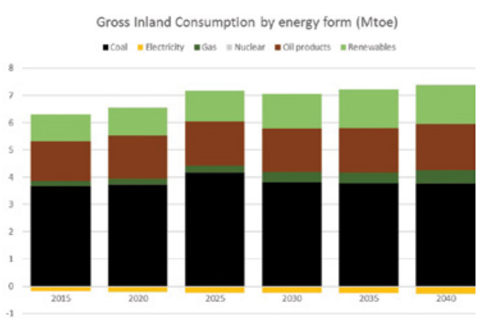
Bosnia-Herzegovina's net imported quantities are expected to increase up to around 2.5 Mtoe in the long-term with a gradual increase of oil & oil products import and extra import of natural gas from 2030 (two times the base year value in 2030, even more in 2040). Bosnia-Herzegovina is assumed to remain a net exporter of electricity over the analysed time horizon. The import dependency indicator is also expected to remain in the range 33% - 36% for all the periods.

Figure 14.7 **Bosnia-Herzegovina: Net Imports**



Gross Inland Consumption (GIC) in Bosnia-Herzegovina is expected to increase up to around 7 Mtoe over the analysed periods. The mix is not expected to significantly change, coal is seen to remain the key energy form of the system (always above 3.7 Mtoe in the medium-long term, similar values as in the base year), with limited/slow increase of renewable energy use (from around 1 Mtoe in 2020 to 1.45 Mtoe in 2040).

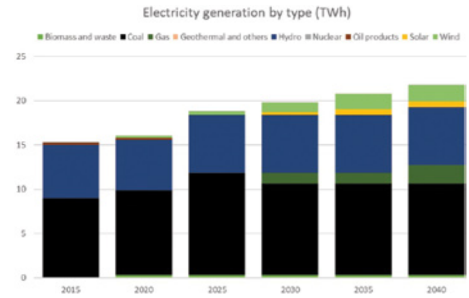
Figure 14.8 **Bosnia-Herzegovina: Gross Inland Consumption**



Electricity generation is projected to significantly increase from 16 TWh in 2020 to around 22 TWh in 2040, with a partial (limited) substitution of coal-fired plants with gas-fired generators starting from 2030.

In the short-term (by 2025), new coal-fired capacity (up to 750 MW) and new hydro power plants (up to 240 MW) are assumed to be installed in the system.

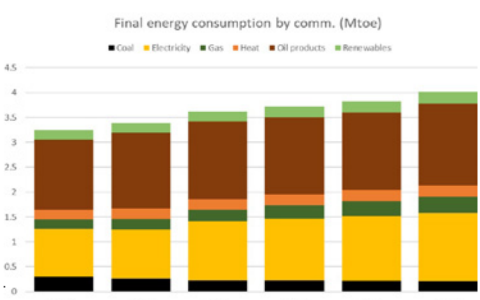
Figure 14.9 **Bosnia-Herzegovina: Gross Electricity generation by source**



Projected final consumptions in Bosnia-Herzegovina show a constant increase over the periods up to 4 Mtoe in 2040. In particular, electricity is expected to increase from less than 1 Mtoe in 2015-2020 to 1.4 Mtoe in 2040 (the fastest growth rate among the commodities in the final consumption). Coal consumption is expected to gradually reduce over the periods, on the other hand consumption of oil products, natural gas, and renewable are seen to slowly increase.

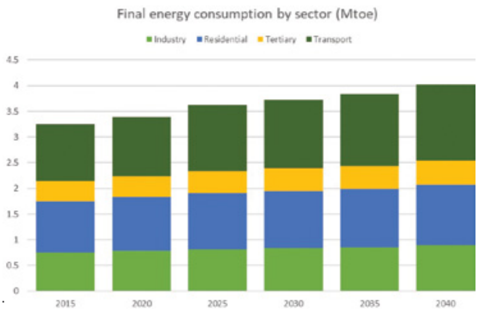
Few changes are assumed in the share of consumption by sector (the fastest increase in transportation, thus reflecting the sensitivity of this sector to the "economic" factors, against the decrease of population in the country). The share of RES in gross final consumption is expected to increase from around 17% in 2015 to 21% in 2040 (among the lowest in the region).

Figure 14.10 **Bosnia-Herzegovina: Final Energy Consumption by energy form**



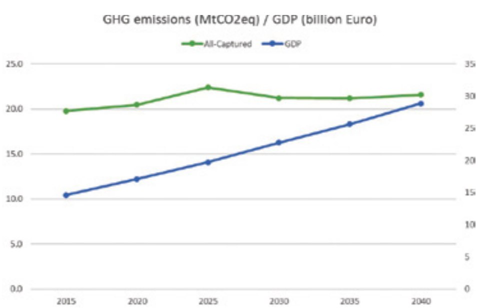
14

Figure 14.11 **Bosnia-Herzegovina: Final Energy Consumption by Sector**



Driven by the above mentioned elements (dominance of coal in the mix) projections show a general increase (+ 5% in 2040 with respect to 2020) of GHG emissions (excluding LULUCF) that is only partially mitigated/slowed-down by the penetration of natural gas in the power sector starting from 2030, and by the contribution of wind energy. Given the exogenous GDP values and the expected[4] GHG emission and GIC, the emission intensity of the economy (over GDP) reduces from well above 1000 to around 750 (tons CO_2eq / MEuro) and the carbon intensity (over GIC) from 3.2 to 3 (tons CO_2eq/ toe GIC), over the analysed periods.

Figure 14.12 **Bosnia-Herzegovina: GHG emissions and GDP projections**



Bulgaria

Highlights

- Existing measures are mainly oriented to the supply/generation side
- Key factor/uncertainty: nuclear energy
- Key factor/uncertainty: the rate of GHG emission is strongly affected by the reduction of coal consumption (mainly in the generation sector)

Key data sources

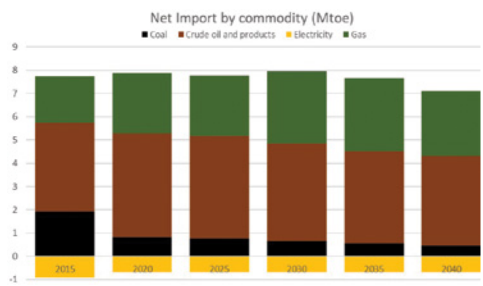
WEM Scenario, Integrated National Energy and Climate Plan (2020) - (Section B - Analytical basis)

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Bulgaria are reported below.

Bulgaria (EU)	2015	2020	2025	2030	2035	2040
Population (million)	7.18	6.95	6.78	6.61	6.45	6.30
GDP (billion Euro)	49.8	58.9	67.9	77.5	85.8	92.5

Bulgaria's imported quantities are projected to remain almost constant (around 8 Mtoe) until 2030, and reduce after 2030 due to higher efficiency (lower consumption) in the system. The trend of import mix mainly follows the changes in the supply side (less coal, more gas). Bulgaria is projected to remain a net exporter of electricity over the analysed time horizon. The import dependency indicator is also projected to remain in the range 36% - 40% for all the periods (relatively low, if compared with many EU MS).

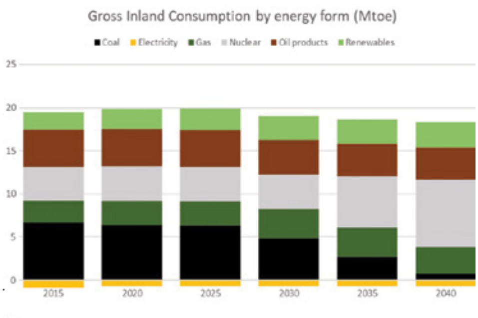
Figure 14.13 **Bulgaria: Net Imports**



Gross Inland Consumption (GIC) in Bulgaria is projected to slightly decline over the periods 2015 - 2040. The mix is also projected to change (in particular from 2030, and in the supply side), with a significant reduction of coal consumption (from 6.6 Mtoe in 2015 to <1 Mtoe in 2040) and the increase in nuclear energy use (from 4 Mtoe in 2015 to 7.8 Mtoe in 2040). Natural gas and renewable energy are also projected to increase at a relatively slow pace.

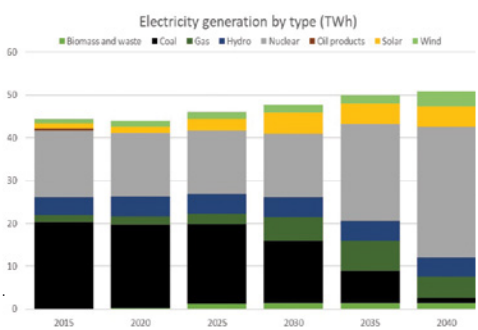
[4] Under such a "with existing measure" storyline

Figure 14.14 **Bulgaria: Gross Inland Consumption**



Electricity generation is projected to increase from 44 TWh in 2020 to 51 TWh in 2040, with the share of electricity generated by gas-powered plants expected to increase more than twofold between 2025 and 2030. A similar rate of growth is projected for solar power. But the key role is expected to be played by nuclear power (especially from 2035) when a new nuclear plant is included in the generation stock.

Figure 14.15 **Bulgaria: Gross Electricity generation by source**



Projected final consumptions in Bulgaria show a slight increase over the periods, driven by the expected economic growth, up to 10.4 Mtoe. In particular, electricity is projected to increase from 2.5 Mtoe in 2015 to 3.3 Mtoe in 2040, while few changes are expected in the share of consumption by sector (the fastest increase is expected in the residential sector and in transportation, thus reflecting the impact of the economic factors against the decrease of population in the country). No relevant structural changes of the economy are assumed/ foreseen, leading to slow and smooth dynamics for industry and tertiary consumptions.

The share of RES in gross final consumption is projected to increase from around 16.7% in 2015 to 23.8% in 2040.

Figure 14.16 **Bulgaria: Final Energy Consumption by energy form**

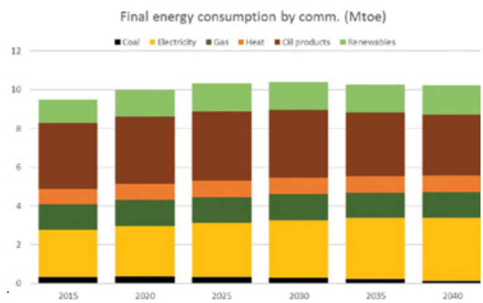
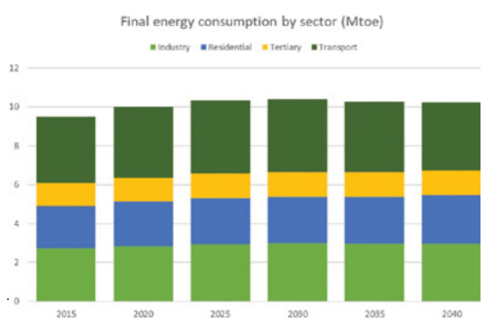


Figure 14.17 **Bulgaria: Final Energy Consumption by Sector**

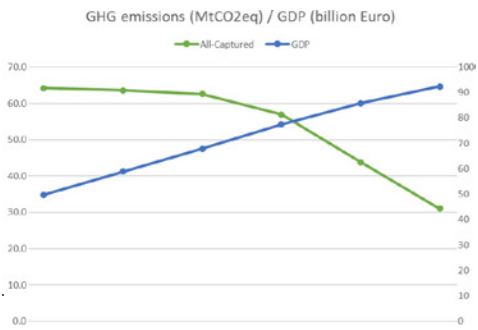


The projections show that, by 2030, GHG emissions (excluding LULUCF) will decrease by 15.4 % as compared to emission levels in 2015, and further decrease after 2030 as a consequence of the gradual reduction of coal use (in the power sector)[5].

Given the exogenous GDP values and the projected GHG emission and GIC, the emission intensity of the economy (over GDP) significantly reduces from above 1000 to around 350 (tons CO_2eq / MEuro), and the carbon intensity (over GIC) from 3.4 to 1.75 (tons CO_2eq/ toe GIC), over the analysed periods.

[5] Emissions after 2030 are not explicitly reported in the official documents, and therefore are calculated based on the the GIC mix and trends.

Figure 14.18 **Bulgaria: GHG emissions and GDP projections**



In the National Energy Climate Plan, Bulgaria reports some high-level results of an "additional/ planned" measure scenario (WAM), based on which some small "extra" emission reductions can be obtained (extra -1% of reduction with respect to the value of 1990 compared to the existing measure projections in 2030, also equivalent to around -5% in 2030 with respect to the "existing measure" projection in the same period).

Assessment of the final national energy and climate plan of Bulgaria

National contributions	Assessment of the 2030 ambition level
National target/contribution for renewable energy: • Share of energy from renewable sources in gross final consumption of energy (%)	Adequate
National contribution for energy efficiency: • Primary energy consumption • Final energy consumption	 Low Very low

Sources: European Commission, Energy statistics, Energy datasheets: EU countries; European Semester by country; Bulgaria's final national energy and climate plan

Cyprus

Highlights

- Power sector transformation: 70% of the electricity generated by RES by 2040.
- Electrification of heating/cooling and transport
- Significant reduction of emissions intensity.
- Cyprus switches from a net energy importer to a net exporter after 2030.

Key data sources

WEM Scenario, Integrated National Energy and Climate Plan (2020).

Impact Assessment of the Planned Policies and Measures of the NECP (2019).

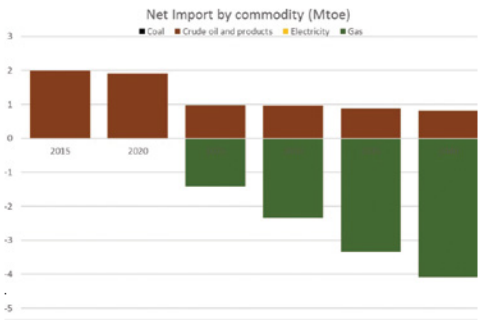
The projected evolution of the main exogenous factors influencing the energy system and GHG emissions developments of Cyprus are reported below.

Cyprus (EU)	2015	2020	2025	2030	2035	2040
Population (million)	0.9	0.9	0.9	0.9	0.9	0.9
GDP (billion Euro)	16.5	21.8	24.6	27.2	30.0	33.1

The only domestic energy sources in Cyprus are renewable energy and a very small amount of industrial waste. All other energy commodities (mainly oil products) are currently being imported (Figure 14.19). A major change in the net energy imports is expected to take place by 2030[6], when the export of natural gas from the offshore fields is expected to reach 1.4Mtoe and it is expected that exports of gas will increase three-fold until 2040. The imports of oil products in 2040 are expected to be reduced to half the level of 2020, due to their substitution by gas in the power sector and by biofuels and electricity in transport.

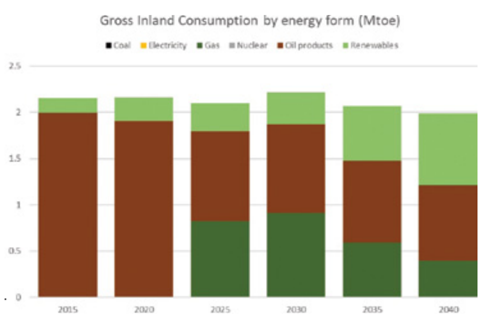
[6] The net import projections for natural gas are taken from the EU Reference 2016 Scenario (https://ec.europa.eu/energy/data-analysis/energy-modelling/eu-reference-scenario-2016_en) , since the NECP does not include these figures.

Figure 14.19 **Cyprus: Net Imports**



Gross Inland consumption in Cyprus is projected to remain relatively stable in the time horizon until 2030 with a tendency to be reduced to a level of 1.9Mtoe by 2040. However, there is a noticeable change in the relative contribution of the different energy commodities to the GIC, since oil products are replaced to a large extend by renewable energy and natural gas. Oil products contribute almost 90% of the GIC in 2020 and this share is reduced to 40% by 2040. At the same time, the share of renewable energy (which is mainly solar plus a modest amount of wind energy in the case of Cyprus) increases to cover almost 40% of the GIC by 2040, reaching 0.8Mtoe.

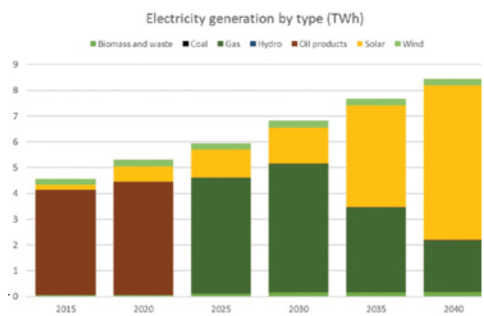
Figure 14.20 **Cyprus: Gross Inland Consumption**



The power sector in Cyprus undergoes a complete transformation until 2040 (Figure 14.21). The oil dominated system which is still in place today is transformed to a system based on natural gas by 2030, since the expected gas extraction in the offshore fields will be utilised mainly in electricity generation.

A second transformation of the power system takes place between 2030 and 2040, where the generation from gas is replaced to a large extent by generation from solar plants. A total of 6TWh is projected to be generated by solar energy in 2040, with more than half coming from concentrated solar thermal plants and the remaining from PV installations. According to the NECP, the projected power system includes storage technologies like Li-Ion batteries and pumped hydro plants. The scenario includes, 700MW of concentrated solar power plants, 1630MW of PV installations, 198MW of wind turbines and 64MW of biogas fired plants in 2040. The storage options include 130MW of pumped hydro plants and 179MW of Li-Ion batteries. The total electricity generation increases by almost 50% between 2015 and 2030, reaching a total of 6.8TWh. A further increase of 24% is observed from 2030 to 2040 with a total generation of 8.4TWh.

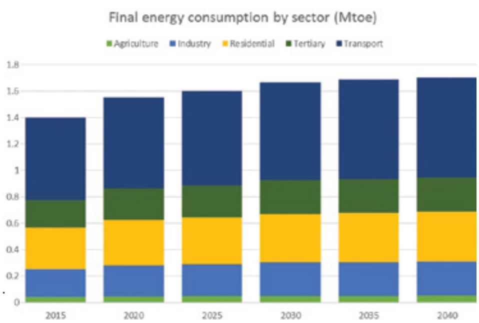
Figure 14.21 **Cyprus: Gross Electricity generation by source**



Final energy consumption is projected to increase by 20% between 2015 and 2030, reaching 1.7Mtoe. In the period from 2030 to 2040 an increase of almost 7% is projected to almost 1.8Mtoe. The shares of the different sectors in the FEC remain almost constant for the whole time-horizon, with the residential sector covering 22% and transport 45% of the total. A noticeable shift in the energy commodities consumed at the final energy level can be seen in Figure 14.22. The share of oil products is considerably reduced from 67% in 2015 to 48% in 2040, while the share of electricity increases from 25% in 2015 to 40% in 2040.

This shift is due to the electrification in the transport sector and the electrification of heating and cooling. Renewable energy in the final energy consumption also increases, mainly due to the use of solar energy for heating and cooling, covering 12% of the total by 2040.

Figure 14.22 **Cyprus: Final Energy Consumption by Sector**



The Renewable Energy in FEC, including the electricity generated by renewables, reaches 0.73Mtoe in 2040 increasing almost five-fold from 2015 (starting from a value of 0.15Mtoe). According to the country's NECP, the share of RES in the electricity generation reaches almost 70% by 2040, while the share of RES in heating and cooling reaches 50%, mainly due to the use of solar technologies. The share of RES in transport reaches 27%, due to the contribution of renewable electricity and a small contribution from biofuels. This leads to a total share of RES in the Gross Final Energy Consumption at the level of 20% in 2030 and 40% by 2040 starting from 15% in 2020.

Figure 14.23 **Cyprus: Final Energy Consumption by energy form**

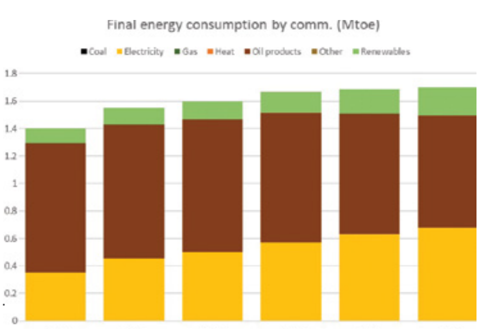
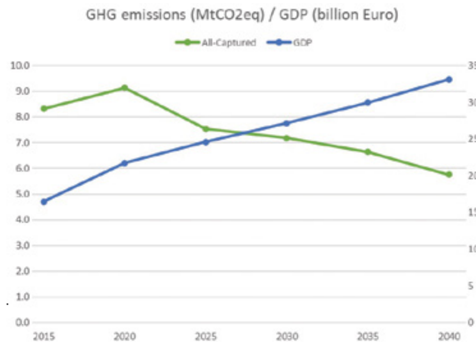


Figure 14.24 **Cyprus: GHG emissions and GDP projections**



As a result of the changes in the energy system described above, the absolute value of GHG emissions decreases in the whole period from 2020 to 2040, to a level of 5.7Mt CO_2eq. Carbon intensity reaches a value of 2.80tonCO_2eq/toe GIC in 2040. A distinct de-coupling between GHG emissions and GDP is clear in Figure 14.24, and the emissions intensity per unit of GDP reduces considerably from 505 tons of CO_2eq per million Euro in 2015 to 174 tons of CO_2eq per million Euro in 2040. In the National Energy Climate Plan, Cyprus reports results of an "additional/planned" measures scenario, named "Planed Policies and Measures" (PPM). In this scenario FEC is projected to reduce by 10% compared to the WEM scenario in 2030 due to energy efficiency measures. The reported emissions in 2030 are 16.4% lower than in the WEM scenario and the share of RES in the GFEC is increased to 30.7% (from 20.7% in WEM).

Assessment of the final national energy and climate plan of Cyprus

National contributions	Assessment of the 2030 ambition level
National target/contribution for renewable energy:	
• Share of energy from renewable sources in gross final consumption of energy (%)	Slightly below
National contribution for energy efficiency:	
• Primary energy consumption	Low
• Final energy consumption	Very low

Sources: European Commission, Energy statistics, Energy datasheets: EU countries; European Semester by country; Cyprus's final national energy and climate plan

Croatia

> ***Highlights***
> - Existing measures are mainly oriented to the supply/generation side
> - Limited "quantitative" information related to the demand side --> data required some processing/integration
> - Key factor: deployment of wind energy

Key data sources

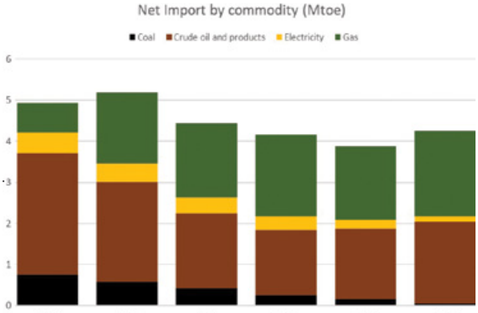
WEM Scenario, Integrated National Energy and Climate Plan (2020) - (Section B - Analytical basis)

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Croatia are reported below.

Croatia (EU)	2015	2020	2025	2030	2035	2040
Population (million)	4.24	3.98	3.87	3.76	3.64	3.53
GDP (billion Euro)	48.7	58.6	63.4	68.1	74.3	80.5

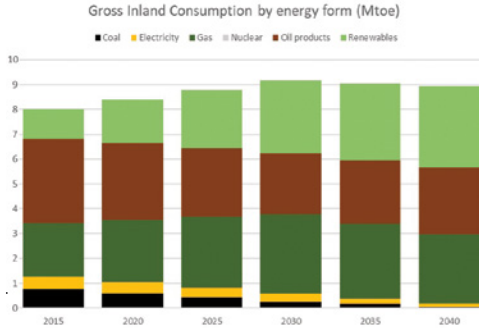
Evolution of net import of energy[7] in Croatia is mainly driven by the expected contribution of the domestic supply. Own-supply first increases and then declines sharply starting from 2040 due to a decline in domestic oil and natural gas production (under the existing measure storyline, existing fields are assumed to stop operating after 2035, and no new fields developed). Therefore, Croatia is projected to remain a net importer of energy over the entire analysed horizon. The import dependency indicator is projected to evolve accordingly, from about 60% in 2020 down to 45% in 2030, and up again to around 48% in 2040.

Figure 14.25 **Croatia: Net Imports**



Gross Inland Consumption (GIC) in Croatia[8] is projected to peak in 2030 up to 9.1 Mtoe, and to slightly decrease towards the end of the analysed period. The mix is also projected to slightly change with an almost complete decline of coal use, an increasing trend of renewable energy (up to 3.2 Mtoe in 2040) and of oil products (up to 2.7 Mtoe in 2040), and a quite stable expected consumption of natural gas (around 3 Mtoe).

Figure 14.26 **Croatia: Gross Inland Consumption**



Electricity generation is projected to increase from 12.2 TWh in 2020 to 18.2 TWh in 2040, with a complete phase-out of coal-fired generators and a significant increase of electricity from intermittent renewable (up to 6 TWh from solar and wind in 2040) and biomass (up to 1.6 TWh in 2040). By 2030, it is also expected the construction of 2 large hydropower plants (+1 pumped storage hydropower plant) that will also increase the generation from hydro. Overall, no relevant changes in the total gas-fired stock[9] are expected/projected over the periods thus leading to a quite constant contribution of gas in the generation of electricity.

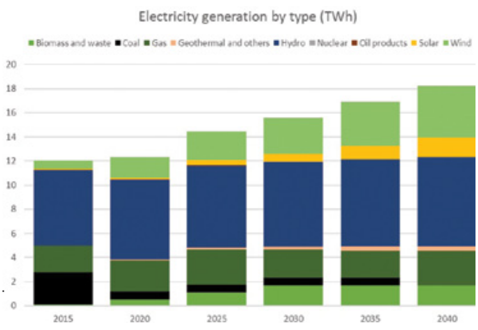
Nuclear generation is reported to be zero, though a power plant in Slovenia is owned at 50% by both the countries).

[7] Values are calculated by difference: Gross Inland Consumption – Expected domestic production.

[8] In the official submission (NECP, chapter 4), only values for "2" milestones are reported (2030 and 2040). Figures for the intermediate periods are calculated by the authors based on the "trends" and balance consistency checks.

[9] Expected gas-fired electricity generation capacity is projected to follow some "ups" and "downs" (likely due to some repowering/refurbishment/substitution of the units, or simply to minor simulation/modelling issues). 50% of the capacity is expected to be for cogeneration.

Figure 14.27 **Croatia: Gross Electricity generation by source**



Projected final consumptions[10] in Croatia show a slight increase until 2030 (above 7 Mtoe), and slowly decline afterwards (to around 6.8 Mtoe in2040). In particular, natural gas consumption (thermal needs for building) is projected to follow the same dynamics, with an increase in consumption up to 1.9 Mtoe in 2030 and a drop to 1.6 Mtoe in 2040, thus reflecting the decline in population and the energy efficiency improvement in the sector. Renewable energy are projected to gradually increase to about 1.3 Mtoe in 2040 (in particular renewables for "thermal" energy service demands), while coal is completely excluded from the final uses starting from 2035.

The share of RES in gross final consumption is projected to gradually increase from around 26% in 2020 to 37.5% in 2040.

Figure 14.28 **Croatia: Final Energy Consumption by energy form**

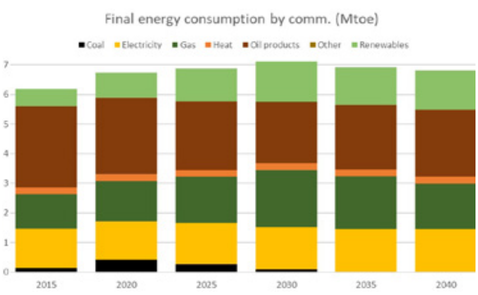
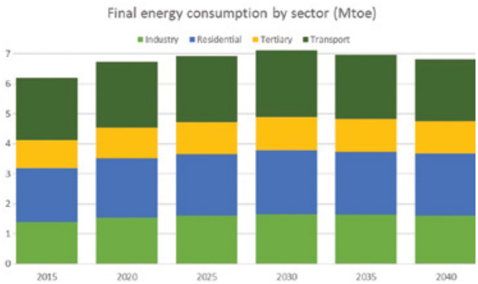
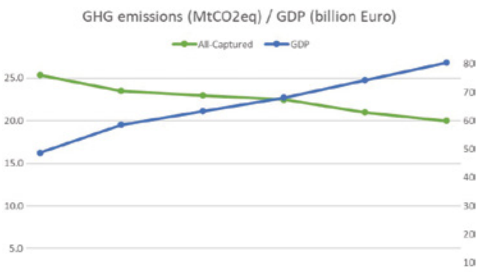


Figure 14.29 **Croatia: Final Energy Consumption by Sector**



The projections show that, by 2030, GHG emissions (excluding LULUCF) will decrease by 12% as compared to emission levels in 2015, and further decrease down to 20 $MtCO_2eq$ in 2040. The largest reduction is expected from the "energy industry" sector (different mix and higher efficiency in the electricity generation). Given the exogenous GDP values and the projected GHG emission and GIC, the emission intensity of the economy (over GDP) reduces from above 520 to around 250 (tons CO_2eq / MEuro) and the carbon intensity (over GIC) from 3.1 to 2.2 (tons CO_2eq/ toe GIC), over the analysed periods.

Figure 14.30 **Croatia: GHG emissions and GDP projections**



In the National Energy Climate Plan, Croatia reports some high-level results of an "additional/planned" measure scenario (WAM), based on which some "extra" emission reductions can be obtained leading to the following emissions level: 20.5 $MtCO_2eq$ (in 2030), 18 $MtCO_2eq$ (in 2040).

[10] Official submissions do not report a complete breakdown of the final consumption across the energy forms and of the sectors. The breakdown by commodity is based on authors' elaboration of the few semi-qualitative available information, and of a consistency check to close the energy balance (supply > use for generation/transformation > final consumption).

Assessment of the final national energy and climate plan of Croatia

National contributions	Assessment of the 2030 ambition level
National target/contribution for renewable energy:	
• Share of energy from renewable sources in gross final consumption of energy (%)	Sufficiently ambitious
National contribution for energy efficiency:	
• Primary energy consumption	Low
• Final energy consumption	Low

Sources: European Commission, Energy statistics, Energy datasheets: EU countries; European Semester by country; Croatia's final national energy and climate plan

Greece

Highlights

- Lignite fired power plants are shut down after 2025.
- Renewable energy generates 79% of electricity by 2040.
- RES share in GFEC reaches 41% by 2040.
- Carbon intensity is reduced by 40% between 2015 and 2040.

Key data sources

National Energy and Climate Plan (2019)
Basic Scenario results for the NECP (2019)

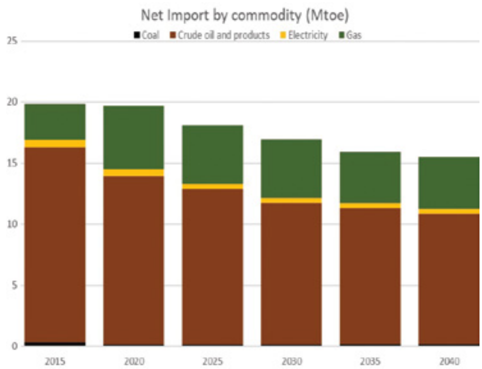
The projected evolution of the main exogenous factors influencing the energy system and GHG emissions developments of Greece are reported below.

Greece (EU)	2015	2020	2025	2030	2035	2040
Population (million)	10.9	10.6	10.3	10.0	9.7	9.5
GDP (billion Euro)	184.8	200.4	219.7	240.2	262.6	282.9

According to the National Energy and Climate Plan of Greece, the country continues to be a net energy importer for the whole period until 2040, however the import dependency is reduced from 78% in 2020 to 64% in 2040. Net imports are dominated by oil products (69% of net imports in 2040) in order to cover the final consumption.

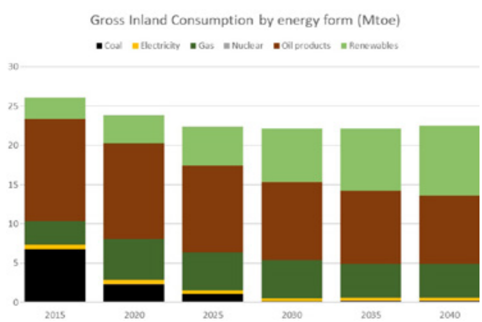
Natural gas imports correspond to 27% of total net imports in 2040 and electricity imports are almost 3% (5 TWh) in 2040.

Figure 14.31 **Greece: Net Imports**



According to the projections a major fuel switch is expected to take place in the period after 2025, when all the lignite fired power plants will shut down. The GIC is projected to fall from 26Mtoe in 2015 to 22.5Mtoe in 2040 (Figure 14.32). A reduction of 33% is observed in oil products from 2015 to 2040 while in the same period renewable energy increases by 230% reaching almost 9Mtoe in 2040 and the quantity of natural gas increases by 1.5 times reaching 4.3Mtoe.

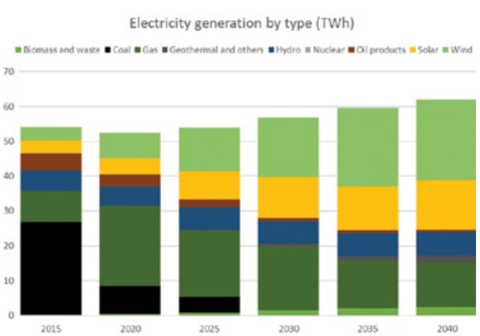
Figure 14.32 **Greece: Gross Inland Consumption**



The power sector of Greece is projected to undergo a transformation, switching from a system heavily based on domestic lignite (49% of the gross generation in 2015), to a system dominated by renewable energy (79% of the gross generation in 2040) supported by gas fired power plants (20% of gross generation in 2040).

The gross electricity generation increases from 54TWh in 2015 to 62TWh in 2040. Variable renewables (wind and solar) contribute a total of 60% in the electricity generation in 2040. More specifically, wind turbines contribute 37% (23TWh) and PV installations 23% (14TWh) respectively in 2040. For the reliable operation of the power system and the minimisation of curtailment, a total of 1.4GW of new centralised storage systems (batteries and pump storage) is required, according to the NECP.

Figure 14.33 **Greece: Gross Electricity generation by source**



The final energy consumption is reduced by 4% from 2015 to 2040, stabilising at the level of 17.2Mtoe (Figure 14.34). The structure of FEC remains rather stable, with transport remaining the sector with the largest share of consumption (40% of FEC) and the residential sector having the second largest share of consumption (25% in 2040). The services sector increases slightly its share from 13% in 2015 to 15% in 2040 and is the only sector with an increase in the level of energy consumed (from 2.4Mtoe in 2015 to 2.6Mtoe in 2040).

Regarding the energy commodities which are consumed, as can be seen in Figure 14.34, the share of oil products in FEC reduces from 59% in 2015 to 38% in 2040, while the shares of natural gas, electricity and renewables increase over the same period. The share of natural gas doubles from 6% in 2015 to 12% in 2040 reaching 2Mtoe, similarly to the share of RES which increases from 8% to 16% reaching 2.8Mtoe in 2040. The share of electricity reaches 31% of FEC in 2040 and a level of 62TWh.

Figure 14.34 **Greece: Final Energy Consumption by Sector**

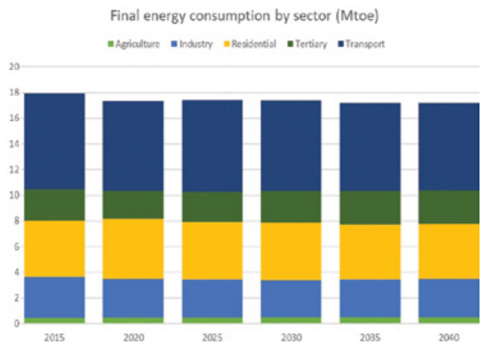
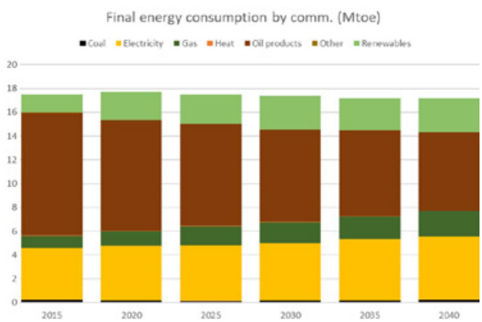


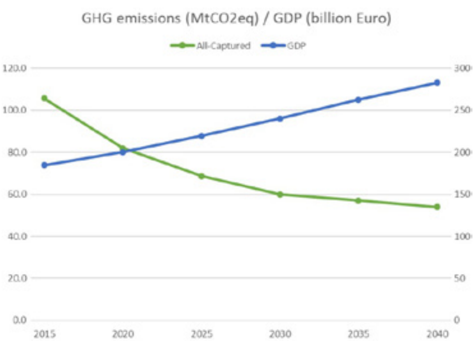
Figure 14.35 **Greece: Final Energy Consumption by energy form**



The share of RES in Gross Final Energy Consumption is reported in the NECP to reach 35% in 2030 and a level of 41% by 2040. The share of RES in heating and cooling reaches the level of 43% in 2040 while the share of RES in final consumption in transport increases from 6.6% in 2020 to 19% in 2030 and then doubles to 41% by 2040 (using the methodology of the RE directive).

A clear decoupling between GHG emissions and economic activity in the country can be seen in Figure 14.36. Carbon intensity expressed as the ratio of GHG emissions (tCO_2eq) over Gross Inland Consumption is reduced by 40% between 2015 and 2040, reaching a level of 2.4 (tCO_2eq)/(toe GIC). The main reason for this reduction is the large penetration of renewable energy in the power sector and in the final energy consumption and the shutdown of the lignite fired power plants. The emission intensity expressed as the ratio of tons of CO_2eq per unit of GDP is reduced almost three-fold in the period under consideration, reaching 190 tCO_2eq/million Euros in 2040.

Figure 14.36 **Greece: GHG emissions and GDP projections**



In the National Energy Climate Plan, Greece reports only one scenario which is presented above and is interpreted as a scenario with existing and planned measures to achieve the sufficiently ambitious targets which are set.

Assessment of the final national energy and climate plan of Greece

National contributions	Assessment of the 2030 ambition level
National target/contribution for renewable energy: • Share of energy from renewable sources in gross final consumption of energy (%)	Sufficiently ambitious
National contribution for energy efficiency: • Primary energy consumption • Final energy consumption	Modest Low

Sources: European Commission, Energy statistics, Energy datasheets: EU countries; European Semester by country; Greece's final national energy and climate plan.

Kosovo

Highlights

- Limited (up-to-date) information is available
- High uncertainty about gasification (start date and market share)
- Key factor: coal is expected to keep playing a major role in the system (electricity generation)
- Coherence of import/export with the rest of the region to be verified.

Key data sources

For the short term: Energy Strategy of the Republic of Kosovo 2017 - 2026

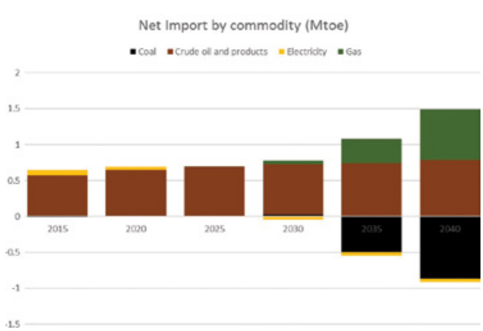
For the longer term: trend from the South East Europe Energy Outlook 2016/17

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Kosovo are reported below. Population (million); GDP (billion Euro).

Kosovo (WB6)	2015	2020	2025	2030	2035	2040
Population (million)	1.8	1.9	1.9	1.9	1.9	1.9
GDP (billion Euro)	5.1	6.4	7.7	9.2	10.9	13.0

The energy import/export pattern in Kosovo is expected to significantly change after 2030, when export of domestic coal is foreseen to become a relevant component of the balance[11], and natural gas is assumed to be supplied to the system. Kosovo is also expected to potentially become a net exporter of electricity (30-40 ktoe) after 2025-2030, and to remain strongly dependent from the oil product import (up to 0.8 Mtoe in 2040). Overall, the import dependency indicator is projected to reduce accordingly (driven by the large amount of coal export), from around 25% in 2020 to 17% in 2040.

Figure 14.37 **Kosovo: Net Imports**

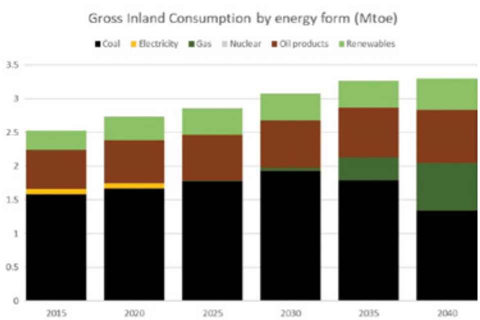


Gross Inland Consumption (GIC) in Kosovo is expected to remain dominated by coal at least until 2030 (up to 1.9 Mtoe in 2030) with a partial substitution / penetration of natural gas in the longer term (up to 0.7 Mtoe in 2040).

[11] It is not clear though, the degree to which such amount of coal is actually demanded from other countries of the region (as for some countries coal imports are projected to decline and in few cases only, for instance in North Macedonia, coal import is projected to increase over the periods).

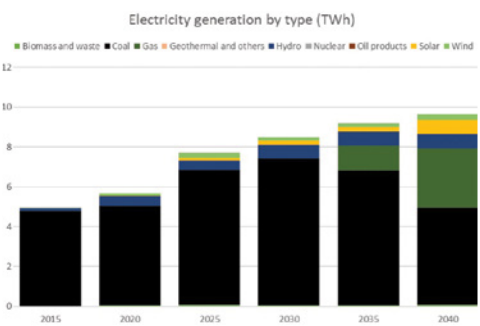
Total gross inland consumption is expected to grow from 2.7 Mtoe in 2020 to 3.2 Mtoe in 2040 with a relatively slow increase in renewable energy consumption (from 0.35 Mtoe in 2020 to around 0.46 Mtoe in 2040).

Figure 14.38 **Kosovo: Gross Inland Consumption**



Electricity generation is projected to increase from 5.6 TWh in 2020 to 9.6 TWh in 2040; the largest part of the increase is expected to be generated by coal (up to 7.3 TWh in 2030) and natural gas after 2030 (up to 3 TWh in 2040). A gradual and slow penetration of renewable energy in the mix (in particular solar energy) is expected not earlier than 2035-2040 (up to 0.7 TWh).

Figure 14.39 **Kosovo: Gross Electricity generation by source**



Projected final consumptions in Kosovo show a significant increase over the periods, up to 1.95 Mtoe in 2040[12]. In particular, electricity demand is expected to increase from 0.4 Mtoe in 2020 to almost 0.55 Mtoe in 2040, oil products from 0.65 Mtoe to 0.79 Mtoe, and natural gas to be part of the mix starting from 2030 (for up to 0.14 Mtoe in 2040). Renewable energy are expected to remain at the current level of consumption (around 0.28 Mtoe) over the analysed periods. At sectoral level, faster increase of consumption is expected in industry and transport sector which result the most sensitive (to the assumed GDP growth) activities.

The share of RES in gross final consumption is projected to slightly decline from the level of 22% to around 20% (among the lowest in the region, as the rate of the RES growth is slower than the growth rate of consumption).

Figure 14.40 **Kosovo: Final Energy Consumption by energy form**

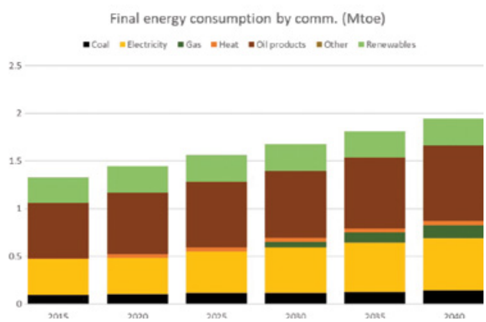
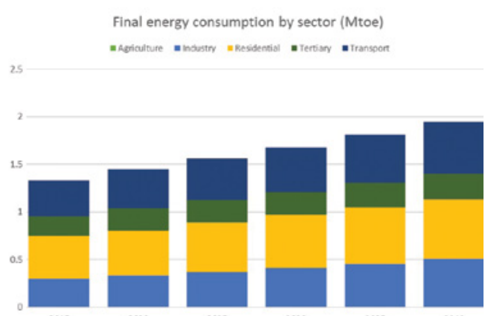


Figure 14.41 **Kosovo: Final Energy Consumption by Sector**

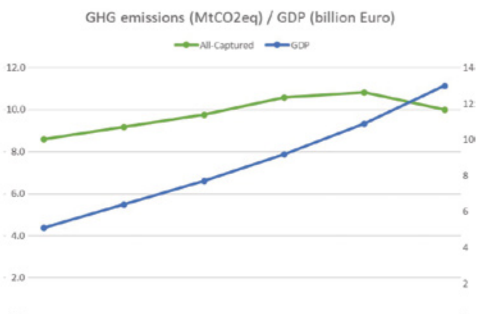


Driven by the high rate of coal use, the expected[13] evolution of the GHG emissions (excluding LULUCF) for Kosovo shows an increasing trend over the period 2020-2035 (up to 10.8 MtCO_2eq). The turning point in 2035 is caused by the largest penetration of natural gas in the electricity generation mix (to partially substitute

12 Kosovo in one of the few countries in the region with a "non-negative" expected population growth.
12 Under such a "with existing measure" storyline.
14 GHG emissions are calculated on the basis of the dynamics of the GIC, LULUCF are excluded.

coal)[14]. Given the exogenous GDP values, and the projected GHG emission and GIC, the emission intensity of the economy (over GDP) reduces from around 1500 to around 770 (tons CO_2eq /MEuro) in 2040, and the carbon intensity (over GIC) from 3.4 to 3.1 (tons CO_2eq/ toe GIC), over the analysed periods.

Figure 14.42 **Kosovo: GHG emissions and GDP projections**



Montenegro

Highlights

- High dependency on the country's hydrological situation and the water level in the rivers
- High share of biomass in the final consumption
- Key scenario factor: coal phase-out by 2030
- Key scenario factor: limited / no gasification of the demand side

Key data sources

The "Energy Policy of Montenegro until 2030" is the main strategic document. It was adopted in 2014, and it is therefore already reflected into the projections prepared in the framework of the South East Europe Energy Outlook 2016/17, that remains the key source of data of this paragraph.

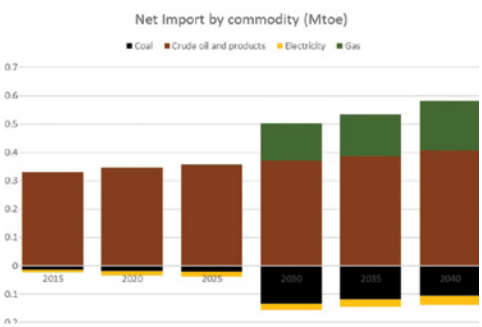
The country-profile provides a few statistical information (for 2018-2019) that are used to flag potential issues/gaps/space for improvements for future (detailed) modelling works, but are not sufficient to describe a complete and coherent (alternative to the South East Europe Energy Outlook 2016/17) evolution of the energy system.

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Montenegro are reported below. Population (million); GDP (billion Euro).

Montenegro (WB6)	2015	2020	2025	2030	2035	2040
Population (million)	0.6	0.6	0.6	0.6	0.6	0.6
GDP (billion Euro)	3.4	3.9	4.5	5.0	5.7	6.3

The energy import/export pattern in Montenegro is expected to significantly change after 2025, when export of domestic coal is foreseen to become a relevant component of the balance , and natural gas is assumed to be supplied to the system. Montenegro is also expected to remain strongly dependent from the oil product import (up to 0.4 Mtoe in 2040). Overall, the import dependency indicator is projected to increase accordingly (mainly driven by the large amount of gas import), from around 30% in 2020 to around 40% in 2040.

Figure 14.43 **Montenegro: Net Imports**

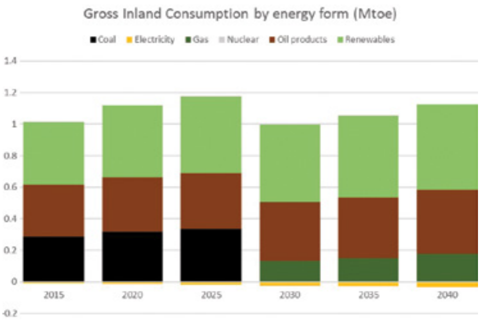


Gross Inland Consumption (GIC) in Montenegro is expected to significantly change in 2030 with a complete substitution of coal with natural gas (up to 0.2 Mtoe in 2040). Total gross inland consumption is expected to decline to 1 Mtoe in 2030[16] and increase again afterwards up to 1.1 Mtoe in 2040 (with a relatively slow increase in renewable energy consumption in the demand side); thus, revealing the increase in energy demand of the country.

[15] It is not clear though, the degree to which such amount of coal is actually demanded from other countries of the region (as for some countries coal imports are projected to decline and in few cases only, for instance in North Macedonia, coal import is projected to increase over the periods).

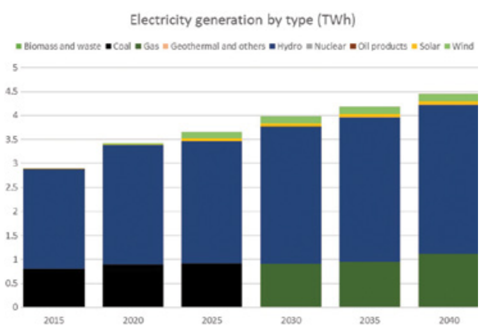
[16] The underlying assumption is that gas-fired plants are "significantly" more efficient than old coal power plants.

Figure 14.44 **Montenegro: Gross Inland Consumption**



Electricity generation is projected to increase from around 3.5 TWh in 2020[17] to 4.5 TWh in 2040; the largest part of the increase is expected to be produced by hydro power (projected to generate up to 3.1 TWh in 2040). A gradual and slow penetration of renewable energy in the mix (in particular wind energy) is expected to generate up to 0.23 TWh in 2040. The shut-down of the coal-fired stock is assumed to happen in 2030, with natural gas generating the same, constant, amount of electricity of the existing coal-fired plants.

Figure 14.45 **Montenegro: Gross Electricity generation by source**



Projected final consumptions in Montenegro show a significant increase over the periods, from 0.8 Mote in 2020 up to 1 Mtoe in 2040. In particular, electricity demand is expected to increase from 0.2 Mtoe in 2020[18] to above 0.3 Mtoe in 2040, oil products from 0.35 Mtoe to 0.4 Mtoe, with a very limited share of natural gas[19]. Renewable energy are expected to remain at the current level of consumption (around 0.25 Mtoe) over the analysed periods. At sectoral level, faster increase of consumption is expected in residential and transport sector which result the most sensitive (to the assumed GDP growth) activities. The share of RES in gross final consumption is projected to remain in the range of 48% - 50% over the periods (increase of final consumption is offset by the large increase of hydropower).

Figure 14.46 **Montenegro: Final Energy Consumption by energy form**

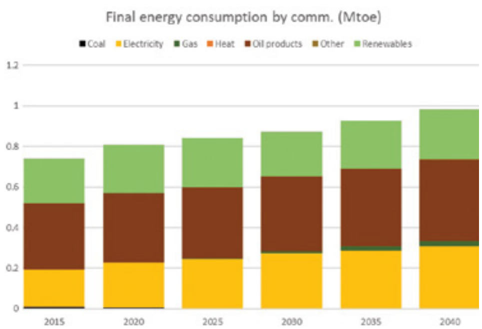
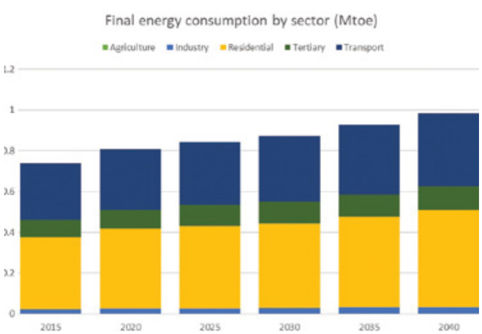


Figure 14.47 **Montenegro: Final Energy Consumption by Sector**



The phase-out of coal in 2030 is the key driver for the expected evolution of the GHG emissions (excluding LULUCF) of Montenegro.

17 Ministry of Economy of Montenegro in its Energy balance for 2020 has planned for a total electricity of 3454 GWh, out of which 1823 GWh from HPP, 312 GWh from wind farms, 2 GWh from solar plants and 1317 GWh from thermal power plant. While the total value is quinte in line with the Outlook, the share of coal and hydro differ from the figures presented here.

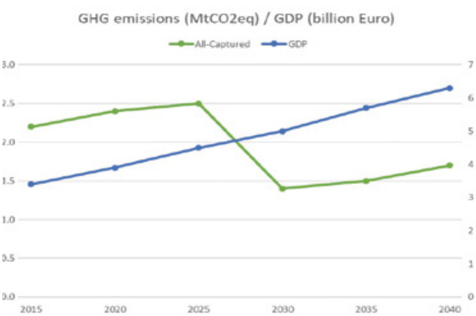
18 Country profile reports an estimate of electricity consumption for 2019/2020 of around 12.7 PJ (equivalent to 300 ktoe, significantly greater than the 220 ktoe reported in the Outlook). Even considering the losses, there might be a large "gap" between the sources to further investigate.

19 Country profile reports an estimate of natural gas (supplied via the planned project of the Ionian Adriatic Pipeline (IAP)) final consumption of 46million of m3 in 2030 (equivalent to around 40 ktoe). This is significantly greater than the figure reported in the Outlook for 2030 (around 10 ktoe).

After 2030 (once the space of changes offered by "fuel switch" in the power sector has been used), emissions are projected to grow, thus reflecting the increasing energy demand and the limited energy efficiency improvements and electrification of the demand side of the "with existing measure" storyline.

Given the exogenous GDP values, and the projected GHG emission and GIC, the emission intensity of the economy (over GDP) reduces from around 650 to around 270 (tons CO_2eq / MEuro) in 2040, and the carbon intensity (over GIC) from 2.2 to 1.6 (tons CO_2eq/ toe GIC), over the analysed periods.

Figure 14.48 **Montenegro: GHG emissions and GDP projections**



North Macedonia

Highlights

- Existing measures are mainly oriented to the supply/generation side
- Limited changes in the demand side energy mix (coal consumption is projected to increase)
- "Additional" measures are projected to (potentially) significantly change the dynamics of GHG emission, but are mainly focus on the supply side (decommissioning of the large coal-fired power plant)

Key data sources

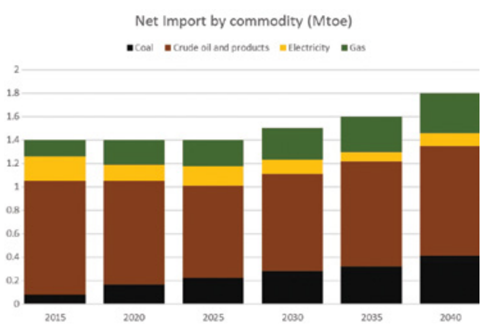
WEM Scenario, Integrated National Energy and Climate Plan (2020) - (Section B - Analytical basis) - DRAFT submitted to the Energy Community Secretariat

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Montenegro are reported below. Population (million); GDP (billion Euro).

North Macedonia (WB6)	2015	2020	2025	2030	2035	2040
Population (million)	2.1	2.1	2.1	2.1	2.0	2.0
GDP (billion Euro)	7.9	9.7	11.4	13.8	16.4	19.3

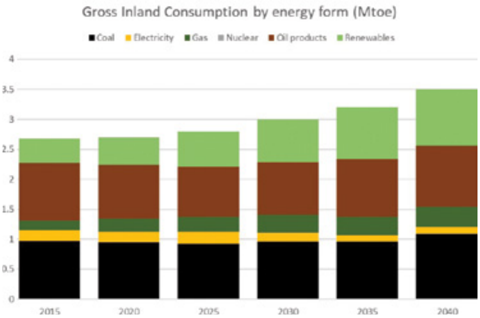
Net import of energy in North Macedonia is projected to increase (up to 1.8 Mtoe) in 2040 mainly driven by the increase of natural gas demand in the system. Despite the need of electricity import is mitigated by the increase of domestic production from renewable energy in the medium term, North Macedonia is still projected to remain a net importer of electricity over the analysed horizon (around 100 ktoe in 2040). Import of coal is also projected to increase up to 400 ktoe in 2040. Overall, the import dependency indicator is projected to remain constant at the level of the base year (in a range from 50% - 52%).

Figure 14.49 **North Macedonia: Net Imports**



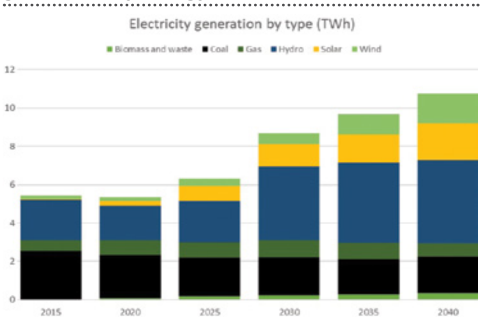
Gross Inland Consumption (GIC) in North Macedonia is projected to increase up to 3.5 Mtoe in 2040. The mix is projected to slightly change (in particular after 2030) with the increase of renewable energy (up to 0.95 Mtoe in 2040) and of natural gas (up to 0.35 Mtoe in 2040). Coal is expected to play a relevant role over the entire analysed horizon, with a consumption always above 0.9 Mtoe.

Figure 14.50 **North Macedonia: Gross Inland Consumption**



Electricity generation is projected to significantly increase from 5.4 TWh in 2020 to 10.7 TWh in 2040. The most important (expected) change in the mix is the larger contribution of hydro energy starting from 2025 (expected to generate up to 4.3 TWh in 2040). Solar and wind generation are also projected to increase up to 1.7 TWh in 2030 and 3.4 TWh in 2040[20]. No significant increase in generation from fossil fuels are projected over the next 30 years.

Figure 14.51 **North Macedonia: Gross Electricity generation by energy form**



Projected final consumptions in North Macedonia show a significant increase over the periods, up to 2.8 Mtoe in 2040. In particular, electricity is projected to increase from 0.57 Mtoe in 2020 to almost 0.9 Mtoe in 2040, coal from 0.2 Mtoe to 0.4 Mtoe, and natural gas is projected to be supplied to final consumers starting from 2025 (up to 0.14 Mtoe in 2040). At sectoral level, increase of consumption is expected in particular in industry and transport, with slow/limited growth rate in the residential and tertiary sectors.

The share of RES in gross final consumption is projected to grow from around 26% in 2020 to above 34% in 2040 (corresponding to around 0.7 Mtoe), mainly due to the changes in the electricity generation mix.

Figure 14.52 **North Macedonia: Final Energy Consumption by energy form**

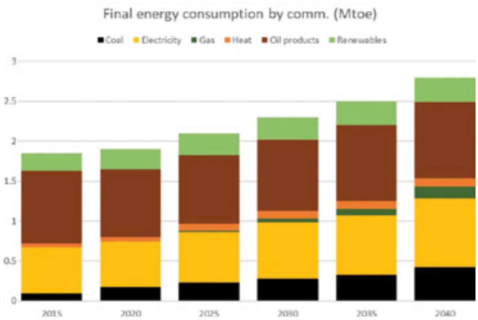
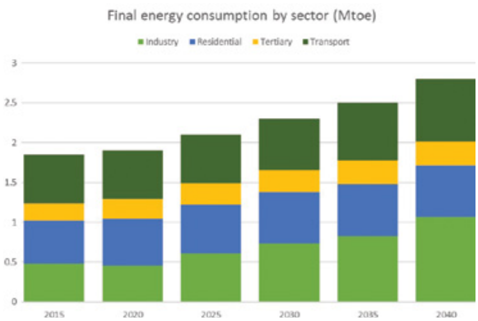


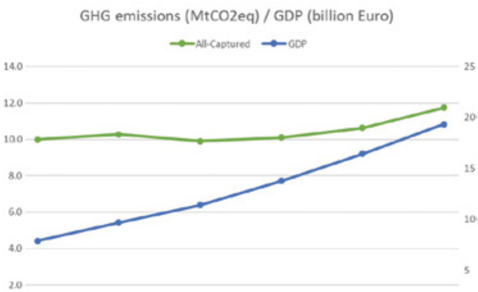
Figure 14.53 **North Macedonia: Final Energy Consumption by Sector**



North Macedonia projects a stabilization of GHG emissions (excluding LULUCF) by 2030 (with respect to the values in 2020) and an increasing trend from 2030 to 2040 caused by higher demand of energy and limited fuel substitution (coal consumption is projected to constantly grow). Given the exogenous GDP values, and the projected GHG emission and GIC[21], the emission intensity of the economy (over GDP) reduces from above 1000 to around 610 (tons CO_2eq / MEuro), but the carbon intensity (over GIC) is projected to remain constant in the range of 3.4 – 3.7 (tons CO_2eq/ toe GIC) over the analysed periods.

[20] Electricity generation from coal and natural gas are not explicitly reported in the NECP, and are derived for this outlook (authors' elaborations) from a consistency check of the energy balance.
[21] Under such a "with existing measure" storyline.

Figure 14.54 **North Macedonia: GHG emissions and GDP projections**



In the National Energy Climate Plan, North Macedonia reports few high level results of an "additional/planned" measure scenario (WAM). Compared to the "existing measures" scenario, there is a 65% net-emissions reduction in 2030 in the WAM scenario. The difference between the two projections are mainly in the energy sector (having in mind that the measures in the AFOLU and Waste sectors are the same in both scenarios), in electricity and heat production (further penetration of RES and decommissioning of Bitola coal-fired power plant which is currently the primary source of electricity in the country).

Romania

Highlights

- Quantitative information are reported until 2035 only. Making use of simple assumptions (trend analysis, correlatation with population, balance consistency check), figures have been stretched until 2040.
- Projection shows a limited increase in renewable energy in the next 20 years.
- Additional measures are "not" expected to change the GHG emissions evolution.

Key data sources

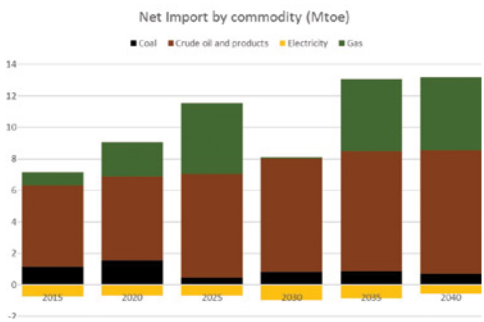
WEM Scenario, Integrated National Energy and Climate Plan (2020) - (Section B - Analytical basis)

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Romania are reported below.

Romania (EU)	2015	2020	2025	2030	2035	2040
Population (million)	19.90	19.30	18.60	18.00	17.40	17.18
GDP (billion Euro)	158.1	180.6	206.3	227.8	245.4	264.4

Net import of energy in Romania is projected to increase (up to 12 Mtoe) in 2035-2040, mainly driven by the increase in natural gas and oil products[22]. Romania is projected to remain a net exporter of electricity over the periods, at around the same level of the base year. The import dependency indicator is projected to increase accordingly, from around 25% in 2020 to 36% in 2040.

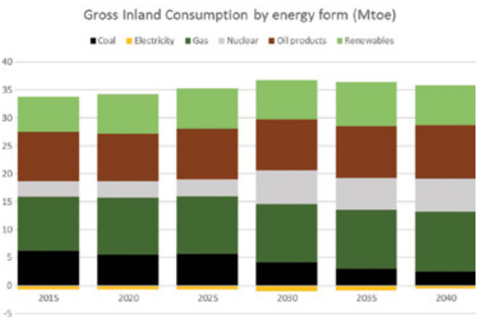
Figure 14.55 **Romania: Net Imports**



Gross Inland Consumption (GIC) in Romania is projected to increase over 35 Mtoe in the periods 2030 - 2040. The mix is projected to slightly change (in particular after 2030) with the increase of nuclear energy (up to 6 Mtoe in 2040) and a corresponding gradual reduction of coal consumption (from 5.5 Mtoe in 2020 to 2.5 Mtoe in 2040). Limited increase in penetration of renewable energy in the mix is expected in the next 20 years. The rate of oil import grows faster than the supply in the system (GIC), thus unveiling a decline in domestic production.

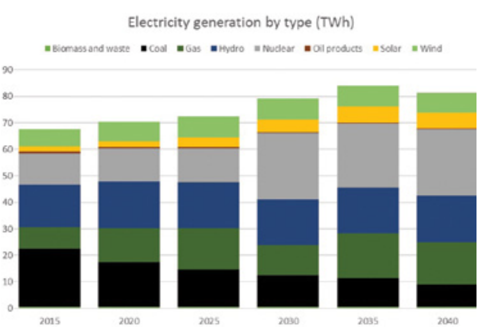
[22] Official submission of Romania reports almost "zero" import of natural gas in 2030. This might be a reporting problem only, or an uncontrolled behaviour of the modelling framework used for the analysis. Since the spotted "issue" regards the primary domestic supply, the complementary item "domestic production" is assumed to balance the supply in the system (and keep consistency over the natural gas chain in the balance). Overall, the analysis is therefore not affected by this issue, apart from the calculation of the import dependency for 2030 (which carries the problem).

Figure 14.56 **Romania: Gross Inland Consumption**



Electricity generation is projected to increase from 70 TWh in 2020 to 81 TWh in 2040. Together with a gradual reduction of coal in electricity generation, the most significant change in the mix is due to the larger contribution of nuclear energy starting from 2030 (producing up to 25 TWh, twice the 2020 production). Among the renewable energy, solar generation is projected to increase from 2.2 TWh to above 6 TWh over the analysed periods while wind, hydro, and biomass are projected to maintain a constant generation level as in the base year[23].

Figure 14.57 **Romania: Gross Electricity generation**



Projected final consumptions in Romania show a very slight increase over the periods, up to 25 Mtoe in 2040. In particular, electricity is projected to increase from 4 Mtoe in 2020 to almost 5 Mtoe in 2040, oil products from 6.8 Mtoe to 7.4 Mtoe, and district heating from 1.2 Mtoe to above 1.4 Mtoe over the same time span. Conversely, a gradual and slow reduction of coal consumption is expected after 2025 (0.5 Mtoe in 2040). At sectoral level, increase of consumption are expected for the residential and transportation[24] sector and quite constant dynamics for the industry and the tertiary. The share of RES in gross final consumption is projected to be quite stable at the level of 25% - 26% (corresponding to around 6 Mtoe).

Figure 14.58 **Romania: Final Energy Consumption**

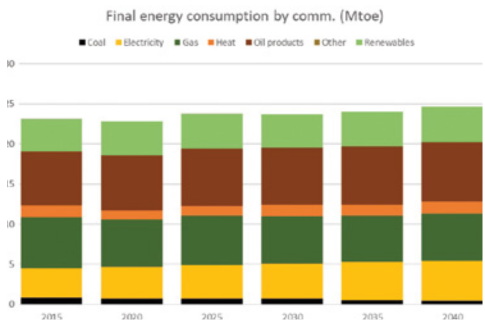
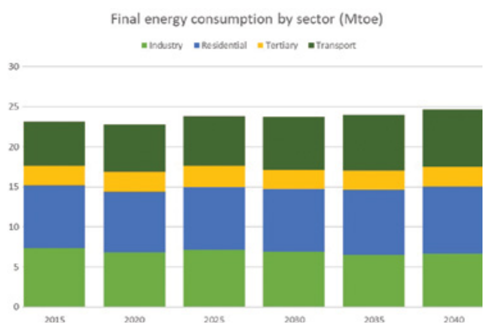


Figure 14.59 **Romania: Final Energy Consumption**



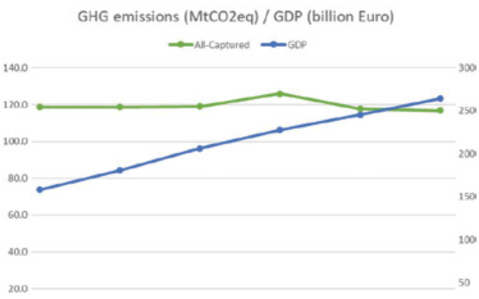
Romania projects a slight "increase" of GHG emissions (excluding LULUCF) over the period 2020-2030 under the existing measure scenario[25], mainly due to the non-ETS sectors.

After 2030, emissions are calculated on the basis of the evolution of the energy variables only (GIC) and show a slow trend of reduction (mainly driven by the reduction of coal use). Eventually, the GHG emissions are projected to remain quite constant at the level of 2020. Given the exogenous GDP values, and the projected GHG emission and GIC, the emission intensity of the economy (over GDP) reduces from around 700 to around 440 (tons CO_2eq / MEuro) in 2040, and the carbon intensity (over

[23] Again, here is still visible the "minor" issue about natural gas in 2030 already mentioned above.
[24] Even in the case of Romania, the most sensitive sector to the (exogenously determined) GDP growth rate is the transportation sector.
[25] In the official submission, GHG emissions are reported until 2030 only.

GIC) from 3.6 to 3.3 (tons CO_2eq/ toe GIC), over the analysed periods.

Figure 14.60 **Romania: GHG emissions and GDP projections**



In the National Energy Climate Plan, Romania reports few high level results of an "additional/ planned" measure scenario (WAM), based on which energy (and electricity) consumptions are even greater than in the "exiting measure scenario" (as a consequence of a different assumption about the "responsiveness" of the economic sectors such as industry and transport to the expected economic growth), thus limiting the space for extra reduction of GHG emissions.

Assessment of the final national energy and climate plan of Romania

National contributions	Assessment of the 2030 ambition level
National target/contribution for renewable energy: • Share of energy from renewable sources in gross final consumption of energy (%)	Unambitious
National contribution for energy efficiency: • Primary energy consumption • Final energy consumption	Low Very low

Sources: European Commission, Energy statistics, Energy datasheets: EU countries; European Semester by country; Romania's final national energy and climate plan

Serbia

Highlights

- GIC anf FEC increase moderately. Contribution per comodity type does not change drastically.
- Power sector is still dominated by domestic lignite and hydro.
- Import dependency increases and emissions intensity decreases as a result of decoupling.

Key data sources

Baseline Scenario, Energy sector development strategy of the Republic of Serbia 2025-2030 (2016).

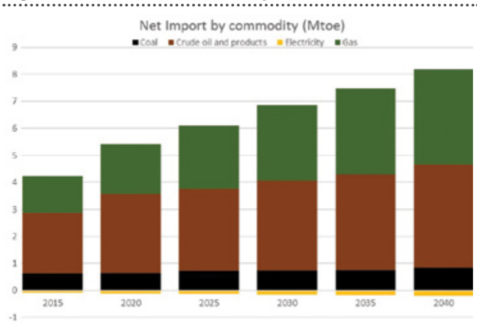
Own elaborations of the baseline scenario projected to 2040.

The projected evolution of the main exogenous factors influencing the energy system and GHG emissions developments of Serbia are reported below.

Serbia (WB6)	2015	2020	2025	2030	2035	2040
Population (million)	7.1	7.0	6.9	6.8	6.8	6.8
GDP (billion Euro)	30.3	35.1	42.9	51.1	61.9	69.4

As the domestic resources of oil and gas in Serbia are depleted it is expected that the growing demand will be covered by a growing level of imports (Figure 14.61). The largest part of net imports will continue to be covered by crude oil and oil products, but natural gas imports is projected to increase considerably in the time horizon to 2040. Energy import dependency is therefore increased from a level close to 30% in 2015 to the level of 44% in 2040.

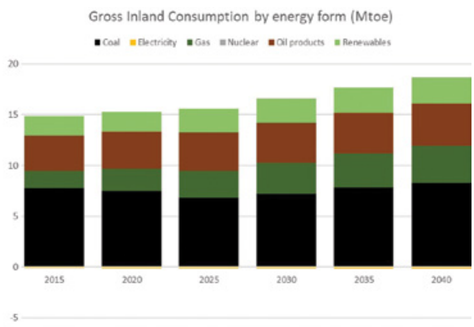
Figure 14.61 **Serbia: Net Imports**



14

The projections of the energy sector scenarios for Serbia are driven by the projected population decline on one hand and the expected GDP growth on the other, as can be seen in the table above. Gross Inland Consumption in the Baseline scenario is projected to increase modestly, reaching 18.5Mtoe in 2040 from 14.8Mtoe in 2015 (an increase of almost 25%). The share of coal (which is mainly domestic lignite) in the GIC is reduced (from around 50% today to 45% in 2040) and natural gas is seen to take up this space (covering 20% of GIC in 2040).

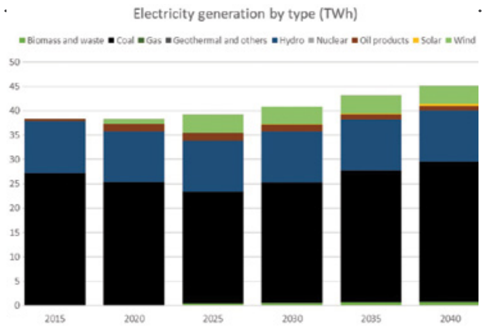
Figure 14.62 **Serbia: Gross Inland Consumption**



Electricity generation is projected to increase by 18% from 2015 to 2040, at the level of 45TWh. As can be seen in Figure 14,63, domestic lignite still dominates the electricity generation until 2040, reaching 28TWh in 2040 from 27TWh in 2015, but its relative contribution decreases from 71% to 64% in the same period. Hydro continues to play an important role, but the generation remains relatively constant at 10TWh, since most of the available potential has already been exploited.

The relative contribution of hydro reduces from 28% in 2015 to 23% in 2040. The noticeable change in the electricity generation comes from the introduction of other renewable energy from 2025 onwards, which is dominated by wind energy producing 3.7TWh in 2040. Solar energy contribution is rather small, while bioenergy is also used to produce a modest amount of electricity in 2040. Electricity generation from RES (wind, solar, bioenergy and hydro) increases modestly to 34% of total generation in 2040 from 28% in 2015.

Figure 14.63 **Serbia: Gross Electricity generation**



The final energy consumption reaches 11.2Mtoe in 2040 (an increase of almost 40% from the level in 2015). The largest increase is seen in the industrial sector, whose activity and corresponding consumption is expected to increase considerably (almost doubled between 2015 and 2040), reaching 3.8Mtoe in 2040. The services sector shows the second largest increase rate in the period considered, reaching 1.3Mtoe by 2040. The share of the residential sector in the FEC is reduced by 2040, although there is a small absolute increase to the level of 3Mtoe, which is a direct effect of the expected population decline in the country. Consumption in transportation increases from 1.9Mtoe in 2015 to 2.9Mtoe in 2040 (increase by 45%) but the relative share in the total FEC remains at a level close to 25%.

Looking at the different energy commodities consumed at the final energy consumption level (Figure 14.64), renewable energy consumption remains at almost the same level of 1Mtoe over the whole time-horizon (since this is mainly biomass utilised in more efficient equipment). District heating exhibits a similar stable level of around 0.8Mtoe while the use of natural gas appears to increase almost three-fold from 2015 to 2040 reaching a value of 2.2Mtoe. There is an increase of 27% for the consumption of electricity from 2015 to 2040, which reaches 34TWh, and covers almost 26% of the FEC in 2040. Oil products continue to cover about one third of the total FEC in 2040 with 3.3Mtoe, the majority of which is consumed in transportation.

The overall share of RES in the gross final energy consumption remains at almost the same level of 21% in the period until 2040, with a large increase of the share of RES in transport which is projected to reach 7% in 2040 and the share of RES in heating/cooling remaining at a level close to 20%.

Figure 14.64 **Serbia: Final Energy Consumption**

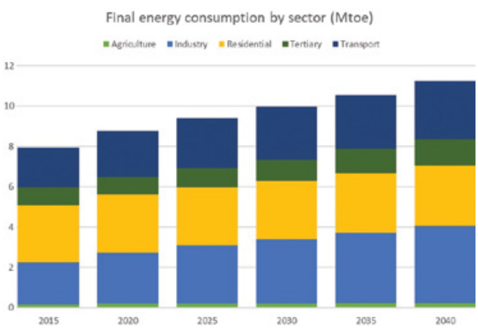
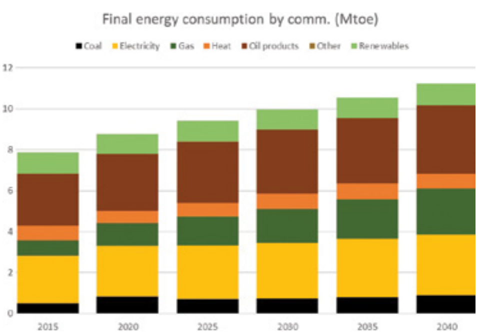
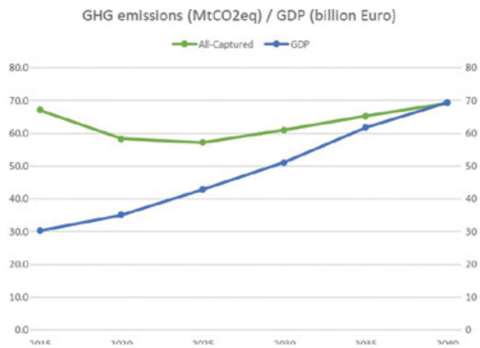


Figure 14.65 **Serbia: Final Energy Consumption b**



The emissions of GHGs are projected to increase from 2020 onwards, associated with the increase of energy consumption and the fact that the overall consumption structure does not change dramatically. However, there is an obvious decoupling between GHG emissions and GDP, and the emissions intensity is reduced considerably from 2215 tCO_2eq/million Euro in 2015 to 998 tCO_2eq/million Euro by 2040. Carbon intensity of the energy use is also changing but not so strongly as the GDP connected intensity, and it is reduced from 4.5 tCO_2eq/toe GIC in 2015 to 3.75 tCO_2eq/toe GIC in 2040. The main reason for this is the fact that the contribution of domestic lignite continues to be strong in the power sector, the contribution of natural gas is increased, and the contribution of renewable energy is relatively constraint since the hydro potential is almost fully utilised, wind and solar make a modest contribution to the electricity generation and the use of RES in the final energy is limited to biomass (remaining at the same levels as 2020).

Figure 14.66 **Serbia: GHG emissions and GDP projections**



Slovenia

Highlights

- Key factor: installation of gas-fired power plants
- Key force: energy efficiency improvements in the building sector.
- "Additional" measures (again, mainly in the generation side) are projected to (potentially) significantly change the dynamics of GHG emissions.

Key data sources

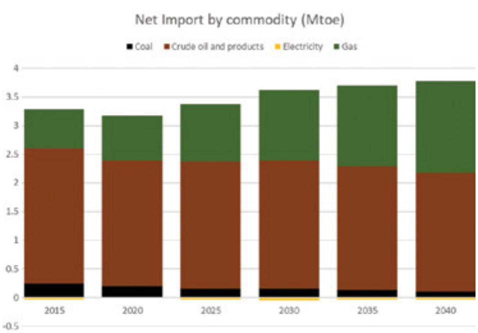
WEM Scenario, Integrated National Energy and Climate Plan (2020) - (Section B - Analytical basis)

The projected evolution of the main exogenous factors influencing energy system and GHG emissions developments of Slovenia are reported below.

Slovenia (EU)	2015	2020	2025	2030	2035	2040
Population (million)	2.069	2.080	2.083	2.089	2.078	2.066
GDP (billion Euro)	40.9	44.5	48.8	52.3	56.0	59.8

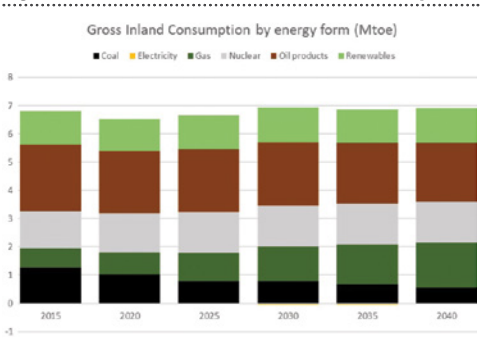
Net import of energy in Slovenia is projected to increase (up to 3.7 Mtoe) in 2040, mainly driven by the increase in natural gas demand (for electricity generation). Slovenia is projected to remain a net exporter of electricity over the periods, at around the same level of the base year. The import dependency indicator is projected to increase accordingly, from 48% in 2015 to 55.4% in 2040. Domestic coal is projected to be extracted and used over all the analysed periods.

Figure 14.67 **Slovenia: Net Imports**



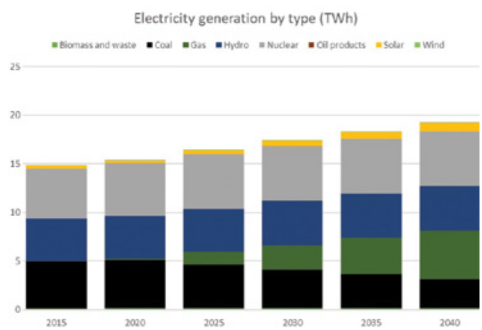
Gross Inland Consumption (GIC) in Slovenia is projected to remain almost constant, always below 7 Mtoe over the periods 2015 - 2040. The mix is projected to change (in particular from 2025) with the increase of natural gas consumption and a corresponding reduction of coal consumption (from 1.2 Mtoe in 2015 to 0.5 Mtoe in 2040). Nuclear energy is projected to remain constant (1.4 Mtoe), while renewable energy forms are projected to increase at a very slow pace (1.15 – 1.25 Mtoe).

Figure 14.68 **Slovenia: Gross Inland Consumption**



Electricity generation is projected to increase from 15 TWh in 2020 to 19.3 TWh in 2040, with the share of electricity generated by gas-powered plants expected to increase from less than 1% in 2020 to around 26% in 2040. Contribution from coal is expected to decline over the periods, but coal is still projected to produce around 3 TWh in 2040. A slow and gradual increase of production of renewable (mainly solar energy) is also expected (around 1 TWh in 2040).

Figure 14.69 **Slovenia: Gross Electricity generation**



Projected final consumptions in Slovenia show a very slight increase over the periods, up to 5.1 Mtoe in 2040. In particular, electricity is projected to increase from 1.1 Mtoe in 2015 to 1.5 Mtoe in 2040. Few changes are expected in the share of consumption by sector: a slight increase is expected in the transportation, thus reflecting the (assumed) sensitivity of the sector to the economic growth, and a slight reduction in the residential/tertiary sectors as a result of higher efficiency of the building-related technologies/ appliances. No relevant structural changes of the economy are assumed/foreseen, leading to slow and smooth dynamics of consumption for industry.

The share of RES in gross final consumption is projected to be quite stable at the level of 22% (0.7 Mtoe).

Figure 14.70 **Slovenia: Final Energy Consumption**

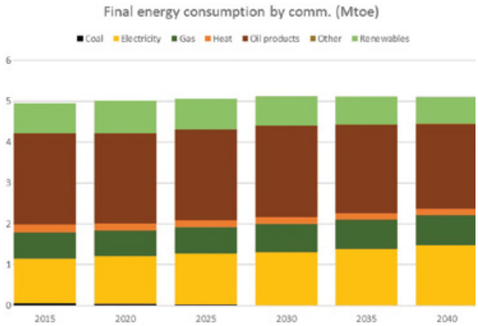
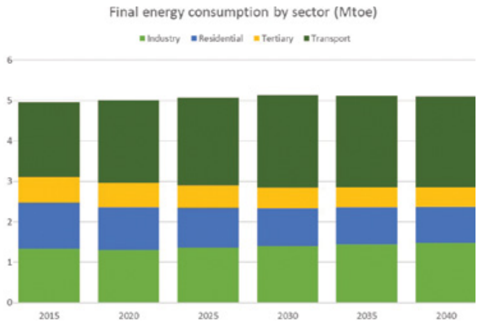
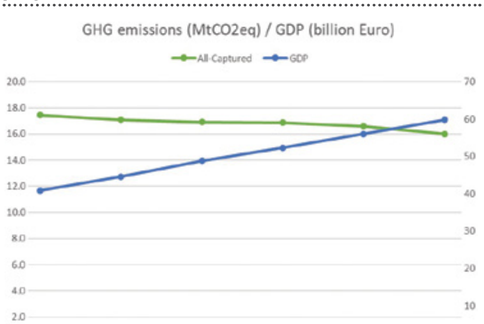


Figure 14.71 **Slovenia: Final Energy Consumption**



Slovenia projects a reduction of GHG emissions (excluding LULUCF) in 2040 by around 10% as compared to emission levels in 2015, mainly driven by the different mix in the electricity generation. Given the exogenous GDP values, and the projected GHG emission and GIC, the emission intensity of the economy (over GDP) reduces from above 425 to around 270 (tons CO_2eq / MEuro), and the carbon intensity (over GIC) from 2.6 to 2.3 (tons CO_2eq/ toe GIC), over the analysed periods.

Figure 14.72 **Slovenia: GHG emissions and GDP projections**



[26] Production from the Krško Nuclear Power Plant

In the National Energy Climate Plan, Slovenia reports the results of an "additional/planned" measure scenario (WAM), based on which significant "extra" emission reductions can be obtained when new nuclear projects[26] are developed (leading to around 13 $MtCO_2$eq in 2030 and 7 $MtCO_2$eq in 2040 against the values of 16.8 and 16 under the "existing measure projection").

Assessment of the final national energy and climate plan of Slovenia

National contributions	Assessment of the 2030 ambition level
National target/contribution for renewable energy: • Share of energy from renewable sources in gross final consumption of energy (%)	 Unambitious
National contribution for energy efficiency: • Primary energy consumption • Final energy consumption	 Modest Very low

Sources: European Commission, Energy statistics, Energy datasheets: EU countries; European Semester by country; Slovenia's final national energy and climate plan

Turkey

Highlights

- Growth of gross inland consumption and considerable growth of electricity demand.
- Penetration of RES in power generation (47% by 2040) and nuclear energy.
- Slight decoupling between economic growth and GHG emissions.

Key data sources

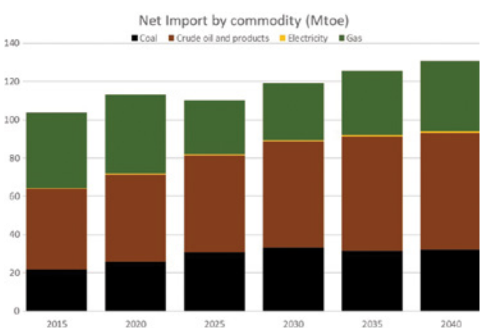
Reference Scenario, Turkey Energy Outlook 2020 (IICEC 2020).

The projected evolution of the main exogenous factors influencing the energy system and GHG emissions developments of Turkey are reported below.

Turkey (peripheral)	2015	2020	2025	2030	2035	2040
Population (million)	76.6	83.9	88.8	93.3	97.2	100.3
GDP (billion Euro)	672.3	800.6	1011.0	1245.1	1446.3	1668.5

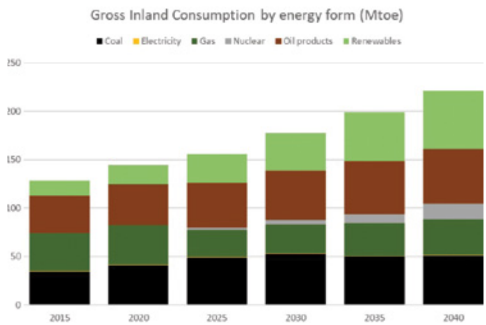
Turkey is projected to experience a strong increase of the population (by almost 20% in twenty years between 2020 and 2040) and in parallel a strong increase in the economy with a doubling of the GDP in the same period. These assumptions affect the projections of energy consumption until 2040. Crude oil and oil products continue to dominate the imports in Turkey (Figure 14.73) covering almost half of net imports and reaching 61Mtoe in 2040. The main use of oil products is in the transportation sector, while the refinery sector in Turkey is reliant around 90% in crude oil imports. Natural gas imports account for the second largest import after oil and oil products, and they are projected to range between 30Mtoe and 36Mtoe in the period until 2040. Hard coal imports are projected to stabilise at a level around 32Mtoe, mainly to be used in the industrial sector and in some of the existing coal fired power plants. Import dependency is projected to decrease to the level of 60% by 2040, from levels above 70% in the recent years.

Figure 14.73 **Turkey: Net Imports**



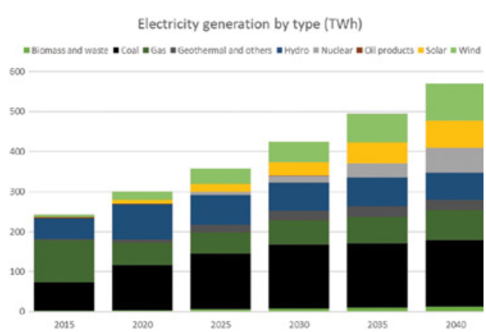
Gross inland consumption is projected to increase by more than 50% between 2020 and 2040. The role of renewable energy is seen to increase notably, reaching 28% of the GIC in 2040, the amount of coal remains at the level of 50Mtoe with its relative contribution being reduced to 23% in 2040 and the contribution of natural gas is decreased to 17% of the GIC. Nuclear energy appears for the first time in the GIC of Turkey after 2025 with the operation of the Akkuyu nuclear power plant and is increasing until 2050, following the nuclear expansion program of the country.

Figure 14.74 **Turkey: Gross inland consumption**



The considerable increase of electricity generation (more than doubled between 2015 and 2040), is supported using domestic coal and lignite, and a significant increase in the generation from renewable energy. In 2040 hydro plants produce 68TWh (12%), wind turbines produce 93TWh (16%), solar plants produce 67.5TWh (12%), geothermal plants 24.4TWh (4%) and bioenergy plants produce 13TWh (2%). In total, renewable energy sources produce 47% of the gross electricity generation in 2040, almost doubling from the 26% contribution in 2015 (mainly hydro plants). The projected installed capacity of solar PV in 2040 reaches 30GW and of wind turbines 23GW. Nuclear electricity generation appears after 2025 and reaches 63TWh by 2040 with the operation of the four units in the Akkuyu power plant and more nuclear power plants according to the country's existing expansion programme, reaching a total installed capacity of 8GW.

Figure 14.75 **Turkey: Gross Electricity generation**



The final energy consumption is projected to increase by 80% from 2015 to 2040, reaching 15.6Mtoe (Figure 14.52). Energy consumption

[28] Production from the Krško Nuclear Power Plant

in industry doubles between 2015 and 2040 to 55Mtoe and is the sector with the largest increase in consumption together with the services sector which reaches 26Mtoe in the same period. Industry consumes more than one third of FEC over the whole period examined. The consumption in the residential sector is increased from 20Mtoe in 2017 to 27Mtoe in 2040, but the relative contribution in FEC decreases from 23% to 18%. The relative share of transportation is slightly decreased to 26% in 2040 (from 28% in 2015) but the amount of energy consumed increases to 41Mtoe. Renewable energy makes a notable contribution to FEC (Figure 14.76) increasing three-fold in the period from 2015 to 2040 reaching a level of 15.6Mtoe. The share of RES including the RES produced electricity in the final energy consumption is expected to reach 22% in 2040 starting from a level of 12% in 2015. Consumption of electricity increases significantly to 491TWh in 2040 from 214TWh in 2015, covering 27% of the FEC. Electrification is one of the strongest trends in the scenarios presented in the Turkish Energy Outlook 2020. Turkey currently has an electricity consumption of 3.7MWh/capita, which is about half of the OECD average, and the strong socio-economic growth envisaged in this scenario leads to a considerable increase to 5.7MWh/capita by 2040.Following the gasification programme of the country, the consumption of natural gas increases to 36.8Mtoe and covers one quarter of FEC, while the share of oil products is slightly reduced to 30% and 47.5Mtoe by 2040. The amount of coal consumed remains almost constant close to 12Mtoe, but its relative contribution reduces to 8% by 2040.

Figure 14.76 **Turkey: Final Energy Consumption**

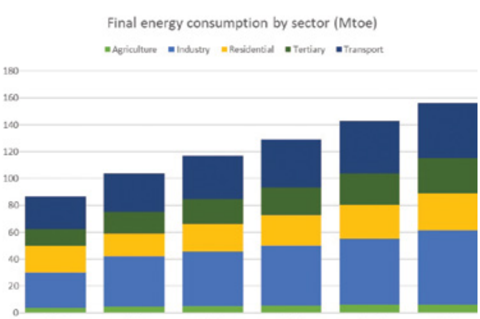
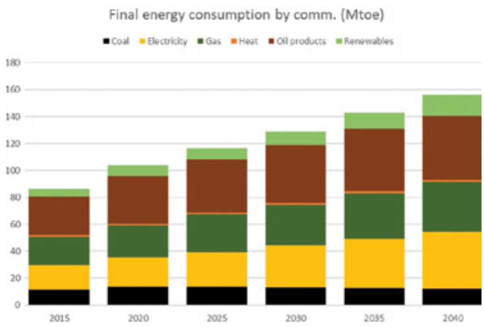
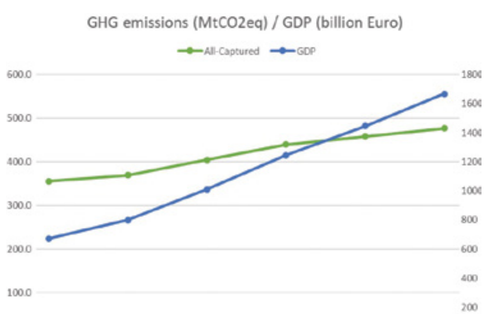


Figure 14.77 **Turkey: Final Energy Consumption**



The scenario projections show a modest increase of energy related GHG emissions from 355Mtons CO_2eq in 2015 to 477Mtons CO_2eq in 2040 (Figure 14.78), while the decoupling between emissions and GDP development is evident in the figure. The emissions intensity reduces from 529 tons CO_2eq/million Euro in 2015 to 286 tons CO_2eq/million Euro by 2040. On the other hand, the carbon intensity expressed as GHG emissions per unit of GIC is reduced at a smaller rate from 2.77 tons CO_2eq/ toe GIC in 2015 to 2.15 tons CO_2eq/ toe GIC by 2040, mainly due to the increase of renewables and the introduction of nuclear energy in the gross inland consumption.

Figure 14.78 **Turkey: GHG emissions and GDP projections**



In the "Turkey Energy Outlook 2020" the results of an "Alternative scenario" are also reported, which assumes additional policy initiatives focusing on energy efficiency, competitiveness, and sustainability of the energy system. In the Alternative scenario a reduction of 12.5% in the final energy consumption compared to the reference scenario is projected by 2040, due

14

to increased energy efficiency measures. The share of renewable energy in the GIC increases to 33% in 2040 (from 28% in the reference scenario) and the contribution of wind and solar in the electricity generation increases to 36% (from 28% in the reference scenario). The effect of these differences on the energy related GHG emissions is a reduction by 30% in 2040 between the two scenarios.

14.2.2 Analysis per group of countries

Looking at the scenario projections for the countries of SE Europe three distinct pathways for the energy sector development of different country groups are evident:

i) EU Member states, whose energy policies are triggered by the overall EU decarbonisation policies show a clear decoupling between economic growth and energy consumption (and related emissions).
ii) Western Balkan countries, which exhibit a growth in energy consumption associated with their projected economic growth.
iii) Turkey, whose population is projected to grow strongly with considerable economic growth. These two factors drive a considerable increase in energy consumption with a slight decoupling between emissions and economic growth. Turkey is by far the largest energy consumer in the region (currently consuming almost the same amount as all the other countries together) and is therefore analysed separately in Section 14.2.1.13.

Since the behaviour of these groups is so different, each group is analysed separately in the following sections.

EU countries

Looking at the projection of the gross inland consumption in the EU member states of the SEE region (Bulgaria, Croatia, Cyprus, Greece, Romania, Slovenia) in Figure 14.80, the overall tendency shows a stabilisation and even a small reduction in the time horizon to 2040. The decrease of the use of coal is evident, reaching a minimum level by 2040 while oil products lose part of their share in the GIC. The winners to this change are renewable energy and nuclear energy. The group remains a net importer in the time horizon until 2040, but the import dependency is reduced between 2020 and 2030 and then stabilised at a level close to 42% until 2040. Crude oil and oil products cover the majority of imports (68% in 2040), imports of coal are reduced significantly, while imports of natural gas remain at a level close to 12Mtoe after 2030.

Figure 14.79 **EU member states in SEE: Net Imports**

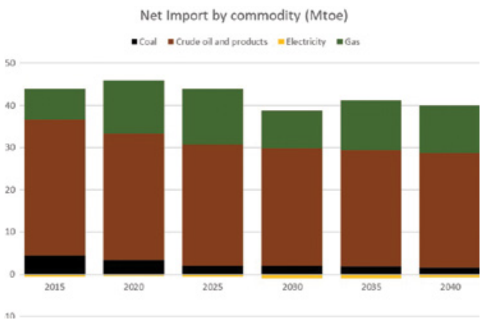


Figure 14.80 **EU member states in SEE: Gross Inland Consumption**

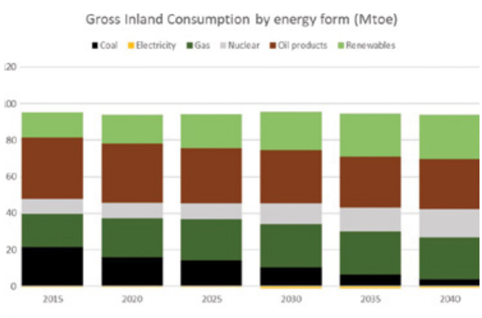
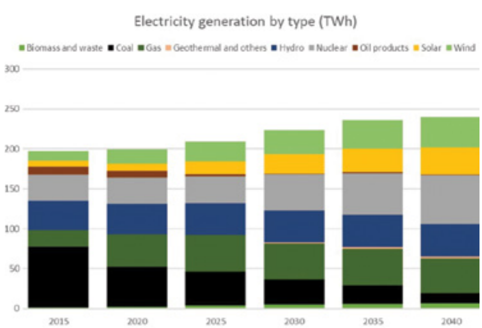


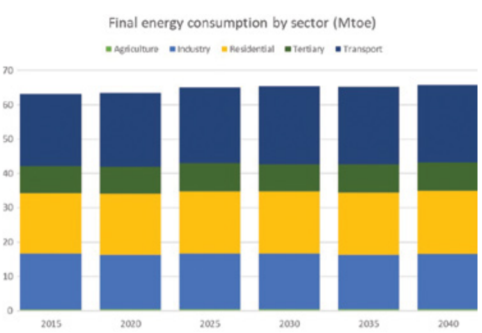
Figure 14.81 **EU member states in SEE: Gross Electricity generation**



The graph of electricity generation presents the largest changes seen in the energy sector of the region (Figure 14.81). First, electricity generation is increasing to feed the increased electrification in the demand sectors, reaching almost 240TWh by 2040. Oil fired power plants are completely phased out, generation from coal fired power plants is reduced considerably and natural gas generation is increasing slightly between 2020 and 2040. Generation from hydro remains relatively stable (since most of the potential in the region is already exploited). The gap is filled by the notable increase of other renewable (81.29TWh) and nuclear (61TWh) electricity generation in 2040. It is interesting to note that by 2040, nuclear energy produces 26% of the gross electricity generated in this group of countries, natural gas fired plants 18%, hydro power 17%, wind energy 16%, solar energy 14%, coal fired plants 5%, biomass fired plants 3% and geothermal plants 1%. This is a considerable change from the situation in 2015, when coal fired power plants dominated the scene with 39% of the gross electricity generation, followed by hydro plants at 19% and nuclear plants at 17% and gas plants at 11%.

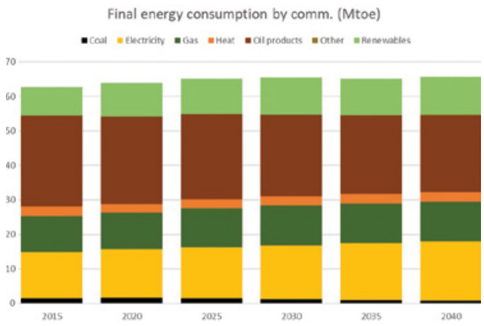
The final energy consumption is stabilised (Figure 14.82) with the relative contribution of the different sectors not changing noticeably over the twenty year of the projections.

Figure 14.82 **EU member states in SEE: Final Energy Consumption**



The contribution of oil products in the final energy consumption decreases and the share is taken up mainly by electricity and renewable energy sources (Figure 14.83).

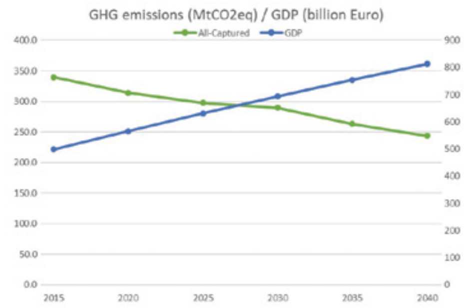
Figure 14.83 **EU member states in SEE: Final Energy Consumption**



It is evident from these results that even in the "With Existing Measures" scenarios of the South Eastern Europe EU member states, the current policies have a significant impact on the energy system and the related GHG emissions. Renewable energy and energy efficiency targets together with the EU-ETS scheme are the overarching obligations and policies which lead to the introduction of RES in the energy system, the stabilisation of FEC and the reduction in GHG emissions. The decoupling between GDP growth and GHG emissions is evident when summing over all the EU member states in the region (Figure 14.84). It is interesting to note that the emissions intensity summing over these countries is more than halved from 681tons CO_2eq/MEuro in 2015 to 300tons CO_2eq/MEuro in 2040.

This is achieved to a large extended by the phase out of coal from the power generation mix, the considerable increase of renewable energy sources in electricity generation and in the final energy consumption and the fact that the final energy consumption remains almost constant until 2040 (despite the projected economic growth) through the introduction of energy efficiency measures. The contribution of nuclear power plants is almost doubled between 2020 and 2040, contributing to the lower emissions from electricity generation. None of the EU member states in the region reports the use of CCS options in their NECPs, which makes it even harder to reach the achieved emissions reduction through investments in technologies with zero or limited emissions.

Figure 14.84 **EU member states in SEE: GHG emissions and GDP projections**



Western Balkan countries

The projection of Gross Inland Consumption in the six Western Balkan countries (WB6: Albania, Bosnia i Herzegovina, Kosovo, Montenegro, North Macedonia and Serbia) in Figure 14.86, presents a rather different story from that of the EU member states in the region. Following the expected growth of GDP (Figure 14.90), GIC is projected to increase by almost 40% between 2015 and 2040, with the amount of coal being held almost constant, close to 15Mtoe. Natural gas is the emerging fuel with a constant gradual increase, connected with the pipeline expansion projects in the Western Balkans region. Crude oil and oil products increase by 45% reaching 12Mtoe in 2040, and renewable energy increases substantially (by 70%) to 8.3Mtoe in 2040, but still covers only 20% of the total GIC of the group of countries. The group remains a net importer of energy and furthermore, import dependency increases to a level of 42% in 2040 (from 33% in 2015). Crude oil and oil products cover the largest part of imports reaching almost 11Mtoe by 2040 and the imports of natural gas are continuously increasing, reaching 5.4Mtoe in 2040.

Figure 14.85 **Western Balkans: Net Imports**

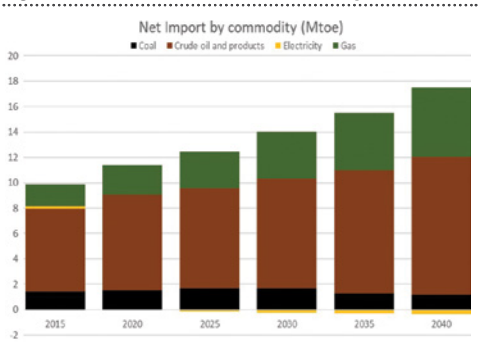
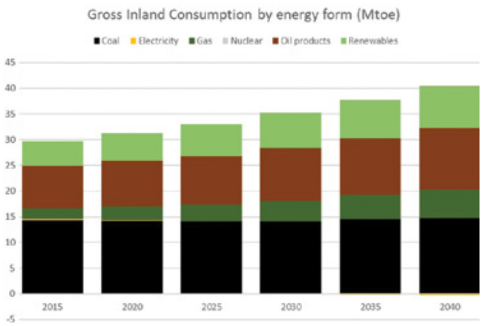
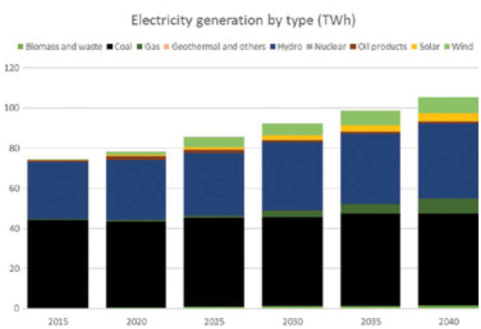


Figure 14.86 **Western Balkans: Gross Inland Consumption**



Electricity generation is still dominated by coal fired power plants which produce 44% of electricity in 2040 (compared to 61% in 2015) and hydro power which produces 36% of electricity in 2040 compared to 39% in 2015. Electricity generation from gas increases after 2025 producing 8% of the generation in 2040.

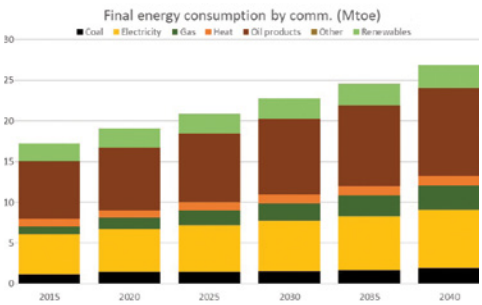
Figure 14.87 **Western Balkans: Gross electricity generation**



The contribution of wind and solar energy after 2020, increases steadily and by 2040 wind produces almost 8TWh and solar almost 4.4TWh. These two renewable energy sources cover 12% and hydro power 36% of the total electricity generation in 2040, so overall 49% of electricity in the Western Balkans is produced by RES (including 1.4% of electricity generation from bioenergy).

At the level of final energy consumption (Figure 14.88) there is an increase of 55% between 2015 and 2040, reaching a level of almost 27Mtoe for the group. Transport is the dominant sector, consuming 30% of the total FEC, followed by residential (28%) and industry (27%), while the services sector is limited to 13%.

Figure 14.88 **Western Balkans: Final Energy Consumption by sector**



Oil products continue to dominate the scene (Figure 14.89) while the use on natural gas in the final energy consumption is increasing steadily over the whole time-horizon to 2040. The growth of electricity is also evident with the total consumption in the group reaching 83TWh in 2040. District heating remains almost constant (around 1.1Mtoe) until 2040, and coal continues to be part of the FEC at a level of 1.8Mtoe in 2040. Renewable energy in FEC, the largest part of which is biomass, increases by 30% from 2015 to 2040 reaching 2.8Mtoe.

Figure 14.89 **Western Balkans: Final Energy Consumption by energy form**

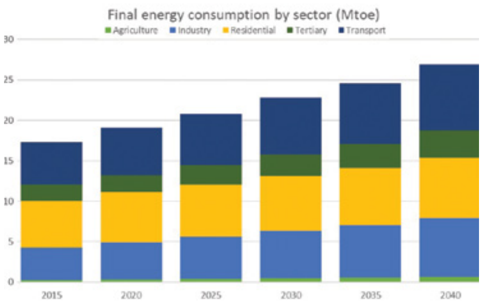
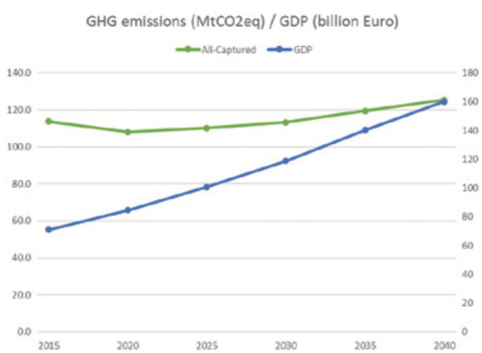


Figure 14.90 **Western Balkans: GHG emissions and GDP projections**



The overall GHG emissions in this group of countries increases from 2020 to 2040 but with a rate much lower than the projected growth of the GDP. The trend however is rather different compared to the trend in the group of EU member states shown in Figure 14.90. The emissions intensity is rather high in 2015 at 1598 tons CO_2eq/ MEuro but it decreases considerably to almost 800 tons CO_2eq/ MEuro in 2040.

14.2.3 Electrification of the Transport Sector in SE Europe

Electrification of transportation and in particular of road transport is a policy dimension which is present, to a greater or lesser extent, in all the scenarios of the NECPs submitted by EU member states. Countries like Bulgaria and Romania also mention the implementation of policies targeting modal shift from road transport to rail transport (which is electrified) as a specific measure for reducing GHG emissions from transport. Moreover, Romania aims to have 700000 Electric Vehicles (EVs) and 600000 charging points by 2030. Greece targets to electrify its rail system and reach a total of 9% of the cars fleet to be Battery Electric Vehicles (BEV) by 2030, assuming that at least 30% of the new registrations from 2027 onwards will be BEVs. Cyprus targets for BEVs to be between 7% and 12% of its car fleet by 2030. The scenarios for Croatia foresee that EVs and hybrid vehicles cover 3.5% of passenger activity by 2030.

The Western Balkan countries mention electromobility in their strategies but most of them do not go into detailed quantified analysis. North Macedonia however, in the recently published Strategy for the Energy Development to 2040, explicitly mentions that the penetration of BEVs by 2030 is projected to be 10% of the car fleet in the reference scenario, 40% of the fleet in the "moderate" scenario and 45% in the "green" scenario. It is expected that as the WB countries start developing their NECPs, electromobility will be quantified and its effects will be included in detail in the scenarios.

Turkey has a strong rail electrification program and in the alternative scenario of the "Turkey Energy Outlook", electricity consumption in transport is projected to reach 16TWh by 2040, one third of which is expected to be consumed by road vehicles. The increase in the uptake of EVs is expected to start from the middle of the current decade, to reach the target of 1 million EVs by 2030. Furthermore, Turkey's Automobile Initiative Group (TOGG) is planning to produce BEVs in the country, which is expected to be a game changer in the introduction of BEVs.

The trend in the price reductions of EVs, the tax breaks and other support schemes are expected to improve their financial attractiveness, however the deployment of charging points is a barrier which must be eliminated first, before large scale introduction of EVs is achievable.

14.3 Discussion

Although the energy sectors of SEE countries exhibit different characteristics, depending on the group in which they belong (EU MS, WB6, Turkey) there is one common trend in all of them: the use of renewable energy sources is projected to steadily increase until 2040. The sector in which RES has the highest contribution is electricity generation. The power sector of EU member states in the region is projected to be radically transformed (even in the WEM scenario) with RES and nuclear dominating the scene, almost completely displacing coal. In the power sectors of the six Western Balkan countries, RES is increased by the addition of wind and solar to the traditionally exploited hydro power. Finally, Turkey is covering part of its rapidly increasing electricity demand through a substantial exploitation of the wind, solar and geothermal potential.

The projected final energy consumption trend is the most striking difference between the thirteen countries. FEC in each one of the EU member states stabilises after 2025 despite the projected economic growth, while in the Western Balkan countries it is projected to increase considerably until 2040. The projected strong economic growth and the population growth of Turkey is translated in almost doubling its FEC from 2015 to 2040. Natural gas is projected to play an increased role in the region, penetrating the power sector and the demand sectors.

All countries in the region continue to be net importers, with the notable exception of Cyprus, whose natural gas exports after 2025, turns it into a net exporter.

The increasing use of RES and natural gas, together with the introduction of energy efficiency measures and electrification of the demand, leads to a considerable decoupling of economic growth from GHG emissions in the EU Member States of the region. In the Western Balkan countries, there appears to be a stabilisation of the total GHG emissions, which leads to a decoupling from the relatively strong GDP growth projected in the scenarios. Turkey appears to continue on an increasing emissions path, although at a lower rate compared to the historical data.

In most of the sources which were used in this analysis, at least one more ambitious scenario was presented, mainly with more aggressive RES penetration, and relatively higher energy efficiency trends. This is driven by the strong environmental policies of the EU which are gradually being transferred to the other countries in the region through the Energy Community obligations. Furthermore, the considerable reduction of renewable energy technology costs has contributed strongly to their penetration in the power system.

Albania

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	90	105	127	167	194	234
	Crude oil and products	949	1149	1397	1780	2549	3266
	Gas	41	63	84	116	134	159
	Electricity	169	135	77	121	126	126
Gross Inland Consumption (ktoe)	Coal	90	105	127	167	194	234
	Oil products	1448	1815	2104	2756	3256	3932
	Gas	41	63	84	116	134	159
	Nuclear	0	0	0	0	0	0
	Electricity	169	135	77	132	100	77
	Renewables	856	1131	1363	1625	1920	2318
Gross Electricity Generation by source (GWh)	Coal						
	Oil products						
	Gas			314	500	500	500
	Nuclear						
	Biomass and waste						
	Hydro	7349	9093	9184	9368	10304	12365
	Wind	0	0	120	240	264	290
	Solar	162	282	340	422	464	510
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal	92	107	130	157	184	220
	Oil products	1248	1543	1954	2657	3104	3723
	Gas	39	61	81	102	120	144
	Electricity	537	621	702	798	932	1118
	Heat	0	0	0	0	0	0
	Renewables	258	396	442	511	598	717
	Other	0	0	0	0	0	0
Final Energy Consumption per Sector (ktoe)	Industry	361	444	540	674	805	959
	Residential	594	824	944	1131	1283	1490
	Tertiary	196	248	348	519	696	930
	Transport	907	1076	1292	1629	1806	2098
	Agriculture	118	137	186	272	348	445
GHG Emissions	ktons of CO_2eq	5976	7357	8464	8982	9973	11044
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	2.29	2.26	2.25	1.87	1.78	1.64
	Emission intensity (tons CO_2eq/ MEuro)	610	598	584	528	504	480
	Import Dependency	48%	45%	45%	46%	54%	56%
	Share of RES in FEC	37%	37%	34%	30%	30%	30%

Bosnia i Herzegovina

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	639	639	639	639	639	639
	Crude oil and products	1477	1592	1622	1591	1614	1693
	Gas	190	216	243	372	398	508
	Electricity	-187	-196	-230	-242	-254	-266
Gross Inland Consumption (ktoe)	Coal	3658	3724	4168	3820	3784	3753
	Oil products	1477	1592	1622	1591	1614	1693
	Gas	190	216	243	372	398	508
	Nuclear	0	0	0	0	0	0
	Electricity	-187	-196	-230	-242	-254	-266
	Renewables	980	1017	1133	1273	1402	1430
Gross Electricity Generation by source (GWh)	Coal	9000	9600	11571	10375	10375	10375
	Oil products	300	200	0	0	0	0
	Gas	0	0	0	1196	1196	2072
	Nuclear	0	0	0	0	0	0
	Biomass and waste	0	300	300	300	300	300
	Hydro	6000	5700	6523	6523	6523	6523
	Wind	0	253	446	1099	1752	1835
	Solar	0	0	0	329	657	688
	Geothermal and others	0	0	0	0	0	0
Final Energy Consumption per energy form (ktoe)	Coal	300	268	229	229	219	210
	Oil products	1400	1520	1565	1536	1558	1634
	Gas	190	216	243	269	295	330
	Electricity	960	980	1182	1244	1305	1367
	Heat	200	206	202	221	226	233
	Renewables	200	206	202	221	230	241
	Other						
Final Energy Consumption per Sector (ktoe)	Industry	750	781	816	834	851	888
	Residential	1000	1042	1088	1112	1134	1184
	Tertiary	400	417	435	445	454	474
	Transport	1100	1155	1284	1328	1395	1470
	Agriculture						
GHG Emissions	ktons of CO_2eq	19786	20473	22414	21222	21212	21591
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.23	3.22	3.23	3.11	3.05	3.03
	Emission intensity (tons CO_2eq/ MEuro)	1353.5	1196.4	1135.4	931.8	827.3	747.9
	Import Dependency	34.6%	35.4%	32.8%	34.6%	34.5%	36.2%
	Share of RES in FEC	17.7%	17.3%	18.2%	19.9%	21.1%	20.6%

Bulgaria

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	1928	820	761	644	561	468
	Crude oil and products	3820	4454	4399	4188	3966	3842
	Gas	1993	2613	2617	3131	3116	2799
	Electricity	-909	-687	-688	-688	-688	-688
Gross Inland Consumption (ktoe)	Coal	6638	6420	6315	4809	2698	753
	Oil products	4355	4341	4271	4049	3822	3687
	Gas	2572	2740	2765	3391	3378	3052
	Nuclear	3912	4019	4019	4019	5951	7883
	Electricity	-909	-687	-688	-688	-688	-688
	Renewables	2022	2309	2555	2787	2775	2989
Gross Electricity Generation by source (GWh)	Coal	20215	19426	18579	14528	7512	1172
	Oil products	440					
	Gas	1732	1885	2295	5539	6986	4897
	Nuclear	15662	14926	14926	14926	22676	30426
	Biomass and waste	54	280	1345	1377	1385	1395
	Hydro	4061	4619	4619	4619	4619	4619
	Wind	1144	1451	1564	1901	1901	3608
	Solar	1129	1402	2653	4841	4841	4841
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal	332	360	333	292	236	135
	Oil products	3378	3478	3581	3483	3288	3158
	Gas	1300	1356	1319	1346	1303	1323
	Electricity	2437	2612	2794	2960	3145	3255
	Heat	818	819	863	868	846	845
	Renewables	1238	1368	1441	1454	1453	1514
	Other						
Final Energy Consumption per Sector (ktoe)	Industry	2715	2841	2932	2983	2959	2966
	Residential	1197	1213	1282	1262	1266	1273
	Tertiary	2195	2312	2363	2408	2430	2490
	Transport	3394	3626	3753	3748	3614	3499
	Agriculture						
GHG Emissions	ktons of CO_2eq	64251	63601	62639	56989	43839	31007
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.46	3.32	3.26	3.10	2.44	1.75
	Emission intensity (tons CO_2eq/ MEuro)	1290	1080	922	736	511	335
	Import Dependency	37%	38%	37%	40%	39%	36%
	Share of RES in FEC	17%	18%	20%	22%	22%	24%

Croatia

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	751	585	419	253	150	47
	Crude oil and products	2955	2426	1818	1590	1715	1997
	Gas	713	1714	1807	1986	1783	2084
	Electricity	514	454	394	335	233	131
Gross Inland Consumption (ktoe)	Coal	751	585	419	253	150	47
	Oil products	3414	3092	2769	2447	2572	2696
	Gas	2144	2497	2850	3203	3000	2798
	Nuclear						
	Electricity	514	454	394	335	233	131
	Renewables	1195	1775	2356	2936	3103	3270
Gross Electricity Generation by source (GWh)	Coal	2671	673	673	673	673	
	Oil products	77	77	77			
	Gas	2232	2568	2904	2347	2217	2888
	Nuclear						
	Biomass and waste	98	508	1089	1670	1670	1670
	Hydro	6199	6585	6806	7027	7206	7386
	Wind	650	1722	2375	3027	3666	4306
	Solar	68	134	402	671	1134	1648
	Geothermal and others		70	136	197	363	363
Final Energy Consumption per energy form (ktoe)	Coal	139	420	254	88	0	0
	Oil products	2755	2574	2321	2068	2164	2260
	Gas	1170	1369	1568	1927	1802	1532
	Electricity	1317	1291	1396	1429	1439	1450
	Heat	226	230	230	230	230	230
	Renewables	582	843	1103	1367	1280	1332
	Other	1	1	1	1	1	1
Final Energy Consumption per Sector (ktoe)	Industry	1394	1541	1601	1660	1635	1610
	Residential	1784	1974	2049	2125	2093	2061
	Tertiary	934	1033	1073	1112	1096	1079
	Transport	2078	2180	2197	2213	2134	2055
	Agriculture						
GHG Emissions	ktons of CO_2eq	25371	23500	23000	22500	21000	20000
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.16	2.80	2.62	2.45	2.32	2.24
	Emission intensity (tons CO_2eq/ MEuro)	521	401	363	330	283	248
	Import Dependency	62%	62%	50%	45%	43%	48%
	Share of RES in FEC	22%	27%	31%	35%	36%	38%

Cyprus

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal						
	Crude oil and products	1995	1906	968	960	882	816
	Gas			-1416	-2326	-3344	-4079
	Electricity						
Gross Inland Consumption (ktoe)	Coal						
	Oil products	1995	1906	968	960	882	816
	Gas			827	912	594	397
	Nuclear						
	Electricity						
	Renewables	162	254	304	347	591	777
Gross Electricity Generation by source (GWh)	Coal						
	Oil products	4086	4400	0	20	20	20
	Gas			4500	5000	3300	2000
	Nuclear						
	Biomass and waste	45	59	106	150	150	180
	Hydro						
	Wind	248	248	248	248	248	248
	Solar	195	600	1100	1400	3950	6000
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal						
	Oil products	938	974	965	941	878	816
	Gas						
	Electricity	352	452	502	574	631	679
	Heat	1	0				
	Renewables	108	126	132	151	177	209
	Other						
Final Energy Consumption per Sector (ktoe)	Industry	210	234	242	252	255	257
	Residential	317	344	354	369	374	378
	Tertiary	207	234	242	252	255	257
	Transport	622	691	712	742	751	759
	Agriculture	43	48	50	52	52	53
GHG Emissions	ktons of CO_2eq	8321	9146	7535	7190	6649	5761
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.86	4.23	3.59	3.24	3.22	2.89
	Emission intensity (tons CO_2eq/ MEuro)	505	420	306	265	222	174
	Import Dependency	92%	88%	-21%	-62%	-119%	-164%
	Share of RES in FEC	10%	13%	16%	18%	32%	43%

14

North Macedonia

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	84	168	224	285	320	414
	Crude oil and products	966	882	784	825	896	936
	Gas	140	210	224	270	304	342
	Electricity	210	140	168	120	80	108
Gross Inland Consumption (ktoe)	Coal	965	945	924	960	960	1085
	Oil products	965	891	840	870	960	1015
	Gas	161	225	248	300	316	335
	Nuclear						
	Electricity	188	180	200	150	100	120
	Renewables	402	459	588	720	864	945
Gross Electricity Generation by source (GWh)	Coal	2536	2250	2015	1989	1846	1933
	Oil products						
	Gas	561	785	792	886	841	680
	Nuclear						
	Biomass and waste	0	70	174	233	279	326
	Hydro	2117	1803	2163	3838	4187	4355
	Wind	186	221	349	582	1047	1547
	Solar	23	233	802	1163	1465	1913
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal	93	171	231	276	325	420
	Oil products	907	855	861	897	950	952
	Gas	0	0	21	46	75	140
	Electricity	574	570	630	713	750	868
	Heat	56	57	84	92	100	112
	Renewables	222	247	273	276	300	308
	Other						
Final Energy Consumption per Sector (ktoe)	Industry	481	456	609	736	825	1064
	Residential	537	589	609	644	650	644
	Tertiary	222	247	273	276	300	308
	Transport	611	608	609	644	725	784
	Agriculture						
GHG Emissions	ktons of CO_2eq	10000	10280	9900	10100	10640	11750
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.73	3.81	3.54	3.37	3.33	3.36
	Emission intensity (tons CO_2eq/ MEuro)	1266	1060	868	733	647	607
	mport Dependency	52%	52%	50%	50%	50%	51%
	Share of RES in FEC	25%	26%	30%	33%	34%	34%

Greece

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	335	158	137	152	179	186
	Crude oil and products	15950	13774	12742	11612	11125	10647
	Gas	2979	5230	4784	4800	4238	4230
	Electricity	600	533	425	394	411	429
Gross Inland Consumption (ktoe)	Coal	6765	2339	1097	153	181	188
	Oil products	12997	12124	11039	9912	9292	8667
	Gas	2979	5250	4832	4864	4302	4294
	Nuclear						
	Electricity	600	533	425	394	411	429
	Renewables	2714	3608	4966	6868	7956	8942
Gross Electricity Generation by source (GWh)	Coal	26751	8118	4536			
	Oil products	4847	3594	2210	826	768	668
	Gas	8817	22958	19169	18304	13536	12666
	Nuclear						
	Biomass and waste	195	425	772	1575	2137	2479
	Hydro	5880	5453	6528	6597	6690	6785
	Wind	3834	7280	12610	17208	22561	23245
	Solar	3757	4548	8202	11816	12505	14277
	Geothermal and others				631	1301	1971
Final Energy Consumption per energy form (ktoe)	Coal	208	160	139	153	181	188
	Oil products	10307	9287	8551	7750	7190	6624
	Gas	1018	1244	1597	1759	1933	2091
	Electricity	4397	4612	4680	4852	5143	5383
	Heat	44	43	41	39	37	35
	Renewables	1510	2398	2492	2831	2695	2887
	Other	2	0	0	0	0	0
Final Energy Consumption per Sector (ktoe)	Industry	3224	3011	2943	2879	2930	2968
	Residential	4351	4691	4480	4465	4293	4253
	Tertiary	2426	2177	2331	2451	2576	2643
	Transport	7484	6997	7163	7066	6887	6815
	Agriculture	450	459	487	523	523	529
GHG Emissions	ktons of CO_2eq	105733	82000	68710	59900	57030	53995
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	4.06	3.44	3.07	2.70	2.58	2.40
	Emission intensity (tons CO_2eq/ MEuro)	572	409	313	249	217	191
	mport Dependency	76%	83%	81%	76%	72%	69%
	Share of RES in FEC	15%	22%	28%	35%	38%	41%

Kosovo

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	-13	3	8	24	-497	-862
	Crude oil and products	578	647	684	703	740	786
	Gas	0	0	1	52	340	704
	Electricity	73	40	0	-40	-50	-50
Gross Inland Consumption (ktoe)	Coal	1584	1668	1777	1926	1786	1344
	Oil products	578	647	684	703	740	786
	Gas	0	0	1	52	340	704
	Nuclear	0	0	0	0	0	0
	Electricity	73	73	0	0	0	0
	Renewables	291	347	394	393	399	465
Gross Electricity Generation by source (GWh)	Coal	4778	5000	6770	7371	6765	4897
	Oil products	5	3	4	1	0	8
	Gas	0	0	0		1251	2961
	Nuclear	0	0	0	0	0	0
	Biomass and waste	14	35	77	43	53	61
	Hydro	130	495	463	699	696	720
	Wind	2	105	263	154	185	276
	Solar	0	35	131	209	249	719
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal	90	105	114	115	124	141
	Oil products	578	647	684	703	740	786
	Gas	0	0	1	52	101	138
	Electricity	386	381	436	482	523	548
	Heat	6	37	47	48	48	47
	Renewables	273	275	282	280	275	287
	Other	0					
Final Energy Consumption per Sector (ktoe)	Industry	296	329	367	411	450	507
	Residential	457	474	520	558	597	626
	Tertiary	204	233	238	243	260	268
	Transport	376	409	439	468	503	547
	Agriculture						
GHG Emissions	ktons of CO_2eq	8600	9184	9769	10586	10826	10008
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.40	3.36	3.42	3.44	3.32	3.03
	Emission intensity (tons CO_2eq/ MEuro)	1686	1435	1269	1151	993	770
	Import Dependency	25%	25%	24%	24%	16%	18%
	Share of RES in FEC	21%	22%	21%	20%	19%	20%

Montenegro

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	-14	-19	-21	-134	-118	-105
	Crude oil and products	329	346	356	372	387	407
	Gas	0	0	1	132	147	175
	Electricity	-9	-14	-18	-23	-28	-33
Gross Inland Consumption (ktoe)	Coal	288	317	334	3	3	2
	Oil products	329	346	356	372	387	407
	Gas	0	0	1	132	147	175
	Nuclear	0	0	0	0	0	0
	Electricity	-9	-14	-18	-23	-28	-33
	Renewables	399	454	484	490	518	540
Gross Electricity Generation by source (GWh)	Coal	807	897	899	0	0	0
	Oil products	0	0	0	0	0	0
	Gas	0	0	0	892	940	1101
	Nuclear	0	0	0	0	0	0
	Biomass and waste	0	0	12	12	12	12
	Hydro	2078	2478	2556	2859	3005	3108
	Wind	0	35	136	158	159	160
	Solar	1	12	58	65	71	75
	Geothermal and others	0	0	0	0	0	0
Final Energy Consumption per energy form (ktoe)	Coal	7	5	3	3	3	2
	Oil products	326	343	352	368	383	402
	Gas	0	0	1	11	19	26
	Electricity	187	223	244	269	284	305
	Heat	0	0	0	0	0	0
	Renewables	220	237	243	222	237	249
	Other	0	0	0	0	1	1
Final Energy Consumption per Sector (ktoe)	Industry	23	25	26	28	30	32
	Residential	354	393	407	415	446	477
	Tertiary	85	92	101	107	111	116
	Transport	277	299	308	323	340	360
	Agriculture						
GHG Emissions	ktons of CO_2eq	2200	2400	2500	1400	1500	1700
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	2.18	2.18	2.16	1.44	1.46	1.56
	Emission intensity (tons CO_2eq/ MEuro)	647	615	556	280	263	270
	Import Dependency	30%	28%	27%	36%	38%	41%
	Share of RES in FEC	48%	50%	51%	49%	49%	49%

Romania

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	1165	1566	448	803	861	730
	Crude oil and products	5156	5307	6608	7227	7626	7834
	Gas	839	2175	4480	73	4551	4631
	Electricity	-716	-696	-672	-949	-861	-550
Gross Inland Consumption (ktoe)	Coal	6207	5550	5618	4223	2940	2494
	Oil products	8775	8544	8958	9222	9243	9495
	Gas	9688	10143	10355	10333	10557	10743
	Nuclear	2838	2988	3055	5985	5775	5967
	Electricity	-716	-696	-672	-949	-861	-550
	Renewables	6299	6984	7274	7059	7869	7120
Gross Electricity Generation by source (GWh)	Coal	21982	16894	14195	11997	11000	8551
	Oil products	625	338	403	157	157	157
	Gas	8032	12839	15485	11291	16613	16034
	Nuclear	11890	12519	12800	25075	24196	25000
	Biomass and waste	522	522	522	522	522	504
	Hydro	16112	17737	17401	17415	17434	17500
	Wind	6473	7206	7963	7944	7748	7478
	Solar	1891	2249	3607	4672	6258	6040
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal	815	684	714	711	480	474
	Oil products	6765	6840	7140	7110	7200	7397
	Gas	6337	5928	6188	5925	5760	5937
	Electricity	3683	3990	4165	4385	4800	4931
	Heat	1493	1140	1190	1422	1440	1479
	Renewables	4023	4218	4403	4148	4320	4438
	Other	0	0	0	0	0	0
Final Energy Consumption per Sector (ktoe)	Industry	7316	6840	7140	6873	6480	6657
	Residential	7825	7524	7854	7821	8160	8383
	Tertiary	2468	2508	2618	2370	2400	2466
	Transport	5507	5928	6188	6636	6960	7150
	Agriculture						
GHG Emissions	ktons of CO_2eq	118700	118700	119000	126000	117800	116787
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	3.59	3.54	3.44	3.51	3.32	3.31
	Emission intensity (tons CO_2eq/ MEuro)	751	657	577	553	480	442
	Import Dependency	19%	25%	31%	20%	34%	36%
	Share of RES in FEC	23%	25%	26%	25%	26%	26%

Serbia

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	622	647	723	729	755	843
	Crude oil and products	2236	2917	3040	3340	3538	3816
	Gas	1386	1863	2338	2791	3184	3522
	Electricity	-79	-130	-148	-166	-185	-203
Gross Inland Consumption (ktoe)	Coal	7740	7504	6811	7219	7840	8277
	Oil products	3465	3638	3785	3917	3969	4155
	Gas	1750	2201	2661	3041	3375	3667
	Nuclear	0	0	0	0	0	0
	Electricity	-79	-130	-148	-166	-185	-203
	Renewables	1931	1964	2322	2409	2502	2604
Gross Electricity Generation by source (GWh)	Coal	27130	25255	23068	24792	27082	28797
	Oil products	370	1534	1549	1272	977	909
	Gas	0	0	0	0	0	0
	Nuclear	0	0	0	0	0	0
	Biomass and waste	0	118	359	547	640	790
	Hydro	10790	10433	10469	10469	10469	10469
	Wind	0	971	3690	3690	3721	3737
	Solar	0	53	53	108	282	453
	Geothermal and others	0	0	0	0	0	0
Final Energy Consumption per energy form (ktoe)	Coal	500	812	717	733	797	890
	Oil products	2541	2808	2993	3136	3175	3344
	Gas	744	1118	1414	1657	1929	2237
	Electricity	2338	2503	2617	2714	2845	2970
	Heat	716	562	669	755	800	751
	Renewables	1041	979	996	986	1018	1057
	Other	0	0	0	0	0	0
Final Energy Consumption per Sector (ktoe)	Industry	2103	2541	2884	3162	3487	3817
	Residential	2826	2885	2875	2912	2981	3016
	Tertiary	875	853	944	1051	1179	1302
	Transport	1987	2310	2497	2639	2694	2888
	Agriculture	152	194	205	216	223	228
GHG Emissions	ktons of CO_2eq	67148	58385	57184	60982	65279	69293
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	4.53	3.85	3.71	3.71	3.73	3.75
	Emission intensity (tons CO_2eq/ MEuro)	2215	1662	1333	1193	1055	999
	Import Dependency	28%	35%	39%	41%	42%	43%
	Share of RES in FEC	22%	20%	21%	20%	19%	18%

Slovenia

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	Coal	245	198	151	151	129	107
	Crude oil and products	2360	2200	2221	2241	2157	2073
	Gas	681	780	1004	1228	1414	1599
	Electricity	-36	-10	-35	-49	-41	-33
Gross Inland Consumption (ktoe)	Coal	1268	1024	780	780	666	552
	Oil products	2360	2200	2221	2241	2157	2073
	Gas	681	780	1004	1228	1414	1599
	Nuclear	1322	1386	1450	1450	1451	1451
	Electricity	-36	-10	-35	-49	-41	-33
	Renewables	1182	1147	1215	1248	1186	1223
Gross Electricity Generation by source (GWh)	Coal	4858	5000	4500	4000	3500	3000
	Oil products	0	0	0	0	0	0
	Gas	14	100	1300	2500	3750	5000
	Nuclear	5125	5373	5621	5621	5623	5625
	Biomass and waste	111	134	135	136	136	137
	Hydro	4423	4442	4443	4565	4567	4570
	Wind	5	6	10	15	23	32
	Solar	295	306	427	556	724	904
	Geothermal and others						
Final Energy Consumption per energy form (ktoe)	Coal	51	35	20	5	3	0
	Oil products	2239	2197	2218	2238	2154	2070
	Gas	635	624	658	691	716	740
	Electricity	1098	1182	1244	1305	1391	1476
	Heat	197	176	171	166	161	155
	Renewables	735	792	759	725	688	651
	Other	0	0	1	2	10	17
Final Energy Consumption per Sector (ktoe)	Industry	1332	1310	1357	1403	1442	1481
	Residential	1145	1053	990	927	910	892
	Tertiary	638	602	562	522	506	491
	Transport	1839	2041	2161	2280	2263	2246
	Agriculture						
GHG Emissions	ktons of CO_2eq	17450	17084	16904	16860	16600	16000
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	2.58	2.62	2.55	2.44	2.43	2.33
	Emission intensity (tons CO_2eq/ MEuro)	427	384	346	322	296	268
	Import Dependency	48%	49%	50%	52%	54%	55%
	Share of RES in FEC	22%	23%	22%	22%	22%	21%

Turkey

		2015	2020	2025	2030	2035	2040
Net Imports (ktoe)	21859	25778	30833	33171	31591	32160	
	Crude oil and products	42142	45699	50716	55406	59659	61077
	Gas	39362	41179	28079	30079	33779	36779
	Electricity	339	549	562	574	675	689
Gross Inland Consumption (ktoe)	Coal	34597	40800	48800	52500	50000	50900
	Oil products	38639	41900	46500	50800	54700	56000
	Gas	39383	41200	28100	30100	33800	36800
	Nuclear	0	0	2300	4700	9300	16300
	Electricity	339	549	562	574	675	689
	Renewables	15645	19700	29800	38900	50400	60800
Gross Electricity Generation by source (GWh)	Coal	71971	113000	139500	161100	160700	166100
	Oil products	2412	900	300	377	0	0
	Gas	104154	55100	52600	58800	67100	75800
	Nuclear	0	0	8900	17900	35700	62500
	Biomass and waste	2320	4000	6600	7700	9900	13000
	Hydro	51750	88600	73800	69900	72100	68100
	Wind	6290	21400	38000	50500	72200	93200
	Solar	225	9600	19400	33800	51700	67500
	Geothermal and others	2847	8200	18400	24300	25600	24400
Final Energy Consumption per energy form (ktoe)	Coal	11403	13400	13400	13100	12600	12300
	Oil products	28671	35600	39400	43000	46300	47500
	Gas	21151	23600	28100	30100	33800	36800
	Electricity	18444	22100	26000	31200	36600	42300
	Heat	991	1102	1225	1363	1515	1685
	Renewables	5662	7800	8500	10100	12000	15600
	Other						
Final Energy Consumption per Sector (ktoe)	Industry	26109	37302	40825	44463	49215	55185
	Residential	20141	17437	20359	22802	25116	27625
	Tertiary	12194	15963	18641	20598	23184	26075
	Transport	24502	28400	31900	35600	39200	41000
	Agriculture	3887	4600	5000	5500	6100	6300
GHG Emissions	ktons of CO_2eq	355700	369300	404700	440100	458650	477200
Indicators	Carbon intensity (tons CO_2eq/ toe GIC)	2.77	2.56	2.59	2.48	2.31	2.15
	Emission intensity (tons CO_2eq/ MEuro)	529	461	400	353	317	286
	Import Dependency	81%	79%	71%	67%	63%	59%
	Share of RES in FEC	12%	17%	17%	18%	20%	23%

Disclaimer

On July 20, 2021, the European Commission published the "EU Reference Scenario 2020[27]", one of its key analysis tools in the areas of energy, transport, and climate action. The purpose of this publication is to present the "EU Reference Scenario 2020", which updates the previous version published in 2016. The Reference Scenario projects the impact of macro-economic, fuel price and technology trends and policies on the evolution of the EU energy system, on transport, and on their greenhouse gas (GHG) emissions.

The projections concern the 27 EU Member States individually and altogether. The Reference Scenario also includes GHG emission trends not related to energy. This publication presents and discusses the projection results and analyses various interactions among energy system sectors and impact of different policies. In essence, the Reference Scenario is an informed, internally consistent, and policy relevant projection on the future developments of the EU energy system, transport system and GHG emissions that acts as a benchmark for new policy initiatives. It reflects policies and market trends used by policymakers as baseline for the design of policies that can bridge the gap between where EU energy and climate policy stands today and where it aims to be in the medium- and long-term, notably in 2030 and 2050.

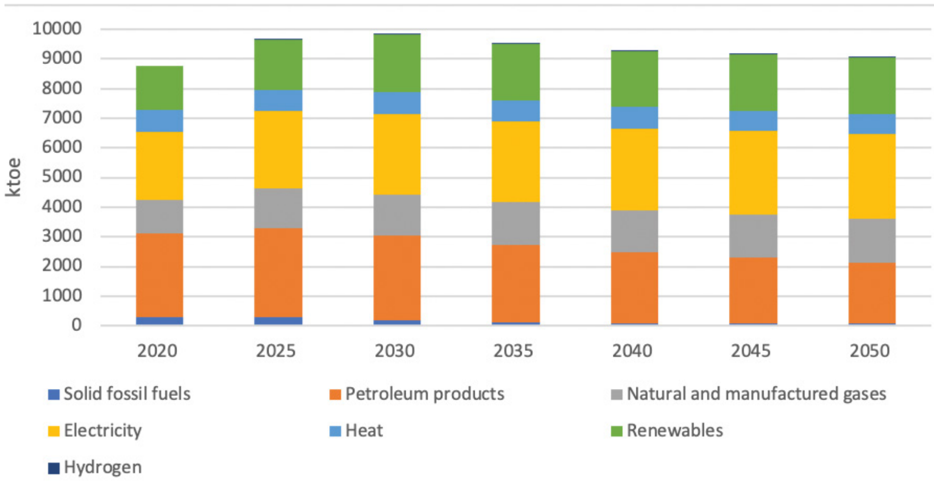
The novelty of this publication lies in that it mirrors the National Energy and Climate Plans (NECPs) of the EU Member States in accordance with the provisions of the Governance Regulation. By doing so, the Reference Scenario has acted as a comprehensive analytical basis of the "Fit for 55" package, since all the policy scenarios explored in that context have been essentially an upscaling of the NECPs.

However, as the projections of the "Baseline" scenario, as analysed in detail in this Chapter, were prepared prior to the publication of the aforementioned "EU Reference Scenario 2020", we consider it necessary for the sake of completeness of the SEEEO 2021/2022 to include the summary tables of projections concerning energy, transport and GHG emissions for the EU Member States of the SE European region, as included in the above "EU Reference Scenario 2020", as shown below.

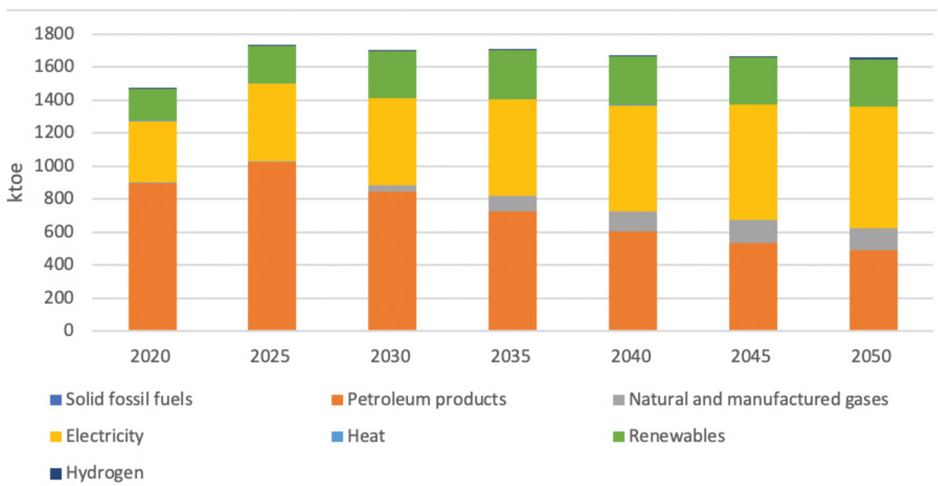
Indicatively, using the summary tables, we produced a Figure for each EU SEE Member State concerning the final energy consumption per fuel between 2020 and 2050.

[27] https://op.europa.eu/en/publication-detail/-/publication/96c2ca82-e85e-11eb-93a8-01aa75ed71a1/language-en

Bulgaria: Final energy consumption by energy form

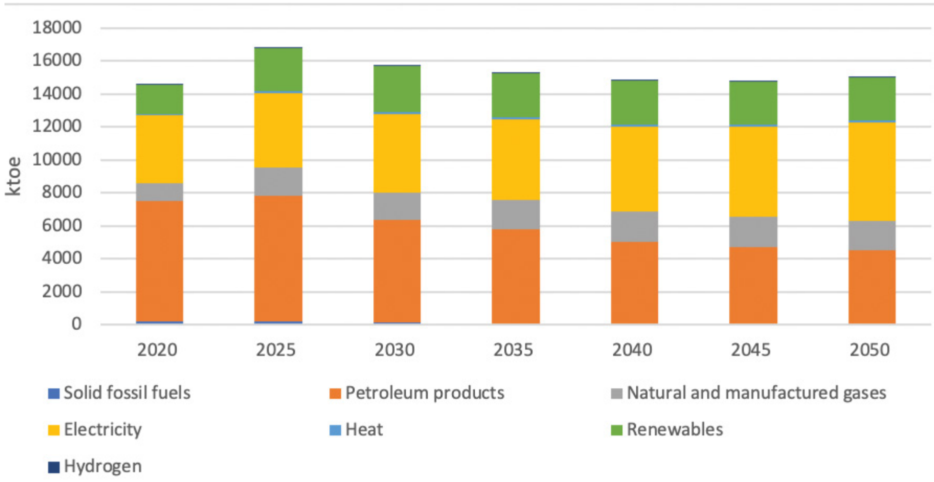


Cyprus: Final energy consumption by energy form

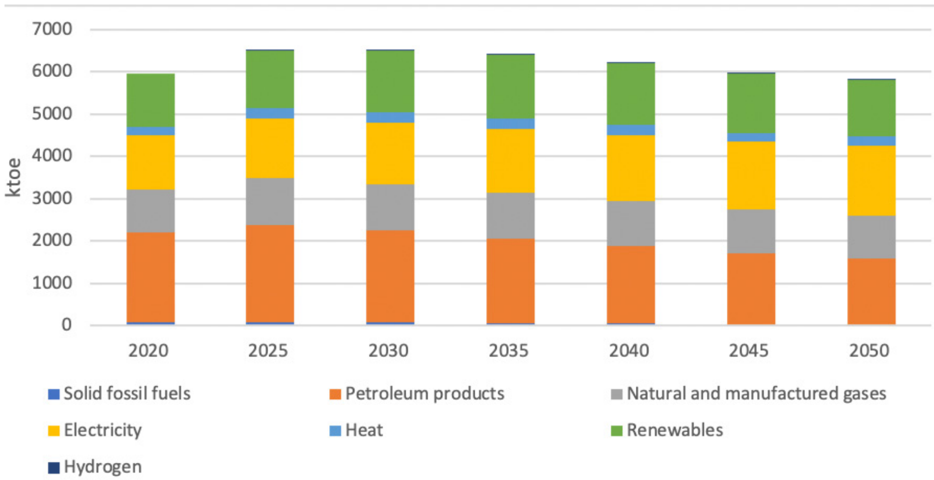


14

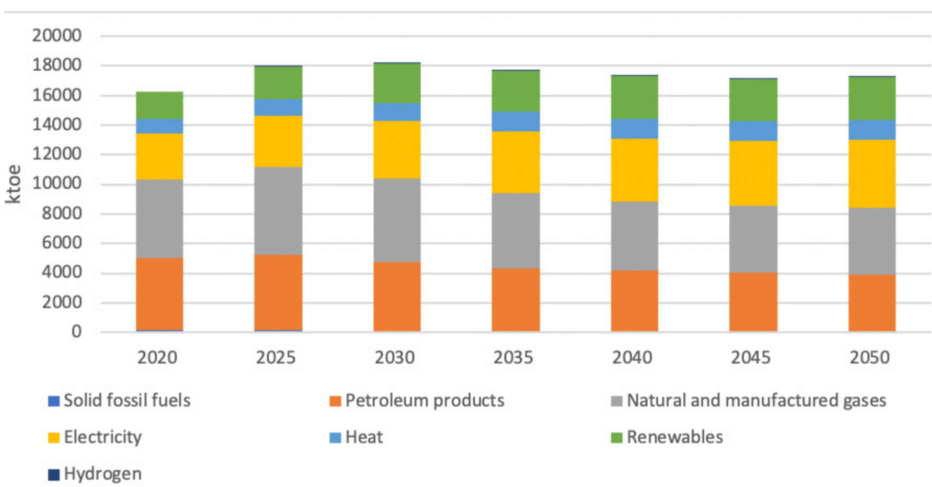
Greece: Final energy consumption by energy form



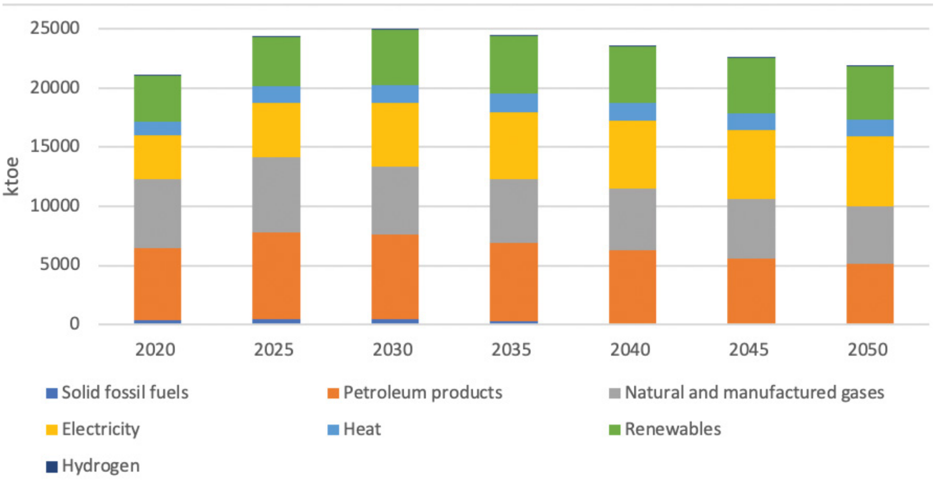
Croatia: Final energy consumption by energy form



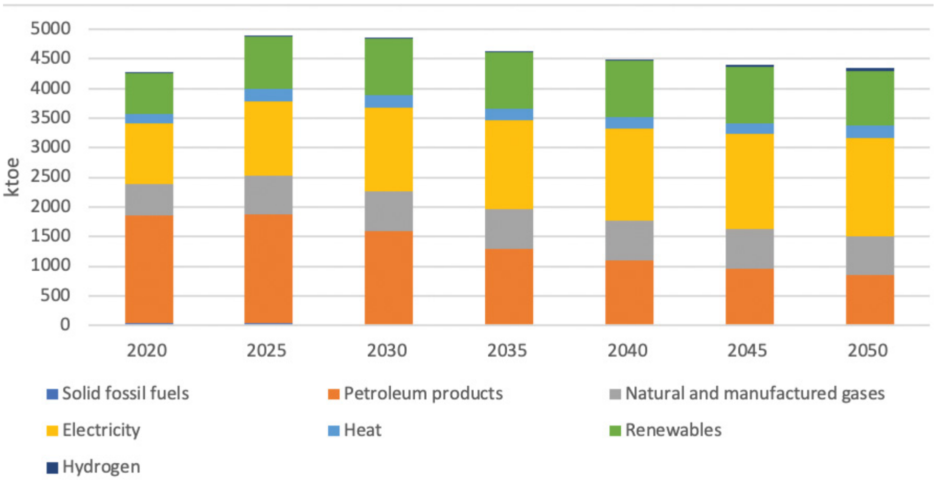
Hungary: Final energy consumption by energy form



Romania: Final energy consumption by energy form



Slovenia: Final energy consumption by energy form



14

Bulgaria:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries [7]
Other industrial sectors
Residential
Tertiary [8]
Transport [9]
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
7,8	**7,4**	**7,2**	**6,9**	**6,7**	**6,5**	**6,2**	**6,0**	**5,8**	**5,7**	**-0,7**	**-0,7**	**-0,7**
36	**42**	**46**	**49**	**55**	**58**	**62**	**66**	**70**	**73**	**1,5**	**1,8**	**1,2**
8,3	5,2	4,7	5,0	4,7	4,4	4,2	3,9	3,7	3,5	-0,4	-1,2	-1,2
27,5	25,0	26,3	25,3	25,4	25,5	25,3	25,1	24,9	24,9	0,1	0,1	-0,1
64,3	69,8	69,1	69,7	69,8	70,0	70,6	71,0	71,4	71,6	0,0	0,1	0,1
65,2	**61,0**	**61,6**	**49,2**	**44,8**	**43,5**	**37,2**	**28,5**	**26,5**	**25,1**	**-2,1**	**-1,2**	**-2,7**
9,1	**14,1**	**18,3**	**23,0**	**28,4**	**29,9**	**34,2**	**37,8**	**41,0**	**41,7**	**5,0**	**2,6**	**1,7**
14,1	25,2	29,7	35,6	40,3	44,5	47,5	47,8	50,1	51,6	3,5	2,2	0,7
8,5	12,3	18,7	22,6	36,3	35,3	45,8	56,6	61,9	60,8	6,3	4,5	2,8
		6,4	9,2	10,0	14,2	17,1	21,3	25,8	28,6	-	4,5	3,5
9,6	**8,8**	**9,6**	**8,8**	**9,8**	**10,0**	**9,7**	**9,4**	**9,3**	**9,2**	**-0,1**	**1,3**	**-0,4**
19,1	**17,4**	**18,3**	**15,7**	**15,6**	**15,6**	**14,7**	**13,2**	**13,3**	**13,5**	**-1,1**	**0,0**	**-0,7**
		0,3	**0,8**	**0,5**	**0,6**	**0,4**	**0,4**	**0,3**	**0,3**	**-**	**-2,9**	**-3,1**
0,27	**0,30**	**0,30**	**0,31**	**0,34**	**0,36**	**0,38**	**0,39**	**0,41**	**0,41**	**0,4**	**1,4**	**0,7**
20091	**17969**	**19017**	**16313**	**16289**	**16446**	**15648**	**14179**	**14251**	**14532**	**-1,0**	**0,1**	**-0,6**
6808	6938	6602	4799	3564	2921	1696	210	143	133	-3,6	-4,8	-14,3
5101	4105	4584	3618	4013	3917	3662	3417	3236	3054	-1,3	0,8	-1,2
2804	2300	2641	1652	1915	2907	3663	3469	3211	3053	-3,3	5,8	0,2
4855	3849	4008	4381	4038	4038	4038	3964	3756	4456	1,3	-0,8	0,5
750	927	1236	1617	1888	2052	2060	2010	2114	2129	5,7	2,4	0,2
373	435	490	254	431	433	433	429	465	465	-5,2	5,5	0,4
0	59	125	125	193	193	299	599	681	669	7,9	4,4	6,4
0	12	141	144	469	482	701	702	704	703	28,7	12,9	1,9
49	70	110	135	143	146	143	142	607	614	6,7	0,8	7,4
0	0	-8	0	-1	0	3	0	0	0	-	-	-40,9
-650	-726	-912	-411	-364	-643	-1050	-763	-667	-744	-5,5	4,6	0,7
9469	**8763**	**9461**	**8773**	**9659**	**9811**	**9518**	**9269**	**9172**	**9044**	**0,0**	**1,1**	**-0,4**
3507	2561	2713	2477	2735	2822	2605	2543	2570	2538	-0,3	1,3	-0,5
2630	1789	1898	1744	1868	1827	1644	1590	1575	1550	-0,3	0,5	-0,8
877	772	815	733	866	995	961	953	995	988	-0,5	3,1	0,0
2090	2243	2193	2186	2288	2322	2357	2366	2367	2345	-0,3	0,6	0,0
1145	1211	1266	1228	1427	1362	1359	1313	1293	1280	0,1	1,0	-0,3
2727	2748	3289	2883	3209	3305	3196	3047	2942	2881	0,5	1,4	-0,7
591	410	331	294	295	198	122	87	73	62	-3,3	-3,9	-5,7
3540	3010	3238	2832	3003	2847	2604	2407	2244	2078	-0,6	0,1	-1,6
1391	1058	1333	1106	1329	1385	1431	1409	1428	1471	0,4	2,3	0,3
2214	2330	2428	2308	2612	2704	2739	2742	2816	2873	-0,1	1,6	0,3
939	960	818	726	724	758	717	725	697	671	-2,8	0,4	-0,6
794	994	1313	1508	1694	1918	1903	1896	1906	1878	4,2	2,4	-0,1
0	0	0	0	0	0	2	4	7	11	-	43,9	29,8
849	**422**	**605**	**491**	**526**	**654**	**702**	**735**	**755**	**772**	**1,5**	**2,9**	**0,8**

14

otal transformation input (ktoe)	
Transformation inputs into Thermal Power Generation and District heating	
Solid fossil fuels	
Petroleum products	
Natural and manufactured gases	
Nuclear	
Hydro, solar, wind and other renewables	
Biomass & Waste [6]	
Geothermal heat	
Hydrogen	
Synthetic hydrocarbons	
Electricity	
Transformation inputs to other transformations	
Transformation inputs into synthetic fuels processes	
Hydrogen	
Electricity	
Total transformation output (ktoe)	
Transformation output of Thermal Power Generation and District heating	
Electricity	
Heat	
Transformation outputs from other transformations	
Transformation outputs of synthetic fuels processes	
Hydrogen	
Synthetic hydrocarbons	
Energy Branch Consumption (ktoe)	
Solid fossil fuels	
Crude oil and petroleum products	
Natural and manufactured gases	
Biomass & Waste[6] and Geothermal heat	
Hydrogen	
Synthetic hydrocarbons	
Electricity	
Heat	
SECURITY OF SUPPLY	
Primary Production (incl. recovery of products) (ktoe)	
Solid fossil fuels	
Crude oil and petroleum products	
Natural gas	
Nuclear	
Renewable energy sources	
Net Imports (ktoe)	
Solid fossil fuels	
Crude oil and petroleum products	
Natural gas	
Electricity	
Biomass	
Hydrogen	
Import Dependency (%) [10]	

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	20907	**18774**	**21993**	**16143**	**15560**	**16110**	**15554**	**13569**	**13459**	**13722**	**-1,5**	**0,0**	**-0,8**
	12183	12036	12057	10080	9025	9274	9152	7713	7871	8389	-1,8	-0,8	-0,5
	5667	6380	6079	4383	3159	2614	1482	57	3	2	-3,7	-5,0	-29,5
	205	233	172	4	0	0	2	0	0	0	-33,9	-100,0	-
	1031	992	948	283	336	1171	1836	1627	1342	1144	-11,8	15,3	-0,1
	4855	3849	4008	4381	4038	4038	4038	3964	3756	4456	1,3	-0,8	0,5
	373	495	734	499	1060	1062	1381	1673	1793	1781	0,1	7,8	2,6
	5	6	54	263	370	323	348	306	391	424	46,1	2,1	1,4
	0	0	0	5	1	2	1	2	455	449	-	-6,1	29,8
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	47	81	62	263	62	64	64	85	131	132	12,5	-13,2	3,7
	8724	6738	9936	6062	6534	6836	6400	5853	5583	5319	-1,1	1,2	-1,2
	0	0	0	0	0	0	1	3	5	14	-	39,4	31,4
	0	0	0	0	0	0	0	0	0	0	-	-	-100,0
	0	0	0	0	0	0	1	3	5	14	-	39,4	31,4
	13007	**11875**	**14978**	**10481**	**10952**	**11616**	**11500**	**10552**	**10269**	**10136**	**-1,2**	**1,0**	**-0,7**
	4950	5292	5322	4620	4608	4967	5253	4813	4785	4895	-1,3	0,7	-0,1
	3815	4011	4232	3674	3685	4020	4396	4005	4015	4157	-0,9	0,9	0,2
	1135	1280	1090	946	923	947	857	807	770	738	-3,0	0,0	-1,2
	8057	6584	9656	5861	6343	6649	6246	5737	5481	5231	-1,2	1,3	-1,2
	0	0	0	0	0	0	1	2	4	11	-	39,8	31,6
	0	0	0	0	0	0	1	2	4	11	-	39,8	31,6
	0	0	0	0	0	0	0	0	0	0	-	-	-
	933	**1005**	**1117**	**805**	**734**	**706**	**599**	**412**	**381**	**365**	**-2,2**	**-1,3**	**-3,2**
	2	1	1	1	0	0	0	0	0	0	-7,8	-4,6	-26,7
	193	319	422	265	270	262	230	194	172	157	-1,8	-0,1	-2,5
	168	27	55	33	36	47	58	66	64	51	2,0	3,6	0,5
	0	0	0	0	0	0	2	3	4	6	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	484	481	506	395	333	310	255	146	141	151	-1,9	-2,4	-3,5
	86	176	133	111	95	87	54	2	0	0	-4,5	-2,4	-25,5
	10640	**10427**	**12093**	**10798**	**10555**	**10268**	**9511**	**8214**	**8596**	**9318**	**0,4**	**-0,5**	**-0,5**
	4172	4945	5826	4253	3221	2667	1516	63	8	5	-1,5	-4,6	-26,7
	30	23	31	7	10	13	16	16	15	15	-11,4	6,0	0,9
	384	59	86	97	127	259	332	336	348	344	5,1	10,3	1,4
	4855	3849	4008	4381	4038	4038	4038	3964	3756	4456	1,3	-0,8	0,5
	1199	1550	2142	2061	3159	3291	3609	3836	4469	4498	2,9	4,8	1,6
	9460	**7232**	**7060**	**5515**	**5733**	**6178**	**6138**	**5968**	**5658**	**5214**	**-2,7**	**1,1**	**-0,8**
	2449	1700	777	546	343	254	181	147	136	128	-10,7	-7,4	-3,4
	5230	4182	4648	3611	4002	3905	3649	3401	3221	3039	-1,5	0,8	-1,2
	2458	2131	2562	1556	1788	2648	3331	3133	2863	2709	-3,1	5,5	0,1
	-650	-726	-912	-411	-364	-643	-1050	-763	-667	-744	-5,5	4,6	0,7
	-26	-55	-14	214	-35	15	28	47	102	82	-	-23,5	9,0
	0	0	0	0	0	0	1	2	4	0	-	-	-
	47,1	40,2	37,1	33,8	35,2	37,6	39,2	42,1	39,7	35,9	-	-	-

Bulgaria:Reference Scenario 2020 (REF2020)

ECONOMIC INDICATORS
Total energy-related costs (in 000 M€15) [11]
as % of GDP
Energy cost indicators
Energy expenditure in households (% of private consumption) [12]
fuel cost
capital cost
Average Cost of Gross Electricity Generation (€'15/MWh)
Average Price of Electricity in Final demand sectors (€'15/MWh) [13]
Energy Intensity indicator
Gross Available Energy/GDP (toe/M€15)

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
7,6	**9,4**	**10,9**	**10,0**	**12,9**	**15,4**	**16,5**	**17,4**	**17,7**	**18,0**	**0,7**	**4,4**	**0,8**
21,2	22,4	23,9	20,6	23,6	26,5	26,6	26,4	25,5	24,6	-0,8	2,5	-0,4
8,8	11,4	10,2	11,5	12,0	13,1	12,3	12,5	11,8	11,4	0,1	1,3	-0,7
5,7	6,0	5,8	5,8	6,2	6,7	6,4	6,2	6,1	5,8	-0,3	1,4	-0,7
3,1	5,3	4,4	5,7	5,8	6,5	5,8	6,2	5,8	5,7	0,6	1,3	-0,7
55,3	57,5	48,7	62,9	65,0	67,5	69,7	71,4	75,2	81,2	0,9	0,7	0,9
56,2	74,9	91,9	97,9	108,8	121,1	121,2	122,7	124,2	124,5	2,7	2,1	0,1
563	430	416	335	298	282	253	215	204	198	-2,4	-1,7	-1,8

Bulgaria:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe) [1]
By transport mean
Buses and coaches
Passenger cars

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	43972	**46017**	**48728**	**40534**	**42340**	**46213**	**50582**	**45871**	**45620**	**47311**	**-1,3**	**1,3**	**0,1**
	18653	15249	15381	16811	15494	15495	15495	15209	14413	17100	1,0	-0,8	0,5
	4359	5802	8673	6900	13835	13665	17574	20951	23426	23503	1,7	7,1	2,7
	17	49	143	1102	1522	1334	1527	1520	2072	2305	36,5	1,9	2,8
	4337	5057	5695	2954	5011	5029	5033	4988	5408	5403	-5,2	5,5	0,4
	4203	4901	5392	2808	4858	4876	4879	4835	5249	5245	-5,4	5,7	0,4
	134	156	303	146	153	153	154	153	159	158	-0,7	0,5	0,1
	5	681	1452	1452	2241	2241	3478	6964	7917	7782	7,9	4,4	6,4
	5	681	1452	1452	2241	2241	2289	5141	5663	5560	7,9	4,4	4,6
	0	0	0	0	0	0	1190	1823	2254	2222	-	-	-
	0	15	1383	1392	5060	5060	7536	7479	7501	7493	57,3	13,8	2,0
	0	0	0	0	0	0	0	0	526	520	-	-	-
	20960	24966	24674	16823	13011	17053	17513	9711	7782	6708	-3,9	0,1	-4,6
	18458	22606	22122	16388	12212	10300	6612	156	1	1	-3,2	-4,5	-37,0
	606	393	582	7	0	0	8	0	0	0	-33,6	-100,0	-
	1896	1967	1970	428	799	6753	10893	9555	7781	6707	-14,1	31,8	0,0
	0	0	0	0	0	0	0	0	0	0	-	-	-
	10635	**9943**	**11987**	**11750**	**15211**	**15145**	**16270**	**16810**	**17073**	**17375**	**1,7**	**2,6**	**0,7**
	2765	1920	1920	1920	1920	1920	1920	1920	1920	2400	0,0	0,0	1,1
	1992	2701	4128	4963	8579	7971	10202	11791	12566	12400	6,3	4,9	2,2
	0	4	28	852	1238	630	631	563	694	528	69,2	-3,0	-0,9
	1984	2184	2372	2376	2509	2509	2509	2509	2682	2682	0,8	0,5	0,3
	1708	1906	2061	2064	2197	2197	2197	2197	2371	2371	0,8	0,6	0,4
	276	278	311	312	312	312	312	312	312	312	1,2	0,0	0,0
	8	488	699	699	1078	1078	1487	3144	3521	3521	3,7	4,4	6,1
	8	488	699	699	1078	1078	1101	2529	2768	2768	3,7	4,4	4,8
	0	0	0	0	0	0	387	615	752	752	-	-	-
	0	25	1029	1036	3753	3753	5575	5575	5575	5575	45,1	13,7	2,0
	0	0	0	0	0	0	0	0	94	94	-	-	-
	5878	5322	5939	4867	4712	5254	4148	3099	2587	2575	-0,9	0,8	-3,5
	5100	4703	5313	4499	4007	3701	2019	1074	674	674	-0,4	-1,9	-8,2
	42	13	13	2	2	2	0	0	0	0	-18,4	0,0	-100,0
	737	606	613	366	703	1551	2129	2025	1914	1901	-4,9	15,5	1,0
	0	0	0	0	0	0	0	0	0	0	-	-	-
	55	64	76	66	80	85	88	90	92	95	0,2	2,6	0,6
	14	11	13	9	11	11	12	12	12	12	-1,9	2,7	0,4
	35	47	57	52	59	64	65	66	67	70	1,1	2,0	0,5
	1	1	1	1	1	2	2	2	2	2	2,4	1,4	0,2
	3	3	2	2	3	3	3	3	3	3	-5,5	5,5	0,9
	3	3	3	2	5	6	6	7	8	8	-3,5	10,8	1,8
	0	0	0	0	0	0	0	0	0	0	5,9	7,0	0,7
	17	18	21	21	24	27	28	30	32	33	1,3	2,6	1,1
	11	9	11	12	13	15	15	16	17	17	2,8	2,4	0,7
	5	3	4	4	5	5	6	7	7	8	2,2	3,4	2,0
	1	6	6	5	6	6	7	7	8	8	-2,1	2,4	1,2
	2507	**2604**	**3107**	**2773**	**3087**	**3165**	**3051**	**2913**	**2821**	**2769**	**0,6**	**1,3**	**-0,7**
	315	231	285	195	249	240	236	238	238	237	-1,7	2,1	-0,1
	1341	1614	2111	1874	2090	2133	2045	1936	1825	1705	1,5	1,3	-1,1

Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2,3]
Freight transport [3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%)[4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula)[5]
Energy intensity indicators
Passenger transport (toe/Mpkm) [2,3]
Freight transport (toe/Mtkm) [3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$) [6]
of which ETS sectors (stationary installations) GHG emissions[7]
International bunkers emissions ($MtCO_2$) [8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport [9]
Other CO_2 Emissions (non land-use related) ($MtCO_2$)
Non-CO2 GHG emissions ($MtCO_2eq$)[6, 10]
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport [9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
19	28	35	34	38	38	39	38	38	38	2,0	1,1	-0,1
739	610	574	592	612	649	621	585	598	664	-0,3	0,9	0,1
70	52	44	30	35	37	39	42	45	46	-5,2	1,8	1,2
13	15	13	8	19	20	20	20	20	21	-6,2	9,2	0,2
10	53	45	39	45	48	53	54	57	57	-3,0	2,1	0,9
2808	**2868**	**3371**	**2933**	**3418**	**3529**	**3437**	**3302**	**3224**	**3185**	**0,2**	**1,9**	**-0,5**
1896	2072	2634	2226	2660	2719	2639	2529	2421	2307	0,7	2,0	-0,8
912	796	737	707	758	810	798	773	803	877	-1,2	1,4	0,4
301	**264**	**263**	**160**	**331**	**365**	**385**	**389**	**403**	**416**	**-4,9**	**8,6**	**0,7**
188	167	177	107	253	275	286	281	284	290	-4,4	9,9	0,3
113	96	87	53	78	90	99	107	120	126	-5,9	5,5	1,7
0,0	0,0	0,0	0,0	0,2	1,3	2,4	2,9	3,8	4,9	-	57,7	6,8
0,0	0,5	4,4	6,5	6,5	7,6	7,3	7,0	7,1	7,1	29,7	1,5	-0,3
		0,8	1,8	2,2	4,0	6,6	9,8	12,0	12,0	-	8,1	5,7
	28,8	31,2	31,6	29,8	28,2	26,2	24,3	22,4	20,6	0,9	-1,1	-1,6
	9,6	6,8	8,2	6,3	5,8	5,2	4,6	4,3	4,4	-1,5	-3,4	
64,8	**60,7**	**61,3**	**49,0**	**44,4**	**43,0**	**36,7**	**28,0**	**26,0**	**24,6**	**-2,1**	**-1,3**	**-2,8**
37,8	35,0	36,3	26,0	21,5	20,8	16,7	9,8	8,7	7,9	-2,9	-2,2	-4,7
0,9	**0,8**	**0,8**	**0,5**	**1,0**	**1,1**	**1,2**	**1,2**	**1,2**	**1,2**	**-4,9**	**8,5**	**0,5**
0,6	0,5	0,5	0,3	0,8	0,8	0,9	0,8	0,8	0,8	-4,4	9,9	0,1
0,4	0,3	0,3	0,2	0,2	0,3	0,3	0,3	0,4	0,4	-5,8	5,5	1,6
45,0	**44,2**	**44,0**	**32,4**	**28,5**	**27,3**	**23,0**	**15,6**	**14,1**	**13,1**	**-3,1**	**-1,7**	**-3,6**
26,9	29,8	28,3	19,1	14,1	13,8	10,6	4,1	3,2	2,7	-4,4	-3,2	-7,8
0,9	1,0	1,3	0,8	0,8	0,9	0,8	0,7	0,6	0,6	-1,6	0,4	-2,0
7,2	3,7	3,7	3,3	3,5	3,1	2,7	2,3	2,2	2,1	-1,3	-0,6	-1,9
1,1	1,0	0,7	0,6	0,6	0,4	0,3	0,3	0,3	0,3	-3,7	-3,8	-2,6
1,1	0,8	0,8	0,7	0,7	0,6	0,6	0,5	0,5	0,4	-1,8	-1,1	-1,8
7,8	7,9	9,1	7,9	8,7	8,6	8,1	7,7	7,3	7,0	0,0	0,9	-1,0
6,8	3,9	5,1	4,6	5,0	5,1	4,3	4,2	4,0	3,9	1,6	1,1	-1,3
14,2	**12,8**	**13,1**	**12,7**	**11,7**	**11,3**	**10,0**	**8,8**	**8,5**	**8,1**	**-0,1**	**-1,2**	**-1,6**
-1,1	**-0,3**	**-0,9**	**-0,8**	**-0,8**	**-0,8**	**-0,7**	**-0,6**	**-0,6**	**-0,6**	**11,4**	**0,0**	**-1,5**
0,61	0,65	0,58	0,47	0,33	0,30	0,21	0,09	0,07	0,06	-3,1	-4,5	-7,9
1,82	1,53	1,52	1,42	1,40	1,30	1,22	1,16	1,12	1,09	-0,7	-0,9	-0,9
2,06	1,46	1,35	1,33	1,28	1,09	1,02	0,92	0,87	0,83	-1,0	-1,9	-1,3
0,50	0,42	0,34	0,30	0,28	0,19	0,12	0,11	0,11	0,11	-3,5	-4,4	-2,7
0,96	0,66	0,65	0,54	0,50	0,44	0,42	0,39	0,35	0,32	-2,0	-2,1	-1,5
2,87	2,88	2,78	2,74	2,71	2,60	2,54	2,52	2,49	2,45	-0,5	-0,5	-0,3

Cyprus:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries[7]
Other industrial sectors
Residential
Tertiary[8]
Transport [9]
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
0,7	**0,8**	**0,8**	**0,9**	**0,9**	**1,0**	**1,0**	**1,0**	**1,0**	**1,0**	**0,8**	**0,8**	**0,4**
17	**19**	**18**	**20**	**22**	**24**	**27**	**30**	**34**	**37**	**0,1**	**2,1**	**2,2**
3,6	2,4	2,1	2,3	2,1	1,9	1,7	1,6	1,5	1,3	-0,3	-2,1	-1,6
19,1	15,4	10,8	14,2	14,0	13,7	13,4	12,9	12,6	12,2	-0,8	-0,3	-0,6
77,3	82,3	87,1	83,5	84,0	84,4	84,8	85,5	86,0	86,5	0,2	0,1	0,1
10,2	**10,1**	**9,1**	**8,0**	**8,0**	**7,5**	**7,2**	**6,7**	**6,5**	**6,3**	**-2,3**	**-0,7**	**-0,9**
3,1	**5,9**	**9,5**	**14,0**	**15,8**	**23,7**	**27,1**	**34,0**	**38,4**	**42,7**	**9,0**	**5,4**	**3,0**
10,0	18,2	24,1	32,6	33,8	37,8	41,4	46,1	47,5	50,7	6,0	1,5	1,5
0,0	1,4	8,7	9,1	14,5	27,6	32,0	45,4	53,3	59,7	20,8	11,7	3,9
		0,6	5,0	5,5	16,1	20,1	27,4	35,8	43,6	-	12,4	5,1
1,8	**1,9**	**1,7**	**1,5**	**2,0**	**2,0**	**2,1**	**2,1**	**2,1**	**2,1**	**-2,2**	**2,8**	**0,2**
2,5	**2,7**	**2,3**	**1,9**	**2,2**	**2,3**	**2,4**	**2,4**	**2,4**	**2,2**	**-3,4**	**1,9**	**-0,3**
		0,6	**0,5**	**1,2**	**1,3**	**0,9**	**0,9**	**0,9**	**1,1**	**-**	**9,0**	**-1,0**
0,44	**0,41**	**0,39**	**0,40**	**0,45**	**0,47**	**0,48**	**0,47**	**0,47**	**0,47**	**-0,1**	**1,6**	**0,0**
2835	**2941**	**2543**	**2152**	**2607**	**2693**	**2828**	**2827**	**2861**	**2712**	**-3,1**	**2,3**	**0,0**
36	17	4	5	6	5	3	2	1	1	-11,8	1,3	-9,8
2743	2812	2370	1910	1569	1509	1514	1435	1405	1216	-3,8	-2,3	-1,1
0	0	0	2	726	732	800	762	747	706	-	80,5	-0,2
0	0	0	0	0	0	0	0	0	0	-	-	-
16	48	70	80	99	141	158	159	156	156	5,3	5,8	0,5
0	0	0	0	0	0	0	0	0	0	-	-	-
0	3	19	19	22	26	35	46	47	81	21,5	3,3	5,7
41	61	79	89	118	204	239	344	424	456	3,8	8,7	4,1
0	1	2	47	66	75	79	79	82	97	51,1	4,7	1,3
0	0	0	0	0	0	0	0	0	0	-	-16,2	-
0	0	0	0	0	0	0	0	0	0	-	-	-
1528	**1642**	**1425**	**1468**	**1731**	**1700**	**1704**	**1671**	**1665**	**1659**	**-1,1**	**1,5**	**-0,1**
320	236	210	220	233	214	215	219	231	227	-0,7	-0,3	0,3
224	173	160	157	167	152	151	158	159	162	-1,0	-0,3	0,3
97	63	50	63	67	61	64	61	71	65	0,1	-0,2	0,3
323	332	327	367	434	474	493	492	501	522	1,0	2,6	0,5
209	309	265	295	384	405	430	441	436	427	-0,5	3,2	0,3
676	765	623	586	679	607	565	520	497	483	-2,6	0,4	-1,1
36	17	4	5	6	5	3	2	1	1	-11,8	1,3	-9,8
1097	1100	938	895	1017	843	723	600	536	492	-2,0	-0,6	-2,7
0	0	0	2	10	38	92	123	136	134	265,9	35,5	6,5
341	420	352	374	467	527	583	645	700	734	-1,2	3,5	1,7
0	0	1	1	1	1	1	1	1	1	26,9	-1,4	0,8
54	105	130	191	230	286	299	297	285	287	6,2	4,1	0,0
0	0	0	0	0	0	1	3	6	9	-	22,2	31,6
73	**85**	**24**	**21**	**25**	**27**	**27**	**27**	**27**	**27**	**-13,0**	**2,6**	**0,0**

14

Cyprus:Reference Scenario 2020 (REF2020)

Total transformation input (ktoe)
Transformation inputs into Thermal Power Generation and District heating
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Nuclear
Hydro, solar, wind and other renewables
Biomass & Waste [6]
Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Transformation inputs to other transformations
Transformation inputs into synthetic fuels processes
Hydrogen
Electricity
Total transformation output (ktoe)
Transformation output of Thermal Power Generation and District heating
Electricity
Heat
Transformation outputs from other transformations
Transformation outputs of synthetic fuels processes
Hydrogen
Synthetic hydrocarbons
Energy Branch Consumption (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Biomass & Waste[6] and Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Heat
SECURITY OF SUPPLY
Primary Production (incl. recovery of products) (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Nuclear
Renewable energy sources
Net Imports (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Electricity
Biomass
Hydrogen
Import Dependency (%) [10]

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	1092	**1208**	**974**	**833**	**811**	**939**	**1091**	**1159**	**1532**	**1787**	**-3,6**	**1,2**	**3,3**
	1088	**1201**	**968**	**815**	**794**	**858**	**931**	**990**	**1075**	**1117**	**-3,8**	**0,5**	**1,3**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	1088	1194	931	771	2	0	10	0	0	0	-4,3	-64,5	-100,0
	0	0	0	0	715	687	694	608	565	514	-	-	-1,4
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	3	30	36	65	149	184	292	377	444	27,1	15,2	5,6
	0	4	7	8	12	12	25	33	38	43	7,0	4,1	6,6
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	10	17	57	96	117	-	-	13,0
	4	**6**	**6**	**18**	**17**	**81**	**160**	**169**	**456**	**670**	**11,0**	**16,1**	**11,1**
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**	**-100,0**	**-**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-100,0	-
	378	**464**	**394**	**549**	**610**	**722**	**841**	**942**	**1323**	**1769**	**1,7**	**2,8**	**4,6**
	376	**458**	**390**	**441**	**507**	**580**	**645**	**747**	**844**	**901**	**-0,4**	**2,8**	**2,2**
	376	458	389	440	505	579	644	746	843	900	-0,4	2,8	2,2
	0	0	1	1	1	1	1	1	1	1	26,9	-1,4	0,8
	1	**6**	**4**	**108**	**103**	**142**	**196**	**195**	**479**	**868**	**33,4**	**2,8**	**9,5**
	0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**	**-100,0**	**-**
	0	0	0	0	0	0	0	0	0	0	-	-100,0	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	21	**19**	**19**	**47**	**14**	**14**	**12**	**9**	**9**	**9**	**9,2**	**-11,5**	**-2,2**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	21	19	19	47	14	14	12	9	9	9	9,2	-11,5	-2,2
	0	0	0	0	0	0	0	0	0	0	-	-	-
	51	**89**	**143**	**204**	**2798**	**4072**	**5653**	**6252**	**8494**	**8034**	**8,7**	**34,9**	**3,5**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	5	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	2519	3682	5202	5679	7815	7278	-	-	3,5
	0	0	0	0	0	0	0	0	0	0	-	-	-
	51	89	138	204	279	390	451	574	679	755	8,7	6,7	3,4
	2855	**2964**	**2468**	**1948**	**-191**	**-1379**	**-2824**	**-3423**	**-5627**	**-5313**	**-4,1**	**-**	**7,0**
	43	11	4	5	6	5	3	2	1	1	-8,0	1,3	-9,8
	2806	2930	2437	1910	1569	1509	1514	1435	1405	1216	-4,2	-2,3	-1,1
	0	0	0	2	-1792	-2950	-4402	-4916	-7069	-6573	-	-	4,1
	0	0	0	0	0	0	0	0	0	0	-	-	-
	6	24	27	32	27	57	60	54	30	34	3,0	6,0	-2,5
	0	0	0	0	0	0	1	3	6	9	-	5031,4	31,6
	100,7	**100,8**	**97,0**	**90,5**	**-7,3**	**-51,2**	**-99,9**	**-121,1**	**-196,7**	**-195,9**	**-**	**-**	**-**

14

Cyprus:Reference Scenario 2020 (REF2020)

ECONOMIC INDICATORS
Total energy-related costs (in 000 M€15) [11]
as % of GDP
Energy cost indicators
Energy expenditure in households (% of private consumption) [12]
fuel cost
capital cost
Average Cost of Gross Electricity Generation (€'15/MWh)
Average Price of Electricity in Final demand sectors (€'15/MWh) [13]
Energy Intensity indicator
Gross Available Energy/GDP (toe/M€15)

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	2,2	**2,9**	**2,7**	**2,4**	**3,5**	**4,2**	**4,5**	**4,8**	**5,0**	**5,3**	**-2,1**	**5,9**	**1,1**
	13,0	15,1	15,1	12,0	15,8	17,4	16,8	16,1	15,0	14,1	-2,3	3,8	-1,1
	3,9	5,1	6,2	6,8	8,6	9,6	9,4	9,5	8,4	7,7	2,9	3,4	-1,1
	3,0	3,0	3,3	3,1	3,5	3,9	4,0	3,7	3,5	3,3	0,3	2,5	-0,9
	0,9	2,1	2,9	3,8	5,1	5,6	5,4	5,9	4,9	4,5	5,9	4,1	-1,2
	115,3	154,3	110,9	81,2	76,4	80,2	84,7	82,6	85,9	82,2	-6,2	-0,1	0,1
	146,3	181,4	173,6	159,1	149,2	160,9	157,7	153,4	157,4	158,5	-1,3	0,1	-0,1
	167	152	143	109	118	111	107	95	85	73	-3,2	0,2	-2,1

Cyprus:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe)[1]
By transport mean
Buses and coaches
Passenger cars

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
4376	**5322**	**4523**	**5118**	**5875**	**6619**	**7300**	**8049**	**8751**	**9188**	**-0,4**	**2,6**	**1,7**
0	0	0	0	0	0	0	0	0	0	-	-	-
0	73	409	484	849	1826	2339	3656	4666	5486	20,8	14,2	5,7
0	35	62	65	99	94	193	257	287	319	6,3	3,8	6,3
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	31	221	222	261	307	402	531	542	940	21,7	3,3	5,7
0	31	221	222	261	307	402	531	542	940	21,7	3,3	5,7
0	0	0	0	0	0	0	0	0	0	-	-	-
0	7	126	198	490	1425	1743	2869	3837	4227	39,7	21,9	5,6
0	0	0	0	0	0	0	0	0	0	-	-	-
4376	5249	4114	4634	5025	4793	4961	4393	4085	3702	-1,2	0,3	-1,3
0	0	0	0	0	0	0	0	0	0	-	-	-
4376	5249	4114	4634	11	0	55	0	0	0	-1,2	-64,8	-100,0
0	0	0	0	5014	4793	4906	4393	4085	3702	-	-	-1,3
0	0	0	0	0	0	0	0	0	0	-	-	-
1119	**1498**	**1696**	**1740**	**2314**	**2961**	**3414**	**3798**	**4368**	**4701**	**1,5**	**5,5**	**2,3**
0	0	0	0	0	0	0	0	0	0	-	-	-
0	92	244	288	493	1140	1370	2019	2616	3008	12,1	14,7	5,0
0	3	10	11	20	21	38	62	77	98	13,4	6,3	8,1
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	82	158	158	178	231	266	322	325	513	6,8	3,8	4,1
0	82	158	158	178	231	266	322	325	513	6,8	3,8	4,1
0	0	0	0	0	0	0	0	0	0	-	-	-
0	7	76	119	295	889	1066	1636	2214	2397	32,8	22,3	5,1
0	0	0	0	0	0	0	0	0	0	-	-	-
1119	1406	1452	1452	1821	1821	2044	1779	1753	1693	0,3	2,3	-0,4
0	0	0	0	0	0	0	0	0	0	-	-	-
1119	1406	1452	1452	1110	1110	964	463	451	200	0,3	-2,7	-8,2
0	0	0	0	712	711	1079	1316	1301	1494	-	-	3,8
0	0	0	0	0	0	0	0	0	0	-	-	-
9	**10**	**10**	**8**	**13**	**15**	**17**	**18**	**19**	**20**	**-2,2**	**6,2**	**1,5**
1	1	1	1	1	1	2	2	2	2	-2,5	4,1	0,7
5	6	6	6	7	8	9	9	10	10	-0,6	3,9	1,1
0	0	0	0	0	0	0	0	0	0	-2,1	2,1	0,8
0	0	0	0	0	0	0	0	0	0	-	-	-
3	3	2	2	4	5	6	7	8	8	-6,3	13,2	2,3
0	0	0	0	0	0	0	0	0	0	-	-	-
1	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**-2,9**	**1,7**	**0,9**
1	1	1	1	1	1	1	1	1	1	-2,9	1,7	0,9
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
676	**765**	**623**	**586**	**679**	**607**	**565**	**520**	**497**	**483**	**-2,6**	**0,4**	**-1,1**
35	36	39	26	36	34	35	34	35	36	-3,4	3,0	0,2
446	580	509	460	537	468	430	395	373	358	-2,3	0,2	-1,3

Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2,3]
Freight transport [3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%) [4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula) [5]
Energy intensity indicators
Passenger transport (toe/Mpkm)[4,3]
Freight transport (toe/Mtkm)[3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$)[6]
of which ETS sectors (stationary installations) GHG emissions[7]
International bunkers emissions ($MtCO_2$)[8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport [9]
Other CO2 Emissions (non land-use related) ($MtCO_2$)
Non-CO2 GHG emissions ($MtCO_2eq$)[6,10]
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport[9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
4	4	3	3	3	3	3	4	4	4	-2,4	1,7	0,4
192	145	71	97	103	101	97	87	85	85	-3,9	0,3	-0,8
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
1269	**1234**	**1110**	**898**	**1292**	**1314**	**1371**	**1390**	**1417**	**1450**	**-3,1**	**3,9**	**0,5**
829	929	818	626	940	944	982	988	979	981	-3,9	4,2	0,2
440	305	292	272	352	370	388	402	437	469	-1,2	3,1	1,2
593	**469**	**487**	**313**	**613**	**707**	**805**	**870**	**919**	**967**	**-4,0**	**8,5**	**1,6**
307	284	245	127	343	415	488	527	536	550	-7,8	12,6	1,4
287	184	242	186	270	292	317	343	384	417	0,1	4,6	1,8
0,0	0,0	0,0	0,1	0,2	2,3	3,2	4,6	5,9	7,2	-	41,2	5,9
0,0	1,2	0,9	2,0	1,7	4,4	4,4	4,1	4,2	4,4	5,3	8,1	0,0
		0,0	0,8	1,7	3,8	7,5	11,1	14,9	17,1	-	16,9	7,9
	47,7	39,5	44,3	32,6	27,5	24,9	22,4	20,6	19,3	-0,7	-4,7	-1,8
	31,6	17,3	19,0	16,7	16,1	15,4	14,7	14,2	13,9	-5,0	-1,7	-0,7
9,2	**9,4**	**8,3**	**7,5**	**7,1**	**6,5**	**6,1**	**5,5**	**5,2**	**4,9**	**-2,3**	**-1,4**	**-1,4**
5,0	5,0	4,4	3,8	3,1	2,9	2,8	2,5	2,4	2,4	-2,7	-2,8	-1,0
1,8	**1,4**	**1,5**	**1,0**	**1,9**	**2,2**	**2,5**	**2,6**	**2,8**	**2,9**	**-3,9**	**8,4**	**1,4**
0,9	0,9	0,7	0,4	1,0	1,2	1,5	1,6	1,6	1,6	-7,8	12,6	1,3
0,9	0,6	0,8	0,6	0,9	0,9	1,0	1,1	1,2	1,3	0,0	4,6	1,6
7,1	**7,4**	**6,0**	**5,4**	**4,9**	**4,4**	**4,1**	**3,5**	**3,3**	**3,0**	**-3,1**	**-2,0**	**-1,9**
3,5	3,8	3,0	2,5	1,7	1,6	1,7	1,4	1,3	1,2	-4,2	-4,3	-1,4
0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-	-	-
1,0	0,7	0,6	0,6	0,6	0,5	0,4	0,3	0,4	0,3	-0,9	-2,5	-1,8
0,5	0,4	0,4	0,3	0,4	0,5	0,4	0,2	0,2	0,2	-1,0	3,4	-4,5
0,1	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,1	-0,5	-0,2	-3,6
2,0	2,2	1,8	1,7	2,0	1,6	1,5	1,3	1,2	1,2	-2,8	-0,6	-1,5
0,9	**0,6**	**0,9**	**0,9**	**0,9**	**0,9**	**0,8**	**0,9**	**0,9**	**0,9**	**3,3**	**0,4**	**0,0**
1,3	**1,3**	**1,3**	**1,2**	**1,2**	**1,2**	**1,0**	**1,1**	**1,0**	**1,0**	**-1,0**	**-0,3**	**-0,9**
-0,1	**0,1**	**0,1**	**0,1**	**0,1**	**0,1**	**0,1**	**0,1**	**0,0**	**0,0**	**-3,5**	**1,5**	**-2,7**
0,80	0,72	0,66	0,49	0,29	0,24	0,23	0,18	0,15	0,13	-3,9	-6,7	-3,0
2,35	2,13	2,11	1,95	1,88	1,62	1,44	1,26	1,16	1,08	-0,9	-1,8	-2,0
3,16	2,87	2,99	2,82	2,66	2,26	1,81	1,59	1,52	1,48	-0,2	-2,2	-2,1
1,44	1,11	1,08	0,91	1,03	0,98	0,81	0,50	0,39	0,36	-2,0	0,8	-4,9
0,43	0,69	0,73	0,69	0,58	0,49	0,47	0,44	0,35	0,23	0,0	-3,3	-3,8
3,01	2,93	2,94	2,90	2,89	2,64	2,60	2,55	2,49	2,44	-0,1	-0,9	-0,4

Greece:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries [7]
Other industrial sectors
Residential
Tertiary [8]
Transport [9]
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	11,1	**11,2**	**10,9**	**10,7**	**10,5**	**10,3**	**10,1**	**9,9**	**9,7**	**9,5**	**-0,4**	**-0,4**	**-0,4**
	220	**217**	**177**	**168**	**195**	**200**	**212**	**231**	**251**	**272**	**-2,5**	**1,8**	**1,5**
	3,8	3,3	4,3	4,5	4,0	3,9	3,7	3,5	3,3	3,0	3,3	-1,5	-1,2
	20,1	16,7	14,6	15,6	16,4	16,3	16,0	15,4	14,9	14,5	-0,7	0,4	-0,6
	76,1	80,0	81,1	79,9	79,6	79,8	80,3	81,2	81,8	82,4	0,0	0,0	0,2
	142,0	**125,0**	**98,5**	**72,9**	**68,1**	**59,5**	**56,6**	**52,8**	**49,2**	**49,6**	**-5,3**	**-2,0**	**-0,9**
	7,0	**9,7**	**15,8**	**22,1**	**26,3**	**37,9**	**40,1**	**43,7**	**49,0**	**49,6**	**8,6**	**5,5**	**1,4**
	12,8	17,4	26,9	28,2	36,0	44,1	44,7	47,5	48,5	49,7	5,0	4,6	0,6
	8,2	12,3	22,3	34,2	42,1	65,6	68,6	72,0	81,3	77,9	10,8	6,7	0,9
			1,2	8,0	10,2	18,0	26,1	34,0	41,5	45,9	-	8,4	4,8
	21,0	**19,0**	**16,6**	**14,7**	**17,3**	**16,2**	**15,9**	**15,5**	**15,5**	**15,7**	**-2,5**	**1,0**	**-0,2**
	30,1	**27,1**	**23,3**	**18,8**	**20,3**	**18,8**	**18,7**	**19,1**	**19,5**	**20,3**	**-3,6**	**0,0**	**0,4**
			0,5	**0,8**	**0,8**	**1,0**	**0,8**	**0,7**	**0,4**	**0,5**	**-**	**2,9**	**-3,1**
	0,50	**0,42**	**0,41**	**0,38**	**0,44**	**0,43**	**0,42**	**0,42**	**0,41**	**0,40**	**-0,8**	**1,0**	**-0,3**
	33748	**30941**	**25997**	**21328**	**23747**	**22429**	**22359**	**23013**	**23523**	**24464**	**-3,7**	**0,5**	**0,4**
	8952	7863	5602	1798	212	149	96	55	44	54	-13,7	-22,1	-4,9
	20449	17117	13735	10938	12245	10482	10143	9396	9018	8832	-4,4	-0,4	-0,9
	2354	3235	2680	4552	5647	5068	5419	5282	4665	5304	3,5	1,1	0,2
	0	0	0	0	0	0	0	0	0	0	-	-	-
	1015	1076	1407	1262	1742	1795	1712	1627	1641	1650	1,6	3,6	-0,4
	431	641	527	216	545	579	574	573	623	635	-10,3	10,3	0,5
	109	233	397	773	1022	1861	2085	2357	2747	2934	12,7	9,2	2,3
	101	197	594	676	1035	1640	1713	1740	2028	2049	13,1	9,3	1,1
	12	89	228	363	499	608	586	1842	2629	2873	15,1	5,3	8,1
	0	0	0	0	0	0	0	0	0	0	-100,0	-	-
	325	491	826	750	801	246	30	139	129	132	4,3	-10,6	-3,0
	20166	**18356**	**15983**	**14568**	**16759**	**15704**	**15275**	**14825**	**14810**	**15032**	**-2,3**	**0,8**	**-0,2**
	4168	3471	3127	2794	3242	3005	3023	2992	3039	3016	-2,1	0,7	0,0
	2588	2226	1960	1756	2084	2014	1947	1908	1928	1888	-2,3	1,4	-0,3
	1580	1245	1166	1038	1159	992	1075	1084	1110	1128	-1,8	-0,5	0,6
	5518	4617	4462	4116	4639	4471	4329	4229	4111	3933	-1,1	0,8	-0,6
	3104	2823	2611	2314	2853	2781	2726	2762	2953	3443	-2,0	1,9	1,1
	7376	7444	5783	5344	6025	5447	5197	4842	4706	4641	-3,3	0,2	-0,8
	443	302	221	201	212	149	96	55	44	54	-4,0	-2,9	-4,9
	13636	11427	8587	7327	7648	6236	5696	4987	4661	4446	-4,3	-1,6	-1,7
	586	782	972	1042	1680	1628	1752	1807	1857	1805	2,9	4,6	0,5
	4377	4568	4367	4137	4539	4777	4922	5189	5477	5979	-1,0	1,4	1,1
	49	46	50	56	74	90	120	124	125	121	1,9	4,9	1,5
	1075	1231	1785	1805	2607	2823	2682	2649	2615	2579	3,9	4,6	-0,5
	0	0	0	0	0	1	6	15	31	48	-	16,2	24,2
	768	**1108**	**700**	**708**	**777**	**856**	**867**	**879**	**896**	**913**	**-4,4**	**1,9**	**0,3**

Greece:Reference Scenario 2020 (REF2020)

Total transformation input (ktoe)
Transformation inputs into Thermal Power Generation and District heating
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Nuclear
Hydro, solar, wind and other renewables
Biomass & Waste [6]
Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Transformation inputs to other transformations
Transformation inputs into synthetic fuels processes
Hydrogen
Electricity
Total transformation output (ktoe)
Transformation output of Thermal Power Generation and District heating
Electricity
Heat
Transformation outputs from other transformations
Transformation outputs of synthetic fuels processes
Hydrogen
Synthetic hydrocarbons
Energy Branch Consumption (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Biomass & Waste[6] and Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Heat
SECURITY OF SUPPLY
Primary Production (incl. recovery of products) (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Nuclear
Renewable energy sources
Net Imports (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Electricity
Biomass
Hydrogen

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	35615	**35306**	**40350**	**24670**	**26785**	**25780**	**25954**	**26009**	**26860**	**27822**	**-3,5**	**0,4**	**0,4**
	13065	**12106**	**9630**	**6970**	**6108**	**6608**	**7178**	**8318**	**9413**	**10346**	**-5,4**	**-0,5**	**2,3**
	8693	7567	5402	1597	0	0	0	0	0	0	-14,4	-100,0	-
	2102	1508	1545	797	469	19	164	65	17	27	-6,2	-31,3	1,8
	1605	2061	1317	3097	3409	2692	2787	2493	1755	2300	4,2	-1,4	-0,8
	0	0	0	0	0	0	0	0	0	0	-	-	-
	540	888	1259	1383	2121	3547	3806	4097	4844	5079	4,5	9,9	1,8
	52	79	101	90	102	92	146	162	177	181	1,3	0,1	3,5
	0	0	0	0	0	0	0	1170	1918	2144	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	72	3	6	6	6	258	275	330	702	615	6,6	46,0	4,4
	22550	**23200**	**30719**	**17700**	**20676**	**19171**	**18767**	**17666**	**17399**	**17401**	**-2,7**	**0,8**	**-0,5**
	0	**0**	**0**	**0**	**0**	**1**	**9**	**24**	**48**	**75**	**-**	**15,7**	**25,2**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	1	9	24	48	75	-	15,7	25,2
	28379	**28725**	**35807**	**22146**	**25491**	**25056**	**25086**	**24231**	**24664**	**25194**	**-2,6**	**1,2**	**0,0**
	5210	**4981**	**4510**	**4108**	**4418**	**5537**	**5984**	**6250**	**6955**	**7479**	**-1,9**	**3,0**	**1,5**
	5161	4935	4460	4051	4339	5437	5848	6102	6804	7330	-2,0	3,0	1,5
	49	46	50	57	79	100	136	148	151	149	2,2	5,7	2,0
	23169	**23743**	**31296**	**18037**	**21072**	**19518**	**19095**	**17963**	**17673**	**17658**	**-2,7**	**0,8**	**-0,5**
	0	**0**	**0**	**0**	**0**	**1**	**7**	**18**	**36**	**57**	**-**	**16,0**	**25,3**
	0	0	0	0	0	1	7	18	36	57	-	16,0	25,3
	0	0	0	0	0	0	0	0	0	0	-	-	-
	1713	**1609**	**1789**	**1172**	**1248**	**1390**	**1396**	**1381**	**1293**	**1384**	**-3,1**	**1,7**	**0,0**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	1129	1061	1285	882	913	854	756	683	603	572	-1,8	-0,3	-2,0
	29	19	12	31	161	319	399	442	443	516	5,3	26,2	2,4
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	555	530	492	257	170	207	225	232	220	267	-7,0	-2,2	1,3
	0	0	0	2	4	10	16	24	27	28	-	19,5	5,4
	10323	**9515**	**8742**	**4673**	**4790**	**7375**	**7765**	**9430**	**10742**	**11724**	**-6,9**	**4,7**	**2,3**
	8538	7315	5670	1599	41	0	0	0	0	0	-14,1	-91,2	-15,0
	99	113	77	43	53	50	48	0	0	0	-9,2	1,5	-100,0
	18	8	5	21	548	1408	1582	1801	1749	2278	10,6	52,4	2,4
	0	0	0	0	0	0	0	0	0	0	-	-	-
	1668	2079	2990	3010	4149	5916	6135	7629	8992	9447	3,8	7,0	2,4
	23015	**21163**	**18301**	**16654**	**18957**	**15054**	**14594**	**13580**	**12776**	**12730**	**-2,4**	**-1,0**	**-0,8**
	371	401	160	198	171	149	96	55	44	54	-6,8	-2,8	-4,9
	19986	16884	14480	10895	12192	10432	10094	9396	9018	8832	-4,3	-0,4	-0,8
	2332	3231	2677	4531	5099	3660	3837	3482	2916	3026	3,4	-2,1	-0,9
	325	491	826	750	801	246	30	139	129	132	4,3	-10,6	-3,0
	0	157	157	281	694	568	536	511	675	695	6,0	7,3	1,0
	0	0	0	0	0	0	-1	-3	-6	-9	-	-	-

Greece:Reference Scenario 2020 (REF2020)

2005 2010
Import Dependency (%) (10)
ECONOMIC INDICATORS
Total energy-related costs (in 000 M€15) [11]
as % of GDP
Energy cost indicators
Energy expenditure in households (% of private consumption) [12]
fuel cost
capital cost
Average Cost of Gross Electricity Generation (€'15/MWh)
Average Price of Electricity in Final demand sectors (€'15/MWh)[13]
Energy Intensity indicator
Gross Available Energy/GDP (toe/M€15)

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50		
68,2	**68,4**	**70,4**	**78,1**	**79,8**	**67,1**	**65,3**	**59,0**	**54,3**	**52,0**	**-**	**-**	**-**
23,7	**31,2**	**26,4**	**25,6**	**33,8**	**37,2**	**38,1**	**38,5**	**39,1**	**40,5**	**-2,0**	**3,8**	**0,4**
10,7	14,4	14,9	15,2	17,3	18,6	17,9	16,7	15,6	14,9	0,6	2,0	-1,1
3,7	5,2	6,1	7,3	7,4	8,1	7,5	7,2	6,6	6,0	3,5	1,0	-1,5
2,9	3,7	4,0	3,9	3,6	3,6	3,4	3,1	2,9	2,5	0,5	-0,6	-1,7
0,8	1,6	2,1	3,5	3,9	4,4	4,1	4,1	3,7	3,4	8,3	2,5	-1,3
63,0	72,0	71,7	76,6	66,7	68,8	70,1	67,9	63,0	64,3	0,6	-1,1	-0,3
78,1	108,1	131,6	136,1	138,6	146,6	149,4	137,4	134,6	134,2	2,3	0,7	-0,4
153	143	147	127	122	112	105	100	94	90	-1,2	-1,2	-1,1

14

Greece:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe) [1]
By transport mean
Buses and coaches

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
59427	**57367**	**51814**	**47052**	**50405**	**60587**	**65174**	**67533**	**71631**	**78639**	**-2,0**	**2,6**	**1,3**
0	0	0	0	0	0	0	0	0	0	-	-	-
6506	10651	15091	16489	25127	41638	44957	49799	59423	62450	4,5	9,7	2,0
222	319	452	410	459	388	705	793	870	903	2,6	-0,6	4,3
5017	7460	6125	2517	6342	6731	6676	6668	7248	7388	-10,3	10,3	0,5
4950	7320	5701	2101	5277	5485	5429	5421	5427	5431	-11,7	10,1	0,0
67	140	423	416	1065	1247	1247	1247	1821	1957	11,5	11,6	2,3
1266	2714	4615	8992	11881	21644	24250	27409	31937	34111	12,7	9,2	2,3
1266	2714	4615	8992	11881	18015	20598	23676	28100	27121	12,7	7,2	2,1
0	0	0	0	0	3630	3652	3733	3837	6990	-	-	3,3
1	158	3900	4570	6445	12874	13326	13568	17138	17555	40,0	10,9	1,6
0	0	0	0	0	0	0	1361	2230	2493	-	-	-
52921	46716	36723	30563	25278	18949	20217	17734	12208	16189	-4,2	-4,7	-0,8
35543	30797	22536	6885	0	0	0	0	0	0	-13,9	-100,0	-
9207	6089	6385	4012	2395	69	827	308	78	126	-4,1	-33,4	3,1
8171	9830	7803	19667	22883	18880	19390	17426	12130	16063	7,2	-0,4	-0,8
0	0	0	0	0	0	0	0	0	0	-	-	-
13208	**15889**	**19028**	**21811**	**21355**	**30177**	**30630**	**30956**	**32187**	**32797**	**3,2**	**3,3**	**0,4**
0	0	0	0	0	0	0	0	0	0	-	-	-
3663	4864	8297	10901	13562	21607	22990	24477	28538	29309	8,4	7,1	1,5
65	149	336	219	292	383	570	609	527	490	3,9	5,8	1,2
3106	3215	3266	3543	3822	3976	3976	3976	4191	4242	1,0	1,2	0,3
2936	3033	3033	3223	3412	3495	3495	3495	3495	3495	0,6	0,8	0,0
170	182	233	320	410	480	480	480	695	747	5,8	4,1	2,2
491	1298	2091	4070	5067	8385	9282	10333	11763	12240	12,1	7,5	1,9
491	1298	2091	4070	5067	7181	8070	9089	10480	9933	12,1	5,8	1,6
0	0	0	0	0	1204	1212	1244	1283	2308	-	-	3,3
1	202	2604	3070	4381	8864	9163	9321	11667	11900	31,3	11,2	1,5
0	0	0	0	0	0	0	238	390	436	-	-	-
9546	11025	10731	10910	7793	8570	7639	6479	3649	3488	-0,1	-2,4	-4,4
4754	4312	3923	3912	50	50	50	50	50	50	-1,0	-35,3	0,0
2625	2618	2022	1822	833	703	566	379	370	144	-3,6	-9,1	-7,6
2166	4095	4786	5175	6911	7817	7024	6050	3229	3294	2,4	4,2	-4,2
0	0	0	0	0	0	0	0	0	0	-	-	-
145	**155**	**158**	**136**	**178**	**189**	**198**	**202**	**208**	**214**	**-1,3**	**3,3**	**0,6**
22	21	21	16	21	22	22	24	24	24	-3,0	3,4	0,5
85	100	98	97	111	117	120	119	119	121	-0,3	1,9	0,2
5	6	6	6	6	7	7	7	8	8	-0,1	1,4	0,9
3	3	3	2	3	3	4	4	4	5	-5,3	6,5	1,8
23	18	22	12	30	34	38	41	45	48	-3,7	10,7	1,8
7	7	8	4	7	7	8	8	8	8	-6,1	6,6	0,4
34	**38**	**27**	**28**	**32**	**33**	**34**	**36**	**37**	**38**	**-2,9**	**1,7**	**0,7**
24	30	19	21	24	25	26	27	27	28	-3,7	1,7	0,7
1	1	0	0	0	0	0	0	0	1	-5,6	2,1	0,9
9	7	7	7	8	8	8	9	9	9	0,0	1,5	0,9
7362	**7432**	**5768**	**5333**	**6007**	**5428**	**5177**	**4821**	**4685**	**4618**	**-3,3**	**0,2**	**-0,8**
437	400	392	281	357	351	346	353	351	346	-3,5	2,3	-0,1

Greece:Reference Scenario 2020 (REF2020)

Passenger cars
Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2, 3]
Freight transport [3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%) [4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula)[5]
Energy intensity indicators
Passenger transport (toe/Mpkm) [2, 3]
Freight transport (toe/Mtkm) [3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$) [6]
of which ETS sectors (stationary installations) GHG emissions [7]
International bunkers emissions ($MtCO_2$) [8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport [9]
Other CO_2 Emissions (non land-use related) ($MtCO_2$)
Non-CO_2GHG emissions ($MtCO_2eq$) [6,10]
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport [9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
4212	4283	3465	3389	3607	3079	2812	2458	2307	2215	-2,3	-1,0	-1,6
174	203	213	189	204	208	210	213	219	225	-0,7	1,0	0,4
1427	1569	935	969	1007	942	921	886	876	885	-4,7	-0,3	-0,3
46	24	61	35	46	44	44	43	41	40	3,8	2,3	-0,5
414	237	167	89	220	235	262	279	295	310	-9,3	10,1	1,4
651	717	534	381	566	569	582	590	595	597	-6,1	4,1	0,2
11029	**10824**	**8374**	**7276**	**9236**	**8732**	**8671**	**8491**	**8513**	**8584**	**-3,9**	**1,8**	**-0,1**
7178	6978	6026	4915	6419	5973	5887	5663	5616	5606	-3,4	2,0	-0,3
3851	3846	2349	2362	2817	2759	2784	2828	2898	2978	-4,8	1,6	0,4
3667	**3392**	**2607**	**1944**	**3229**	**3303**	**3494**	**3670**	**3829**	**3966**	**-5,4**	**5,4**	**0,9**
797	682	824	439	1067	1123	1243	1300	1357	1415	-4,3	9,9	1,2
2869	2710	1783	1505	2161	2180	2250	2370	2472	2551	-5,7	3,8	0,8
0,0	0,0	0,0	0,0	0,3	2,1	2,9	4,8	5,3	5,8	-	53,1	5,1
0,0	0,8	1,7	5,0	4,1	4,6	4,6	4,5	5,0	5,5	19,6	-0,9	0,9
		0,3	0,1	1,8	5,6	16,3	19,0	22,7	25,7	-	49,1	7,9
	21,7	19,7	22,5	18,8	16,6	15,5	14,1	13,4	12,8	0,4	-3,0	-1,3
	17,1	5,6	6,2	5,3	5,1	5,0	4,8	4,7	4,6	-9,7	-1,9	-0,5
136,4	**119,0**	**93,9**	**69,4**	**62,6**	**53,9**	**50,8**	**46,8**	**43,0**	**43,3**	**-5,2**	**-2,5**	**-1,1**
73,1	62,4	50,2	29,4	22,2	18,0	17,7	16,3	14,1	15,3	-7,2	-4,8	-0,8
11,6	**10,8**	**8,2**	**6,1**	**10,1**	**10,3**	**10,8**	**11,2**	**11,5**	**11,8**	**-5,5**	**5,3**	**0,7**
2,4	2,0	2,5	1,3	3,2	3,4	3,7	3,8	3,9	4,1	-4,3	9,9	0,9
9,2	8,7	5,7	4,8	6,9	6,9	7,1	7,4	7,6	7,7	-5,7	3,6	0,6
104,2	**90,3**	**70,3**	**46,7**	**41,1**	**33,5**	**32,4**	**29,1**	**26,0**	**26,6**	**-6,4**	**-3,3**	**-1,1**
55,9	48,9	36,1	18,1	9,4	6,4	7,0	6,0	4,2	5,5	-9,5	-9,9	-0,8
3,3	3,2	4,1	2,8	3,3	3,4	3,4	3,2	3,0	3,1	-1,2	2,0	-0,6
8,8	6,7	6,3	5,4	5,9	4,3	4,1	3,7	3,6	3,3	-2,1	-2,3	-1,2
9,9	6,7	5,3	4,5	4,2	3,5	3,2	2,8	2,6	2,3	-4,0	-2,2	-2,1
4,3	2,8	1,6	1,1	1,5	1,1	0,8	0,6	0,5	0,5	-8,6	-0,6	-3,4
22,0	22,0	16,8	14,8	16,8	14,8	13,9	12,7	12,2	11,9	-3,9	-0,1	-1,1
9,7	**6,7**	**5,8**	**5,7**	**7,0**	**7,0**	**5,8**	**5,9**	**6,0**	**6,1**	**-1,6**	**2,1**	**-0,7**
22,2	**21,1**	**18,5**	**18,0**	**15,9**	**14,6**	**13,7**	**12,7**	**11,8**	**11,4**	**-1,6**	**-2,1**	**-1,2**
0,2	**0,9**	**-0,7**	**-1,1**	**-1,4**	**-1,2**	**-1,1**	**-0,9**	**-0,9**	**-0,8**	**-**	**1,4**	**-2,1**
0,94	0,85	0,70	0,38	0,19	0,11	0,11	0,09	0,06	0,07	-7,7	-12,1	-2,0
2,23	2,08	1,88	1,77	1,70	1,51	1,44	1,34	1,27	1,21	-1,6	-1,6	-1,1
2,12	1,92	2,02	1,93	1,83	1,42	1,37	1,23	1,18	1,11	0,0	-3,0	-1,2
1,79	1,45	1,20	1,08	0,90	0,79	0,73	0,67	0,62	0,59	-2,9	-3,1	-1,4
1,38	0,99	0,63	0,49	0,52	0,38	0,30	0,21	0,17	0,15	-6,7	-2,4	-4,5
2,98	2,95	2,90	2,78	2,79	2,71	2,68	2,63	2,60	2,57	-0,6	-0,3	-0,3

Croatia:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries [6]
Other industrial sectors
Residential
Tertiary [8]
Transport [9]
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
4,3	**4,3**	**4,2**	**4,1**	**3,9**	**3,8**	**3,7**	**3,6**	**3,5**	**3,4**	**-0,6**	**-0,6**	**-0,6**
44	**45**	**45**	**46**	**51**	**53**	**55**	**60**	**64**	**68**	**0,2**	**1,4**	**1,3**
4,9	4,7	3,6	3,7	3,4	3,3	3,2	3,1	2,9	2,8	-2,3	-1,0	-0,9
29,8	27,1	25,4	24,6	24,7	24,5	24,2	23,8	23,4	23,0	-0,9	-0,1	-0,3
65,2	68,3	71,0	71,7	71,9	72,2	72,6	73,1	73,7	74,2	0,5	0,1	0,1
30,4	**28,6**	**24,6**	**21,0**	**20,2**	**18,9**	**17,5**	**16,8**	**15,9**	**15,1**	**-3,0**	**-1,1**	**-1,1**
12,8	**14,3**	**28,4**	**32,4**	**33,9**	**37,4**	**40,8**	**43,0**	**45,3**	**46,8**	**8,5**	**1,4**	**1,1**
10,9	13,1	37,7	36,7	38,3	43,2	45,6	47,5	49,1	49,1	10,9	1,7	0,6
32,8	34,2	44,7	51,5	59,7	64,4	70,7	73,7	75,9	77,8	4,2	2,3	0,9
		1,9	9,9	10,3	14,4	20,4	26,1	35,4	41,8	-	3,8	5,5
7,2	7,2	6,6	6,0	6,6	6,6	6,5	6,3	6,0	5,9	-1,8	1,0	-0,6
9,1	**8,9**	**8,0**	**7,2**	**7,5**	**7,6**	**7,4**	**7,2**	**7,0**	**6,8**	**-2,0**	**0,5**	**-0,5**
		0,3	**0,5**	**0,5**	**0,6**	**0,5**	**0,4**	**0,3**	**0,3**	**-**	**2,7**	**-2,8**
0,65	**0,64**	**0,57**	**0,56**	**0,60**	**0,63**	**0,64**	**0,64**	**0,62**	**0,61**	**-1,3**	**1,2**	**-0,2**
9839	**9463**	**8528**	**7782**	**8096**	**8214**	**8065**	**7886**	**7759**	**7586**	**-1,9**	**0,5**	**-0,4**
684	683	606	374	83	76	62	51	40	32	-5,8	-14,8	-4,2
4547	3736	3293	2572	2872	2750	2544	2395	2208	2093	-3,7	0,7	-1,4
2370	2632	2082	2275	2193	2047	2029	1980	1952	1878	-1,5	-1,0	-0,4
0	0	0	0	0	0	0	0	0	0	-	-	-
1252	1262	1281	1323	1403	1546	1550	1505	1518	1454	0,5	1,6	-0,3
605	785	554	417	624	624	622	624	628	628	-6,1	4,1	0,0
1	12	68	135	281	321	407	423	446	503	27,4	9,1	2,3
2	5	15	22	45	70	136	196	220	236	15,3	12,6	6,2
0	7	23	87	116	300	324	369	391	402	29,0	13,2	1,5
0	0	22	63	53	52	49	59	103	103	-	-2,0	3,5
379	341	584	515	427	427	340	285	254	257	4,2	-1,9	-2,5
7152	**7114**	**6511**	**5950**	**6498**	**6513**	**6394**	**6212**	**5971**	**5823**	**-1,8**	**0,9**	**-0,6**
1565	1367	1090	1028	1069	1002	962	983	992	1012	-2,8	-0,3	0,0
908	753	570	547	578	528	505	516	528	536	-3,1	-0,4	0,1
656	614	520	481	491	474	458	467	464	476	-2,4	-0,1	0,0
2815	2756	2430	2290	2362	2437	2413	2316	2198	2105	-1,8	0,6	-0,7
935	1021	993	949	1122	1095	1110	1083	1082	1092	-0,7	1,4	0,0
1837	1971	1999	1682	1946	1979	1909	1830	1699	1615	-1,6	1,6	-1,0
146	151	81	72	79	72	62	51	40	32	-7,1	-0,1	-3,9
3023	2804	2638	2133	2294	2176	1989	1839	1664	1558	-2,7	0,2	-1,7
1236	1288	976	1006	1117	1097	1085	1057	1043	1011	-2,4	0,9	-0,4
1240	1364	1312	1279	1416	1456	1524	1566	1600	1657	-0,6	1,3	0,6
257	245	239	220	248	246	242	233	214	207	-1,1	1,1	-0,9
1250	1263	1264	1240	1344	1465	1491	1464	1408	1354	-0,2	1,7	-0,4
0	0	0	0	0	0	1	2	3	3	-	53,8	16,3
675	**596**	**530**	**511**	**526**	**534**	**541**	**560**	**572**	**581**	**-1,5**	**0,4**	**0,4**

14

Croatia:Reference Scenario 2020 (REF2020)

Total transformation input (ktoe)
Transformation inputs into Thermal Power Generation and District heating
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Nuclear
Hydro, solar, wind and other renewables
Biomass & Waste [6]
Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Transformation inputs to other transformations
Transformation inputs into synthetic fuels processes
Hydrogen
Electricity

Total transformation output (ktoe)
Transformation output of Thermal Power Generation and District heating
Electricity
Heat
Transformation outputs from other transformations
Transformation outputs of synthetic fuels processes
Hydrogen
Synthetic hydrocarbons

Energy Branch Consumption (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Biomass & Waste [6] and Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Heat

SECURITY OF SUPPLY
Primary Production (incl. recovery of products) (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Nuclear
Renewable energy sources
Net Imports (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Electricity
Biomass
Hydrogen

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
7876	**6783**	**5426**	**4638**	**4720**	**4869**	**4942**	**4935**	**4874**	**4835**	**-3,7**	**0,5**	**0,0**
2233	**2199**	**1807**	**1785**	**1664**	**1811**	**1958**	**2049**	**2184**	**2230**	**-2,1**	**0,1**	**1,0**
537	532	524	302	4	4	0	0	0	0	-5,5	-34,9	-100,0
523	170	95	24	15	9	9	9	9	4	-17,7	-9,7	-4,3
549	681	501	697	500	386	386	378	362	320	0,2	-5,7	-0,9
0	0	0	0	0	0	0	0	0	0	-	-	-
606	797	627	558	933	996	1143	1217	1269	1342	-3,5	6,0	1,5
4	7	40	120	104	158	161	182	269	269	33,3	2,8	2,7
0	0	0	49	83	236	236	236	236	236	-	16,9	0,0
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
13	13	20	35	24	22	24	27	41	59	10,4	-4,5	5,0
5643	**4584**	**3619**	**2853**	**3056**	**3058**	**2982**	**2883**	**2685**	**2598**	**-4,6**	**0,7**	**-0,8**
0	**0**	**0**	**0**	**0**	**0**	**2**	**3**	**5**	**6**	**-**	**61,0**	**15,5**
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	2	3	5	6	-	61,0	15,5
7042	**6115**	**4881**	**4096**	**4512**	**4564**	**4637**	**4637**	**4433**	**4404**	**-3,9**	**1,1**	**-0,2**
1429	**1564**	**1233**	**1207**	**1453**	**1489**	**1630**	**1720**	**1714**	**1786**	**-2,6**	**2,1**	**0,9**
1132	1281	974	1007	1208	1239	1392	1487	1560	1628	-2,4	2,1	1,4
297	282	259	201	245	251	238	234	154	158	-3,4	2,2	-2,3
5613	**4551**	**3648**	**2889**	**3059**	**3074**	**3006**	**2914**	**2715**	**2614**	**-4,4**	**0,6**	**-0,8**
0	**0**	**0**	**0**	**0**	**0**	**1**	**3**	**4**	**5**	**-**	**61,4**	**15,6**
0	0	0	0	0	0	1	3	4	5	-	61,4	15,6
0	0	0	0	0	0	0	0	0	0	-	-	-
793	**719**	**600**	**488**	**477**	**477**	**439**	**424**	**392**	**374**	**-3,8**	**-0,2**	**-1,2**
0	0	0	0	0	0	0	0	0	0	-	-	-
563	442	356	265	271	270	246	239	218	196	-5,0	0,2	-1,6
155	205	169	150	150	145	137	117	115	108	-3,1	-0,4	-1,4
0	0	1	2	2	4	6	5	6	6	-	8,5	1,6
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
75	72	71	63	44	41	40	39	40	38	-1,2	-4,2	-0,4
0	0	2	7	10	17	10	24	14	25	-	8,4	2,1
4759	**5153**	**4369**	**4564**	**5058**	**5258**	**5430**	**5451**	**5199**	**5106**	**-1,2**	**1,4**	**-0,1**
0	0	0	0	0	0	0	0	0	0	-	-	-
1034	765	701	431	455	421	372	339	292	269	-5,6	-0,2	-2,2
1865	2215	1471	1409	1326	1184	1046	939	899	858	-4,4	-1,7	-1,6
0	0	0	0	0	0	0	0	0	0	-	-	-
1860	2174	2196	2724	3277	3653	4011	4172	4007	3979	2,3	3,0	0,4
5174	**4426**	**4215**	**3218**	**3038**	**2956**	**2635**	**2435**	**2560**	**2479**	**-3,1**	**-0,8**	**-0,9**
624	700	624	374	83	76	62	51	40	32	-6,1	-14,8	-4,2
3609	3012	2702	2204	2470	2381	2221	2115	2018	1927	-3,1	0,8	-1,1
562	475	564	866	867	863	983	1041	1053	1020	6,2	0,0	0,8
379	341	584	515	427	427	340	285	254	257	4,2	-1,9	-2,5
0	-103	-259	-742	-808	-790	-971	-1055	-804	-756	21,8	0,6	-0,2
0	0	0	0	0	0	0	-1	-1	-1	-	7032,1	14,4

Croatia:Reference Scenario 2020 (REF2020)

Import Dependency (%) (10)	
ECONOMIC INDICATORS	
Total energy-related costs (in 000 M€15) [11]	
as % of GDP	
Energy cost indicators	
Energy expenditure in households (% of private consumption) [12]	
fuel cost	
capital cost	
Average Cost of Gross Electricity Generation (€'15/MWh)	
Average Price of Electricity in Final demand sectors (€'15/MWh) [13]	
Energy Intensity indicator	
Gross Available Energy/GDP (toe/M€15)	

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
52,6	**46,8**	**49,4**	**41,3**	**37,5**	**36,0**	**32,7**	**30,9**	**33,0**	**32,7**	**-**	**-**	**-**
6,0	**7,1**	**8,0**	**7,1**	**9,5**	**11,0**	**11,2**	**11,7**	**11,7**	**11,7**	**0,0**	**4,4**	**0,3**
13,7	15,8	18,0	15,6	18,6	20,8	20,2	19,7	18,3	17,2	-0,2	2,9	-0,9
8,4	12,0	12,6	11,0	12,3	13,0	12,1	12,0	11,0	9,9	-0,8	1,7	-1,3
6,8	8,1	8,4	6,7	6,8	7,5	7,1	6,6	6,0	5,4	-1,8	1,0	-1,6
1,6	3,8	4,2	4,3	5,5	5,5	5,0	5,4	5,0	4,5	1,1	2,6	-1,1
74,8	67,0	60,1	63,3	58,7	62,7	62,5	61,8	64,4	63,6	-0,6	-0,1	0,1
83,7	109,0	116,0	115,2	125,1	132,6	128,3	129,6	131,7	131,9	0,6	1,4	0,0
224	210	191	170	159	156	146	132	121	111	-2,1	-0,9	-1,7

Croatia:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe) (1)
By transport mean
Buses and coaches

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	12354	**13999**	**11158**	**11545**	**13868**	**14222**	**15992**	**17090**	**17822**	**18394**	**-1,9**	**2,1**	**1,3**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	6357	8501	7389	6880	11244	12355	14094	15037	15764	16625	-2,1	6,0	1,5
	14	33	101	338	297	501	533	613	742	751	26,2	4,0	2,0
	6333	8329	6439	4844	7252	7257	7237	7255	7304	7304	-5,3	4,1	0,0
	3106	3903	3186	2318	3608	3603	3583	3600	3597	3601	-5,1	4,5	0,0
	3227	4426	3252	2525	3644	3654	3654	3654	3708	3703	-5,5	3,8	0,1
	10	139	792	1566	3264	3735	4737	4918	5192	5851	27,4	9,1	2,3
	10	139	792	1566	3264	3735	4737	4918	5192	5181	27,4	9,1	1,6
	0	0	0	0	0	0	0	0	0	670	-	-	-
	0	0	57	75	334	588	1313	1978	2252	2445	-	22,8	7,4
	0	0	0	57	97	274	274	274	274	274	-	17,0	0,0
	5997	5498	3769	4664	2624	1867	1898	2053	2058	1769	-1,6	-8,7	-0,3
	2328	2385	1704	957	8	7	0	0	0	0	-8,7	-38,6	-100,0
	1855	560	399	84	30	24	31	31	29	16	-17,2	-11,7	-2,2
	1814	2553	1667	3622	2585	1835	1867	2022	2029	1754	3,6	-6,6	-0,2
	0	0	0	0	0	0	0	0	0	0	-	-	-
	3945	**4216**	**4939**	**4732**	**5960**	**6273**	**7050**	**7487**	**7421**	**7889**	**1,2**	**2,9**	**1,2**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	2075	2235	2827	3218	4331	4941	5977	6616	6951	7438	3,7	4,4	2,1
	9	15	153	175	261	420	417	405	399	451	27,7	9,1	0,4
	2060	2141	2208	2208	2267	2270	2270	2270	2270	2269	0,3	0,3	0,0
	1141	1222	1281	1281	1291	1291	1291	1291	1291	1292	0,5	0,1	0,0
	919	919	927	927	976	979	979	979	979	978	0,1	0,5	0,0
	6	79	418	762	1506	1713	2150	2229	2346	2621	25,4	8,4	2,2
	6	79	418	762	1506	1713	2150	2229	2346	2334	25,4	8,4	1,6
	0	0	0	0	0	0	0	0	0	287	-	-	-
	0	0	48	63	279	490	1092	1663	1889	2049	-	22,8	7,4
	0	0	0	10	17	48	48	48	48	48	-	17,0	0,0
	1870	1981	2113	1514	1630	1333	1073	871	470	451	-2,6	-1,3	-5,3
	311	311	311	195	195	195	193	193	0	0	-4,6	0,0	-100,0
	646	649	643	599	394	347	105	12	12	7	-0,8	-5,3	-17,7
	913	1021	1158	720	1041	791	775	667	458	444	-3,4	0,9	-2,8
	0	0	0	0	0	0	0	0	0	0	-	-	-
	30	**33**	**34**	**29**	**38**	**42**	**44**	**46**	**48**	**49**	**-1,4**	**3,9**	**0,8**
	3	3	3	3	4	4	4	4	4	4	-1,1	3,7	0,3
	24	26	26	23	29	32	33	35	36	37	-1,0	3,2	0,7
	0	0	0	0	0	0	0	0	0	0	2,9	2,3	0,6
	2	2	2	1	1	1	1	1	1	2	-9,8	5,5	0,5
	1	2	2	1	4	4	5	6	6	6	-0,2	11,6	1,7
	0	0	0	0	0	0	0	0	0	0	-3,8	7,8	0,7
	14	**12**	**12**	**13**	**16**	**19**	**20**	**21**	**22**	**22**	**0,8**	**3,5**	**0,9**
	11	8	9	10	12	14	15	16	17	17	1,4	4,0	0,9
	3	3	2	3	3	3	3	3	4	4	-0,4	2,4	0,8
	0	1	1	1	1	1	1	1	2	2	-1,1	2,2	1,2
	1835	**1969**	**1996**	**1680**	**1944**	**1977**	**1907**	**1828**	**1697**	**1613**	**-1,6**	**1,6**	**-1,0**
	43	64	64	54	73	75	74	75	74	73	-1,7	3,3	-0,1

Croatia:Reference Scenario 2020 (REF2020)

Passenger cars
Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2, 3]
Freight transport[3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%)[4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula)[5]
Energy intensity indicators
Passenger transport (toe/Mpkm) [2, 3]
Freight transport (toe/Mtkm)[3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$) [6]
of which ETS sectors (stationary installations) GHG emissions[7]
International bunkers emissions ($MtCO_2$) [8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport [9]
Other CO_2 Emissions (non land-use related) ($MtCO_2$)
Non-CO_2 GHG emissions ($MtCO_2eq$) (6),(10)
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport [9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
1091	1341	1434	1112	1275	1247	1191	1108	980	893	-1,9	1,2	-1,7
32	40	8	8	8	9	9	9	9	9	-15,3	1,5	0,0
573	427	401	432	494	549	533	535	530	534	0,1	2,4	-0,1
52	50	37	32	38	40	40	40	39	37	-4,2	2,0	-0,4
13	11	11	6	12	11	11	11	11	11	-6,2	7,5	-0,1
33	38	42	37	43	46	48	52	55	56	-0,1	2,2	1,0
1945	**2075**	**2117**	**1750**	**2114**	**2154**	**2094**	**2021**	**1895**	**1813**	**-1,7**	**2,1**	**-0,9**
1281	1568	1647	1253	1547	1528	1482	1405	1281	1196	-2,2	2,0	-1,2
665	506	469	497	567	625	612	617	614	617	-0,2	2,3	-0,1
111	**105**	**121**	**69**	**170**	**177**	**187**	**193**	**198**	**201**	**-4,1**	**9,8**	**0,6**
86	99	117	66	165	173	182	188	193	196	-3,9	10,1	0,6
25	7	4	3	5	5	5	5	5	5	-6,7	3,0	0,5
0,0	0,0	0,0	0,1	0,1	1,2	2,8	4,4	6,7	8,5	-	33,4	10,1
0,0	0,1	1,2	7,4	6,3	6,8	7,3	6,9	7,0	7,1	49,8	-0,8	0,2
		0,0	0,6	1,0	3,6	5,4	7,0	9,8	10,0	-	20,7	5,2
	30,4	32,7	33,1	27,9	25,4	23,2	20,8	18,3	16,6	0,8	-2,6	-2,1
	7,3	7,3	8,5	7,3	7,7	7,2	7,0	6,7	6,7	1,6	-1,0	-0,7
30,3	**28,5**	**24,4**	**20,9**	**19,9**	**18,6**	**17,2**	**16,5**	**15,5**	**14,7**	**-3,0**	**-1,2**	**-1,1**
12,4	10,4	8,4	7,0	5,5	4,9	4,5	4,3	4,2	4,0	-3,9	-3,5	-1,0
0,3	**0,3**	**0,4**	**0,2**	**0,5**	**0,5**	**0,6**	**0,6**	**0,6**	**0,6**	**-4,1**	**9,8**	**0,5**
0,3	0,3	0,3	0,2	0,5	0,5	0,5	0,6	0,6	0,6	-3,9	10,1	0,5
0,1	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-6,9	3,0	0,3
19,9	**18,3**	**15,8**	**13,3**	**12,4**	**11,7**	**10,9**	**10,2**	**9,4**	**8,8**	**-3,1**	**-1,3**	**-1,4**
5,1	4,3	3,5	2,9	1,2	0,9	0,9	0,9	0,9	0,8	-3,7	-10,6	-1,1
2,0	1,8	1,4	1,1	1,1	1,1	1,0	0,9	0,9	0,8	-4,8	0,0	-1,6
3,5	2,9	2,2	2,0	2,0	1,8	1,5	1,3	1,2	1,2	-3,4	-1,5	-2,0
2,4	2,1	1,5	1,4	1,4	1,4	1,4	1,2	1,2	1,1	-4,0	0,0	-1,2
1,5	1,4	1,2	1,2	1,3	1,1	1,0	1,0	0,9	0,9	-1,5	-1,0	-0,8
5,5	5,9	5,9	4,6	5,4	5,4	5,1	4,8	4,3	4,0	-2,3	1,5	-1,4
3,5	**2,8**	**2,3**	**2,3**	**2,4**	**2,3**	**2,1**	**2,1**	**2,0**	**2,0**	**-2,0**	**-0,1**	**-0,6**
7,0	**7,5**	**6,5**	**5,5**	**5,2**	**4,7**	**4,3**	**4,3**	**4,2**	**4,0**	**-2,9**	**-1,6**	**-0,8**
-0,1	**-0,1**	**-0,2**	**-0,2**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**13,8**	**-4,4**	**-1,0**
0,41	0,30	0,32	0,25	0,09	0,07	0,06	0,05	0,05	0,04	-1,9	-12,4	-2,4
1,79	1,72	1,66	1,56	1,55	1,48	1,40	1,34	1,29	1,24	-1,0	-0,5	-0,9
2,24	2,10	1,99	1,98	1,88	1,75	1,52	1,33	1,24	1,17	-0,6	-1,2	-2,0
0,85	0,77	0,61	0,61	0,60	0,58	0,56	0,54	0,53	0,52	-2,2	-0,6	-0,5
1,57	1,36	1,26	1,26	1,12	0,98	0,94	0,89	0,86	0,84	-0,8	-2,4	-0,8
2,98	2,98	2,96	2,76	2,78	2,73	2,67	2,63	2,56	2,50	-0,7	-0,1	-0,4

Hungary:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries [7]
Other industrial sectors
Residential
Tertiary [8]
Transport [9]
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
10,1	**10,0**	**9,9**	**9,8**	**9,7**	**9,6**	**9,5**	**9,4**	**9,4**	**9,3**	**-0,2**	**-0,2**	**-0,2**
102	**101**	**112**	**122**	**147**	**166**	**184**	**200**	**215**	**232**	**1,9**	**3,1**	**1,7**
5,2	4,2	4,5	4,4	4,0	3,8	3,5	3,3	3,1	3,0	0,3	-1,5	-1,2
32,1	30,5	30,5	29,3	29,7	29,4	28,8	28,3	27,9	27,5	-0,4	0,0	-0,3
62,7	65,3	65,0	66,3	66,3	66,8	67,7	68,4	69,0	69,5	0,2	0,1	0,2
76,0	**65,6**	**60,4**	**56,6**	**58,0**	**51,1**	**48,9**	**45,9**	**43,5**	**42,8**	**-1,5**	**-1,0**	**-0,9**
4,5	**8,6**	**14,9**	**14,1**	**16,9**	**21,3**	**24,6**	**27,0**	**28,6**	**29,8**	**5,0**	**4,2**	**1,7**
6,0	11,1	21,7	18,4	21,5	27,0	30,7	34,3	35,1	36,2	5,2	3,9	1,5
4,4	7,1	8,8	12,5	17,6	20,8	26,3	29,2	33,7	35,3	5,8	5,2	2,7
		5,0	8,4	9,7	15,2	19,3	20,3	22,4	24,1	-	6,0	2,3
18,4	**17,0**	**17,0**	**16,3**	**18,1**	**18,4**	**17,8**	**17,4**	**17,2**	**17,4**	**-0,4**	**1,2**	**-0,3**
26,4	**24,6**	**23,5**	**22,1**	**23,5**	**26,1**	**24,4**	**23,6**	**23,1**	**23,2**	**-1,1**	**1,7**	**-0,6**
		0,7	**1,0**	**0,8**	**1,1**	**0,7**	**0,5**	**0,3**	**0,3**	**-**	**1,5**	**-7,3**
0,69	**0,66**	**0,61**	**0,59**	**0,63**	**0,61**	**0,60**	**0,59**	**0,59**	**0,60**	**-1,2**	**0,3**	**-0,1**
28569	**26619**	**25366**	**24121**	**25950**	**29378**	**27978**	**27549**	**27197**	**27447**	**-1,0**	**2,0**	**-0,3**
3070	2703	2370	1580	725	760	608	436	392	361	-5,2	-7,1	-3,6
7454	6799	7047	6880	7544	7696	7440	7486	7456	7438	0,1	1,1	-0,2
12144	9852	7490	7703	9462	7491	7987	7395	6940	7116	-2,4	-0,3	-0,3
3616	3963	4131	4050	3942	8624	6693	6640	6522	6449	0,2	7,9	-1,4
1642	2690	2941	2463	2591	3127	3168	3120	3070	3185	-0,9	2,4	0,1
17	16	20	20	20	20	20	23	25	25	2,2	0,0	1,1
1	46	58	58	103	103	235	347	509	574	2,3	6,0	9,0
2	5	21	142	400	630	795	858	933	986	38,6	16,0	2,3
87	99	113	192	309	479	572	767	775	793	6,9	9,6	2,6
0	0	0	0	0	0	0	0	0	0	-65,2	-	-29,8
535	447	1176	1031	852	449	459	476	575	520	8,7	-8,0	0,7
18122	**16807**	**16862**	**16257**	**17930**	**18158**	**17651**	**17327**	**17139**	**17286**	**-0,3**	**1,1**	**-0,2**
3061	2532	3900	3855	4282	4914	4519	4378	4260	4394	4,3	2,5	-0,6
1957	1494	2127	2069	2359	2556	2115	2035	1995	2001	3,3	2,1	-1,2
1104	1038	1773	1786	1923	2358	2404	2343	2265	2392	5,6	2,8	0,1
6969	6649	5974	5779	6134	5869	5790	5678	5673	5714	-1,4	0,2	-0,1
4061	3537	2810	2461	2817	2713	2752	2684	2683	2703	-3,6	1,0	0,0
4031	4089	4178	4163	4696	4662	4591	4587	4523	4475	0,2	1,1	-0,2
463	237	176	152	158	97	61	36	25	20	-4,4	-4,4	-7,5
4629	4360	4959	4899	5100	4642	4243	4115	3988	3848	1,2	-0,5	-0,9
7759	6172	5382	5283	5935	5634	5135	4656	4528	4574	-1,5	0,6	-1,0
2781	2941	3120	3101	3455	3896	4097	4254	4375	4549	0,5	2,3	0,8
1308	1090	985	977	1078	1225	1373	1377	1330	1350	-1,1	2,3	0,5
1183	2006	2240	1845	2204	2663	2740	2883	2882	2926	-0,8	3,7	0,5
0	0	0	0	0	0	2	6	11	18	-	73,4	27,1
2170	**1974**	**1902**	**1982**	**2446**	**3243**	**3437**	**3649**	**3795**	**3963**	**0,0**	**5,0**	**1,0**

14

Hungary:Reference Scenario 2020 (REF2020)

Total transformation input (ktoe)
Transformation inputs into Thermal Power Generation and District heating
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Nuclear
Hydro, solar, wind and other renewables
Biomass & Waste [6]
Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Transformation inputs to other transformations
Transformation inputs into synthetic fuels processes
Hydrogen
Electricity
Total transformation output (ktoe)
Transformation output of Thermal Power Generation and District heating
Electricity
Heat
Transformation outputs from other transformations
Transformation outputs of synthetic fuels processes
Hydrogen
Synthetic hydrocarbons
Energy Branch Consumption (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Biomass & Waste [6] and Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Heat
SECURITY OF SUPPLY
Primary Production (incl. recovery of products) (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Nuclear
Renewable energy sources
Net Imports (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Electricity
Biomass
Hydrogen
Import Dependency (%) [10]

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
21696	**23041**	**19072**	**17758**	**18542**	**22961**	**22085**	**22694**	**25195**	**26735**	**-2,6**	**2,6**	**0,8**
9944	**9918**	**8493**	**7843**	**8038**	**11337**	**10664**	**10584**	**10407**	**10658**	**-2,3**	**3,8**	**-0,3**
2013	1684	1470	876	5	0	0	0	0	0	-6,3	-100,0	-
168	145	47	0	0	0	0	0	0	0	-100,0	-	-
3581	3276	1946	1899	2890	1077	2003	1807	1458	1564	-5,3	-5,5	1,9
3616	3963	4131	4050	3942	8624	6693	6640	6522	6449	0,2	7,9	-1,4
18	62	88	206	507	731	1020	1191	1424	1539	12,7	13,5	3,8
541	782	759	716	617	754	785	730	694	773	-0,9	0,5	0,1
6	6	52	95	78	152	156	127	109	100	32,1	4,9	-2,1
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	6	89	200	234	-	0,0	40,6
11752	**13123**	**10579**	**9916**	**10504**	**11623**	**11419**	**12105**	**14779**	**16063**	**-2,8**	**1,6**	**1,6**
0	**0**	**0**	**0**	**0**	**0**	**2**	**5**	**9**	**14**	**-**	**69,3**	**24,8**
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	2	5	9	14	-	69,3	24,8
15670	**17080**	**13814**	**13280**	**14425**	**16522**	**16699**	**17675**	**20431**	**22006**	**-2,5**	**2,2**	**1,4**
4593	**4479**	**3657**	**3725**	**4317**	**5382**	**5706**	**5919**	**5985**	**6263**	**-1,8**	**3,7**	**0,8**
3074	3213	2552	2627	3116	4027	4197	4411	4531	4790	-2,0	4,4	0,9
1519	1266	1105	1098	1201	1354	1508	1508	1454	1472	-1,4	2,1	0,4
11077	**12601**	**10158**	**9556**	**10108**	**11141**	**10992**	**11752**	**14439**	**15733**	**-2,7**	**1,5**	**1,7**
0	**0**	**0**	**0**	**0**	**0**	**2**	**4**	**7**	**10**	**-**	**69,7**	**24,9**
0	0	0	0	0	0	2	4	7	10	-	69,7	24,9
0	0	0	0	0	0	0	0	0	0	-	-	-
1145	**1037**	**918**	**812**	**703**	**770**	**691**	**667**	**633**	**612**	**-2,4**	**-0,5**	**-1,1**
1	1	1	1	0	0	0	0	0	0	-4,2	-31,0	-2,2
254	317	294	282	267	256	223	225	210	205	-1,2	-1,0	-1,1
309	252	282	226	188	206	191	175	166	146	-1,1	-0,9	-1,7
0	0	13	14	16	20	22	20	19	21	-	3,6	0,0
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
490	392	290	247	192	251	219	212	205	206	-4,5	0,1	-1,0
90	75	39	42	40	38	36	35	34	34	-5,7	-1,0	-0,5
10948	**11706**	**11157**	**9869**	**6730**	**12507**	**11059**	**11437**	**12458**	**13444**	**-1,7**	**2,4**	**0,4**
1748	1593	1432	921	32	23	24	22	15	14	-5,3	-31,0	-2,2
1494	1084	867	687	324	229	0	0	0	0	-4,5	-10,4	-100,0
2340	2243	1369	1076	629	603	0	0	0	0	-7,1	-5,6	-100,0
3616	3963	4131	4050	3942	8624	6693	6640	6522	6449	0,2	7,9	-1,4
1749	2823	3358	3136	1804	3028	4342	4774	5922	6981	1,1	-0,3	4,3
17770	**15167**	**13687**	**14252**	**19220**	**16872**	**16919**	**16115**	**14744**	**14011**	**-0,6**	**1,7**	**-0,9**
1303	1132	891	660	694	737	585	414	378	347	-5,3	1,1	-3,7
6083	5799	6602	6193	7220	7467	7440	7486	7456	7438	0,7	1,9	0,0
9848	7754	5218	6627	8833	6888	7987	7395	6940	7116	-1,6	0,4	0,2
535	447	1176	1031	852	449	459	476	575	520	8,7	-8,0	0,7
0	35	-201	-260	1621	1331	448	341	-610	-1419	-	-	-
0	0	0	0	0	0	0	3	5	8	-	-	32,2
62,2	**57,0**	**54,0**	**59,1**	**74,1**	**57,4**	**60,5**	**58,5**	**54,2**	**51,0**	**-**	**-**	**-**

Hungary:Reference Scenario 2020 (REF2020)

ECONOMIC INDICATORS	
Total energy-related costs (in 000 M€15) [11]	
as % of GDP	
Energy cost indicators	
Energy expenditure in households (% of private consumption) [12]	
fuel cost	
capital cost	
Average Cost of Gross Electricity Generation (€'15/MWh)	
Average Price of Electricity in Final demand sectors (€'15/MWh) [13]	
Energy Intensity indicator	
Gross Available Energy/GDP (toe/M€15)	

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
16,5	**21,6**	**19,4**	**17,6**	**23,5**	**28,3**	**30,6**	**33,8**	**35,3**	**36,7**	**-2,0**	**4,9**	**1,3**
16,1	21,3	17,3	14,4	16,0	17,0	16,6	16,9	16,5	15,8	-3,8	1,7	-0,4
8,6	15,5	12,5	10,4	10,7	10,6	9,5	9,9	9,2	8,4	-3,9	0,2	-1,1
6,1	10,3	7,5	5,5	5,4	5,4	5,1	5,2	5,2	4,9	-6,0	-0,3	-0,5
2,5	5,2	5,0	4,9	5,3	5,3	4,3	4,7	4,0	3,6	-0,6	0,7	-1,9
60,4	67,4	67,0	68,6	61,7	76,9	81,8	90,1	90,2	91,4	0,2	1,2	0,9
106,6	131,8	99,9	97,9	103,8	113,1	115,4	127,1	131,0	132,0	-2,9	1,5	0,8
279	263	226	197	177	176	152	138	127	118	-2,8	-1,1	-2,0

Hungary:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe) [1]
By transport mean
Buses and coaches
Passenger cars

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
35756	**37371**	**29672**	**30548**	**36238**	**46828**	**48804**	**50685**	**50874**	**53506**	**-2,0**	**4,4**	**0,7**
13834	15761	15850	15541	15125	33091	25683	25480	25025	24745	-0,1	7,9	-1,4
1942	3172	3952	5443	8322	11111	14486	16575	19450	21064	5,5	7,4	3,2
1730	2449	2924	3020	2439	2883	2902	2989	3090	3411	2,1	-0,5	0,8
202	188	235	233	233	233	233	273	291	291	2,2	0,0	1,1
0	0	0	0	0	0	0	0	0	0	-	-	-
202	188	235	233	233	233	233	273	291	291	2,2	0,0	1,1
10	534	671	671	1200	1200	2729	4040	5916	6669	2,3	6,0	9,0
10	534	671	671	1200	1200	2729	4040	5916	6669	2,3	6,0	9,0
0	0	0	0	0	0	0	0	0	0	-	-	-
0	1	123	1491	4422	6767	8593	9246	10126	10664	107,7	16,3	2,3
0	0	0	28	28	27	28	28	27	28	-	0,0	0,0
19980	18438	9869	9564	12790	2626	8636	8630	6399	7697	-6,4	-12,1	5,5
7023	6234	5900	3502	0	0	0	0	0	0	-5,6	-100,0	-
455	490	137	0	0	0	0	0	0	0	-100,0	-	-
12502	11714	3832	6062	12790	2626	8636	8630	6399	7697	-6,4	-8,0	5,5
0	0	0	0	0	0	0	0	0	0	-	-	-
8297	**8292**	**8247**	**9307**	**10638**	**14764**	**16245**	**16870**	**17472**	**18266**	**1,2**	**4,7**	**1,1**
1920	1920	1960	1960	1960	4300	3340	3510	3510	3510	0,2	8,2	-1,0
203	555	1082	2474	5287	7709	9901	11083	12685	13437	16,1	12,0	2,8
137	207	528	611	530	813	630	608	550	479	11,4	2,9	-2,6
49	53	57	57	57	57	57	67	71	71	0,7	0,0	1,1
0	0	0	0	0	0	0	0	0	0	-	-	-
49	53	57	57	57	57	57	67	71	71	0,7	0,0	1,1
17	293	329	329	578	578	1295	1908	2781	3132	1,2	5,8	8,8
17	293	329	329	578	578	1295	1908	2781	3132	1,2	5,8	8,8
0	0	0	0	0	0	0	0	0	0	-	-	-
0	2	168	1455	4100	6238	7896	8478	9261	9733	93,3	15,7	2,2
0	0	0	22	22	22	22	22	22	22	-	0,0	0,0
6174	5817	5205	4872	3392	2755	3005	2277	1277	1320	-1,8	-5,5	-3,6
1380	1155	1137	1073	11	0	0	0	0	0	-0,7	-100,0	-
176	91	91	11	11	5	5	4	0	0	-19,2	-7,3	-100,0
4617	4570	3977	3788	3370	2750	3000	2273	1277	1320	-1,9	-3,2	-3,6
0	0	0	0	0	0	0	0	0	0	-	-	-
83	**83**	**88**	**80**	**104**	**117**	**126**	**135**	**141**	**147**	**-0,4**	**3,8**	**1,2**
18	16	18	14	18	20	21	22	22	22	-1,9	4,0	0,5
49	53	55	56	67	75	82	88	92	95	0,6	3,0	1,2
1	1	1	1	2	2	2	2	2	2	0,4	2,4	1,1
12	10	11	7	11	13	15	16	17	19	-3,7	6,6	1,7
3	3	4	2	5	6	7	7	8	9	-2,9	10,9	1,8
0	0	0	0	0	0	0	0	0	0	-	-	-
35	**34**	**35**	**42**	**51**	**58**	**63**	**68**	**71**	**75**	**2,2**	**3,3**	**1,3**
24	23	23	27	31	35	37	39	41	43	1,7	2,8	1,0
9	9	10	13	17	20	24	26	28	29	4,3	4,4	1,8
2	2	2	2	2	2	3	3	3	3	-2,6	2,5	1,1
4031	**4062**	**4149**	**4134**	**4662**	**4632**	**4561**	**4558**	**4496**	**4447**	**0,2**	**1,1**	**-0,2**
467	427	447	327	415	410	406	413	414	409	-2,6	2,3	0,0
2119	2135	2144	2118	2376	2255	2163	2135	2064	1978	-0,1	0,6	-0,7

Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2, 3]
Freight transport [3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%) [4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula) [5]
Energy intensity indicators
Passenger transport (toe/Mpkm) [2, 3]
Freight transport (toe/Mtkm) [3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$)[6]
of which ETS sectors (stationary installations) GHG emissions [7]
International bunkers emissions ($MtCO_2$) [8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport[9]
Other CO_2 Emissions (non land-use related) ($MtCO_2$)
Non-CO_2 GHG emissions ($MtCO_2eq$) [6,10]
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport [9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
33	34	33	29	33	35	36	38	39	39	-1,5	1,8	0,6
1256	1314	1377	1530	1659	1731	1734	1736	1737	1773	1,5	1,2	0,1
154	150	142	124	174	195	215	229	236	241	-1,9	4,6	1,1
3	0	0	0	0	0	0	0	0	0	-	-	-
1	1	6	5	5	6	6	7	7	7	16,5	2,2	0,8
4292	**4292**	**4323**	**4234**	**4895**	**4894**	**4844**	**4848**	**4793**	**4757**	**-0,1**	**1,5**	**-0,1**
2946	2880	2880	2626	3140	3055	2991	2986	2929	2856	-0,9	1,5	-0,3
1346	1412	1443	1608	1755	1839	1853	1862	1864	1901	1,3	1,3	0,2
261	**230**	**175**	**100**	**233**	**262**	**283**	**289**	**298**	**310**	**-8,0**	**10,1**	**0,8**
261	230	175	100	233	262	283	289	298	310	-8,0	10,1	0,8
0	0	0	0	0	0	0	0	0	0	-	-	-
0,0	0,0	0,0	0,0	0,3	1,9	2,7	3,2	4,0	4,9	-	45,5	4,9
0,1	4,2	4,2	5,6	6,3	9,2	9,5	9,2	9,3	9,3	3,0	5,1	0,0
		0,4	1,6	2,0	7,0	9,6	10,6	11,3	11,2	-	16,3	2,4
	33,1	31,1	31,8	28,5	24,6	22,2	20,7	19,4	18,0	-0,4	-2,5	-1,5
	41,8	41,0	38,4	34,7	31,8	29,3	27,4	26,1	25,4	-0,8	-1,9	-1,1
75,7	**65,3**	**60,1**	**56,5**	**57,6**	**50,8**	**48,5**	**45,5**	**43,1**	**42,4**	**-1,4**	**-1,1**	**-0,9**
29,4	23,0	19,7	16,6	16,1	12,9	13,2	11,8	10,6	10,8	-3,2	-2,5	-0,9
0,8	**0,7**	**0,5**	**0,3**	**0,7**	**0,8**	**0,8**	**0,9**	**0,9**	**0,9**	**-8,0**	**10,1**	**0,7**
0,8	0,7	0,5	0,3	0,7	0,8	0,8	0,9	0,9	0,9	-8,0	10,1	0,7
0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-	-	-
54,6	**47,3**	**42,7**	**39,1**	**39,8**	**33,7**	**32,7**	**30,1**	**28,4**	**28,3**	**-1,9**	**-1,5**	**-0,9**
18,3	16,4	12,0	9,0	7,9	4,1	6,0	5,2	4,4	4,6	-5,8	-7,7	0,6
1,9	1,9	1,9	1,7	1,4	1,4	1,3	1,2	1,1	1,1	-1,0	-2,1	-1,3
5,1	3,6	5,8	5,8	6,3	6,4	4,9	4,3	4,0	4,0	4,8	0,9	-2,3
10,7	8,6	6,7	7,2	7,5	6,5	5,7	4,9	4,8	4,8	-1,8	-0,9	-1,6
6,7	5,2	4,5	3,7	3,8	3,2	3,2	2,8	2,7	2,7	-3,3	-1,5	-0,9
11,9	11,5	11,8	11,6	12,9	12,1	11,7	11,7	11,4	11,1	0,1	0,4	-0,4
5,1	**4,1**	**4,0**	**4,1**	**5,1**	**5,8**	**5,0**	**4,8**	**4,7**	**4,7**	**-0,1**	**3,5**	**-1,1**
15,0	**13,2**	**13,5**	**13,3**	**12,7**	**11,3**	**10,8**	**10,4**	**9,9**	**9,4**	**0,1**	**-1,7**	**-0,9**
0,9	**0,7**	**-0,1**	**0,0**	**0,0**	**0,1**	**0,0**	**0,1**	**0,1**	**0,1**	**-**	**-**	**0,4**
0,51	0,44	0,41	0,30	0,22	0,09	0,12	0,10	0,09	0,09	-3,9	-11,6	0,0
1,90	1,73	1,71	1,74	1,70	1,55	1,44	1,37	1,34	1,31	0,1	-1,1	-0,9
1,67	1,43	1,48	1,50	1,48	1,29	1,07	0,98	0,94	0,91	0,5	-1,5	-1,7
1,54	1,30	1,13	1,24	1,23	1,11	0,99	0,87	0,84	0,84	-0,5	-1,1	-1,4
1,65	1,48	1,59	1,51	1,36	1,18	1,15	1,05	1,02	0,99	0,2	-2,5	-0,9
2,95	2,82	2,83	2,80	2,74	2,60	2,56	2,55	2,52	2,49	-0,1	-0,7	-0,2

Romania:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries [7]
Other industrial sectors
Residential
Tertiary (8)
Transport (9)
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	21,4	**20,3**	**19,9**	**19,3**	**18,5**	**17,8**	**17,2**	**16,6**	**16,0**	**15,5**	**-0,5**	**-0,8**	**-0,7**
	120	**138**	**160**	**183**	**228**	**265**	**295**	**314**	**331**	**349**	**2,8**	**3,8**	**1,4**
	7,0	4,8	4,8	5,6	4,7	4,2	3,8	3,6	3,4	3,3	1,6	-3,0	-1,2
	34,7	38,3	33,1	32,7	32,3	31,9	31,2	30,7	30,3	29,8	-1,6	-0,2	-0,3
	58,3	56,9	62,1	61,7	63,0	63,9	65,1	65,7	66,3	66,9	0,8	0,4	0,2
	155,4	**126,9**	**118,8**	**107,4**	**112,9**	**105,5**	**97,2**	**90,4**	**84,4**	**78,4**	**-1,7**	**-0,2**	**-1,5**
	17,6	**23,3**	**25,1**	**26,9**	**26,6**	**30,9**	**33,7**	**38,0**	**41,0**	**44,5**	**1,4**	**1,4**	**1,8**
	17,9	27,4	26,4	26,6	26,3	33,0	35,6	38,3	40,4	43,3	-0,3	2,2	1,4
	28,8	30,4	43,4	44,7	48,0	49,3	52,8	63,8	67,9	73,7	3,9	1,0	2,0
			5,0	8,3	10,2	14,5	20,3	25,7	33,3	39,3	-	5,7	5,1
	23,5	**22,1**	**21,5**	**21,1**	**24,7**	**25,3**	**24,8**	**23,9**	**22,9**	**22,2**	**-0,5**	**1,8**	**-0,6**
	36,0	**33,0**	**30,7**	**28,1**	**31,1**	**33,2**	**32,2**	**30,8**	**29,6**	**28,3**	**-1,6**	**1,7**	**-0,8**
			0,4	**0,8**	**0,6**	**0,7**	**0,5**	**0,5**	**0,4**	**0,4**	**-**	**-1,3**	**-2,3**
	0,37	**0,40**	**0,37**	**0,41**	**0,41**	**0,43**	**0,44**	**0,44**	**0,45**	**0,45**	**0,3**	**0,4**	**0,2**
	38636	**35044**	**31843**	**29258**	**32343**	**34828**	**33907**	**32550**	**31380**	**30089**	**-1,8**	**1,8**	**-0,7**
	8758	6960	5895	3657	2864	2691	1805	794	717	521	-6,2	-3,0	-7,9
	9746	8677	8674	7447	8879	8981	8297	7922	7254	6709	-1,5	1,9	-1,4
	13923	10788	8808	9128	10599	8892	9051	9049	8485	7684	-1,7	-0,3	-0,7
	1433	2923	3033	3033	3128	6221	6221	6130	6021	5611	0,4	7,4	-0,5
	3270	4132	3802	3958	4271	5026	5257	5216	5229	5347	-0,4	2,4	0,3
	1737	1710	1450	1346	1644	1643	1640	1645	1653	1653	-2,4	2,0	0,0
	0	26	607	629	866	1006	1006	1583	1824	2181	37,4	4,8	3,9
	0	0	171	173	299	587	900	1056	1097	1103	110,9	13,0	3,2
	18	23	31	39	44	163	134	149	162	180	5,4	15,4	0,5
	0	0	-45	0	0	0	0	0	0	0	255,7	163,1	-18,7
	-250	-196	-583	-153	-250	-383	-404	-994	-1062	-900	-2,4	9,6	4,4
	23402	**21950**	**21282**	**20982**	**24311**	**24902**	**24389**	**23512**	**22521**	**21817**	**-0,5**	**1,7**	**-0,7**
	8826	6414	6105	5892	6985	7247	7125	6857	6668	6531	-0,8	2,1	-0,5
	6025	4293	3940	3626	4064	4016	3837	3586	3409	3315	-1,7	1,0	-1,0
	2801	2120	2165	2266	2921	3231	3288	3271	3259	3217	0,7	3,6	0,0
	7991	8102	7371	7970	7614	7645	7580	7349	7159	6987	-0,2	-0,4	-0,4
	2443	2487	2469	2431	3192	3058	2952	2745	2591	2449	-0,2	2,3	-1,1
	4142	4948	5338	4689	6519	6951	6732	6560	6102	5849	-0,5	4,0	-0,9
	597	543	547	378	445	455	318	119	66	18	-3,6	1,9	-14,8
	6499	6025	6757	6051	7313	7196	6590	6158	5546	5133	0,0	1,7	-1,7
	7586	6120	5403	5861	6338	5704	5378	5228	5023	4877	-0,4	-0,3	-0,8
	3341	3553	3699	3735	4661	5353	5615	5705	5801	5905	0,5	3,7	0,5
	2135	1650	1273	1148	1421	1550	1588	1508	1431	1379	-3,6	3,0	-0,6
	3244	4060	3602	3809	4135	4644	4898	4786	4642	4482	-0,6	2,0	-0,2
	0	0	0	0	0	0	2	7	13	22	-	57,7	27,6
	2627	**2057**	**1125**	**1110**	**1153**	**1455**	**1546**	**1573**	**1599**	**1616**	**-6,0**	**2,7**	**0,5**

14

Romania:Reference Scenario 2020 (REF2020)

Total transformation input (ktoe)
Transformation inputs into Thermal Power Generation and District heating
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Nuclear
Hydro, solar, wind and other renewables
Biomass & Waste[6]
Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Transformation inputs to other transformations
Transformation inputs into synthetic fuels processes
Hydrogen
Electricity
Total transformation output (ktoe)
Transformation output of Thermal Power Generation and District heating
Electricity
Heat
Transformation outputs from other transformations
Transformation outputs of synthetic fuels processes
Hydrogen
Synthetic hydrocarbons
Energy Branch Consumption (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Biomass & Waste[6] and Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Heat
SECURITY OF SUPPLY
Primary Production (incl. recovery of products) (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Nuclear
Renewable energy sources
Net Imports (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Electricity
Biomass
Hydrogen
Import Dependency (%)[10]

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
	32432	**26278**	**26591**	**20557**	**24060**	**27592**	**28181**	**28667**	**29029**	**30245**	**-2,4**	**3,0**	**0,5**
	14334	**14119**	**13582**	**11056**	**11685**	**14183**	**14064**	**14196**	**14187**	**13613**	**-2,4**	**2,5**	**-0,2**
	6098	5931	4981	2965	1951	1830	1149	400	404	283	-6,7	-4,7	-8,9
	883	417	268	22	40	51	18	35	28	14	-25,4	8,7	-6,2
	4153	3007	2819	2655	3526	2306	2641	2777	2429	1765	-1,2	-1,4	-1,3
	1433	2923	3033	3033	3128	6221	6221	6130	6021	5611	0,4	7,4	-0,5
	1737	1736	2228	2147	2799	3212	3516	4245	4531	4894	2,1	4,1	2,1
	29	63	203	171	181	447	427	492	615	888	10,5	10,1	3,5
	1	1	9	16	3	29	7	8	11	10	31,0	6,0	-5,2
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	40	42	46	56	86	85	109	148	147	1,3	6,5	2,8
	18098	**12159**	**13009**	**9501**	**12375**	**13408**	**14113**	**14458**	**14820**	**16603**	**-2,4**	**3,5**	**1,1**
	0	**0**	**0**	**0**	**0**	**0**	**4**	**13**	**23**	**30**	**-**	**58,6**	**26,9**
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	4	13	23	30	-	58,6	26,9
	25815	**20467**	**20658**	**16476**	**20769**	**22873**	**23876**	**24705**	**25075**	**26684**	**-2,1**	**3,3**	**0,8**
	8017	**7456**	**7405**	**6799**	**8184**	**9218**	**9461**	**9944**	**9988**	**9778**	**-0,9**	**3,1**	**0,3**
	5109	5243	5689	5189	6253	7134	7334	7920	8067	7929	-0,1	3,2	0,5
	2909	2213	1716	1610	1932	2084	2127	2024	1921	1848	-3,1	2,6	-0,6
	17798	**13012**	**13252**	**9677**	**12585**	**13655**	**14412**	**14752**	**15071**	**16884**	**-2,9**	**3,5**	**1,1**
	0	**0**	**0**	**0**	**0**	**0**	**3**	**10**	**17**	**22**	**-**	**59,0**	**27,1**
	0	0	0	0	0	0	3	10	17	22	-	59,0	27,1
	0	0	0	0	0	0	0	0	0	0	-	-	-
	4278	**2897**	**2109**	**1941**	**2093**	**2142**	**2075**	**1984**	**1870**	**1746**	**-3,9**	**1,0**	**-1,0**
	6	1	0	0	0	0	0	0	0	0	-21,0	-4,3	-9,2
	1769	1205	826	748	853	841	776	758	647	548	-4,7	1,2	-2,1
	1314	766	437	366	452	496	531	509	487	482	-7,1	3,1	-0,1
	22	0	0	0	0	0	0	0	21	22	11,7	-18,2	47,0
	0	0	0	0	0	0	0	0	0	0	-	-	-
	0	0	0	0	0	0	0	0	0	0	-	-	-
	995	835	749	681	645	654	608	548	543	522	-2,0	-0,4	-1,1
	172	89	96	147	144	151	160	168	171	173	5,1	0,3	0,7
	27870	**27363**	**26189**	**23821**	**27417**	**31917**	**32212**	**32191**	**31903**	**30932**	**-1,4**	**3,0**	**-0,2**
	5677	5817	4440	2971	2000	1916	1217	387	368	276	-6,5	-4,3	-9,2
	5989	4265	4014	3282	4363	4917	5120	5211	4854	4294	-2,6	4,1	-0,7
	9701	8619	8678	8412	10848	10562	10876	10945	10811	10328	-0,2	2,3	-0,1
	1433	2923	3033	3033	3128	6221	6221	6130	6021	5611	0,4	7,4	-0,5
	5070	5739	6025	6124	7079	8301	8778	9518	9849	10423	0,7	3,1	1,1
	10621	**7521**	**5437**	**5436**	**4926**	**2911**	**1695**	**357**	**-527**	**-844**	**-3,2**	**-6,1**	**-**
	3025	1270	1255	687	864	775	588	407	348	244	-6,0	1,2	-5,6
	3656	4496	4566	4165	4516	4065	3177	2710	2400	2415	-0,8	-0,2	-2,6
	4190	1816	159	716	-249	-1671	-1825	-1896	-2326	-2645	-8,9	-	2,3
	-250	-196	-583	-153	-250	-383	-404	-994	-1062	-900	-2,4	9,6	4,4
	0	134	40	21	45	125	160	132	115	42	-17,0	19,5	-5,2
	0	0	0	0	0	0	-1	-2	-4	0	-	5278,7	-74,9
	27,5	**21,5**	**17,1**	**18,6**	**15,2**	**8,4**	**5,0**	**1,1**	**-1,7**	**-2,8**	**-**	**-**	**-**

Romania:Reference Scenario 2020 (REF2020)

ECONOMIC INDICATORS	
Total energy-related costs (in 000 M€15) [11]	
as % of GDP	
Energy cost indicators	
Energy expenditure in households (% of private consumption) [12]	
fuel cost	
capital cost	
Average Cost of Gross Electricity Generation (€'15/MWh)	
Average Price of Electricity in Final demand sectors (€'15/MWh) [13]	
Energy Intensity indicator	
Gross Available Energy/GDP (toe/M€15)	

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
18,4	**24,2**	**25,3**	**22,3**	**30,1**	**36,3**	**36,3**	**36,8**	**36,6**	**36,9**	**-0,8**	**5,0**	**0,1**
15,3	17,5	15,8	12,2	13,2	13,7	12,3	11,7	11,0	10,6	-3,5	1,2	-1,3
8,7	10,3	8,3	7,8	7,1	7,1	6,4	6,4	6,1	5,9	-2,7	-1,0	-0,9
6,5	6,0	5,0	3,9	3,6	3,6	3,4	3,3	3,3	3,1	-4,2	-0,8	-0,7
2,3	4,4	3,2	3,9	3,5	3,5	2,9	3,1	2,8	2,8	-1,0	-1,3	-1,1
72,1	70,1	50,4	52,3	53,2	62,5	64,3	61,3	67,9	66,3	-2,9	1,8	0,3
104,5	89,7	88,6	89,6	103,6	111,6	113,3	110,8	117,3	117,9	0,0	2,2	0,3
321	253	199	160	142	131	115	104	95	86	-4,5	-1,9	-2,1

Romania:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe) [1]
By transport mean
Buses and coaches
Passenger cars

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
59413	**60619**	**65780**	**59957**	**72238**	**82424**	**84722**	**91318**	**92611**	**91030**	**-0,1**	**3,2**	**0,5**
5555	11623	11638	11638	12002	23872	23872	23521	23104	21530	0,0	7,4	-0,5
20214	20300	26470	25699	33281	38461	42224	50873	54508	59385	2,4	4,1	2,2
7	111	564	730	750	1377	1426	1610	1954	2637	20,7	6,6	3,3
20207	19883	16862	15650	19120	19101	19074	19131	19219	19222	-2,4	2,0	0,0
12538	12327	9781	7519	9685	9666	9639	9662	9665	9668	-4,8	2,5	0,0
7669	7556	7082	8131	9435	9435	9435	9470	9554	9554	0,7	1,5	0,1
0	306	7062	7319	10067	11703	11703	18409	21210	25365	37,4	4,8	3,9
0	306	7062	7319	10067	11703	11703	18409	21210	25365	37,4	4,8	3,9
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	1982	2000	3344	6280	10021	11723	12124	12160	-	12,1	3,4
0	0	0	0	0	0	0	0	0	0	-	-	-
33644	28696	27672	22621	26955	20091	18626	16923	14998	10115	-2,4	-1,2	-3,4
21916	20681	17546	11996	8640	6817	3973	964	974	713	-5,3	-5,5	-10,7
1894	692	573	4	2	2	2	2	2	3	-39,6	-7,4	1,1
9834	7323	9554	10620	18313	13272	14651	15957	14022	9399	3,8	2,3	-1,7
0	0	0	0	0	0	0	0	0	0	-	-	-
19153	**20120**	**25014**	**21539**	**24154**	**28162**	**28315**	**29946**	**31410**	**32707**	**0,7**	**2,7**	**0,8**
672	1344	1414	1414	1414	2828	2828	2828	2828	2828	0,5	7,2	0,0
6294	6886	11630	11768	14124	16983	19556	23516	25018	26732	5,5	3,7	2,3
5	23	120	132	136	297	305	301	371	514	18,9	8,5	2,8
6289	6474	7009	7009	7290	7290	7290	7310	7310	7310	0,8	0,4	0,0
4750	4772	3385	3385	3666	3666	3666	3672	3672	3672	-3,4	0,8	0,0
1539	1702	3624	3624	3624	3624	3624	3638	3638	3638	7,9	0,0	0,0
0	389	3130	3244	4389	5069	5069	7846	9002	10572	23,6	4,6	3,7
0	389	3130	3244	4389	5069	5069	7846	9002	10572	23,6	4,6	3,7
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	1371	1383	2309	4328	6891	8059	8336	8336	-	12,1	3,3
0	0	0	0	0	0	0	0	0	0	-	-	-
12187	11890	11970	8358	8616	8350	5932	3601	3564	3147	-3,5	0,0	-4,8
7057	6643	6441	4521	3703	3601	2581	483	483	137	-3,8	-2,2	-15,1
1691	1759	1360	1132	771	676	115	115	115	115	-4,3	-5,0	-8,5
3439	3487	4169	2704	4142	4073	3236	3003	2966	2896	-2,5	4,2	-1,7
0	0	0	0	0	0	0	0	0	0	-	-	-
92	**113**	**130**	**104**	**164**	**195**	**211**	**223**	**229**	**236**	**-0,8**	**6,4**	**1,0**
12	16	17	11	19	20	21	22	22	22	-3,6	6,4	0,4
61	76	90	79	116	141	155	162	166	171	0,5	6,0	1,0
2	3	4	3	5	5	6	6	7	7	1,8	4,8	1,1
15	13	13	7	15	16	18	19	20	20	-5,7	8,9	1,0
3	6	7	4	10	11	12	14	14	15	-4,5	11,0	1,5
0	0	0	0	0	0	0	0	0	0	1,5	9,5	1,1
59	**43**	**44**	**45**	**59**	**71**	**77**	**84**	**88**	**92**	**0,4**	**4,7**	**1,3**
34	16	17	20	27	33	36	39	41	42	2,0	5,1	1,3
17	12	14	13	17	21	24	26	27	29	0,4	5,0	1,6
8	14	13	12	15	17	18	19	20	21	-1,9	3,6	1,0
4055	**4897**	**5335**	**4685**	**6516**	**6948**	**6729**	**6557**	**6100**	**5847**	**-0,4**	**4,0**	**-0,9**
250	336	459	276	456	480	480	494	490	483	-2,0	5,7	0,0
2190	3092	3525	3031	4284	4541	4322	4104	3632	3359	-0,2	4,1	-1,5

Romania:Reference Scenario 2020 (REF2020)

Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2,3]
Freight transport [3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%) [4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula) [5]
Energy intensity indicators
Passenger transport (toe/Mpkm) [2,3]
Freight transport (toe/Mtkm) [3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$) [6]
of which ETS sectors (stationary installations) GHG emissions [7]
International bunkers emissions ($MtCO_2$) [8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport [9]
Other CO_2 Emissions (non land-use related) ($MtCO_2$)
Non-CO_2 GHG emissions ($MtCO_2eq$) [6, 10]
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport [9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
62	78	87	78	102	117	124	129	130	132	-0,1	4,2	0,6
1340	996	983	1079	1356	1456	1429	1444	1462	1491	0,8	3,0	0,1
159	223	204	165	224	252	263	268	264	258	-3,0	4,3	0,1
12	111	33	20	49	53	59	62	64	67	-15,7	10,1	1,2
42	60	44	36	44	49	52	55	56	57	-4,9	3,2	0,8
4199	**5079**	**5619**	**4859**	**6915**	**7385**	**7212**	**7060**	**6613**	**6370**	**-0,4**	**4,3**	**-0,7**
2700	3865	4404	3590	5323	5662	5502	5327	4863	4596	-0,7	4,7	-1,0
1499	1214	1214	1269	1592	1723	1710	1733	1750	1774	0,4	3,1	0,1
144	**182**	**284**	**174**	**399**	**437**	**482**	**502**	**513**	**523**	**-0,5**	**9,7**	**0,9**
128	166	239	150	358	387	427	441	447	456	-1,0	9,9	0,8
16	16	45	23	41	50	56	61	65	67	4,0	7,9	1,5
0,0	0,0	0,0	0,0	0,1	1,3	2,7	3,4	5,3	6,9	-	40,0	8,5
0,0	2,0	3,7	6,7	6,9	7,8	8,9	8,4	8,5	8,4	13,0	1,5	0,4
		0,0	0,1	0,5	3,6	5,8	9,6	12,2	12,1	-	46,1	6,3
	29,1	29,5	31,3	28,4	25,2	22,4	20,3	18,0	16,4	0,7	-2,1	-2,1
	6,3	5,6	7,4	5,8	5,2	4,6	4,2	4,0	3,8	1,7	-3,6	-1,5
155,1	**126,6**	**118,4**	**107,1**	**112,2**	**104,7**	**96,3**	**89,5**	**83,5**	**77,5**	**-1,7**	**-0,2**	**-1,5**
71,6	54,4	42,4	31,2	31,3	27,6	23,7	19,7	17,9	15,2	-5,4	-1,2	-2,9
0,4	**0,5**	**0,9**	**0,5**	**1,2**	**1,3**	**1,4**	**1,5**	**1,5**	**1,5**	**-0,5**	**9,7**	**0,8**
0,4	0,5	0,7	0,4	1,1	1,2	1,3	1,3	1,3	1,3	-1,0	9,9	0,7
0,0	0,0	0,1	0,1	0,1	0,2	0,2	0,2	0,2	0,2	3,8	7,9	1,2
91,5	**75,5**	**69,6**	**57,1**	**61,2**	**56,1**	**50,1**	**44,3**	**40,4**	**36,3**	**-2,8**	**-0,2**	**-2,2**
39,0	33,6	28,9	19,0	17,0	13,7	11,5	8,7	7,9	5,9	-5,5	-3,2	-4,1
9,8	6,0	3,8	3,3	3,6	3,7	3,6	3,5	3,1	2,9	-5,9	1,3	-1,3
19,2	12,0	11,8	10,9	12,8	11,5	9,6	8,0	7,1	6,4	-1,0	0,5	-2,9
7,3	5,8	6,3	7,2	6,0	5,8	5,6	5,2	5,0	4,8	2,0	-2,1	-0,9
4,2	3,6	3,5	3,8	4,0	2,9	2,6	2,2	2,0	2,0	0,6	-2,7	-1,8
12,0	14,4	15,4	13,0	17,8	18,5	17,3	16,8	15,2	14,3	-1,0	3,6	-1,3
13,6	**10,2**	**8,3**	**8,3**	**9,4**	**9,6**	**8,5**	**8,1**	**7,5**	**7,2**	**-2,0**	**1,4**	**-1,4**
52,4	**42,3**	**40,6**	**41,3**	**40,8**	**38,1**	**36,6**	**35,8**	**34,4**	**32,8**	**-0,2**	**-0,8**	**-0,7**
-2,4	**-1,3**	**-0,2**	**0,4**	**0,8**	**1,0**	**1,1**	**1,3**	**1,2**	**1,2**	**-**	**10,0**	**1,1**
0,66	0,55	0,44	0,32	0,24	0,17	0,14	0,09	0,09	0,06	-5,4	-6,3	-4,6
1,83	1,63	1,73	1,66	1,67	1,55	1,44	1,37	1,31	1,26	0,2	-0,7	-1,0
2,17	1,88	1,93	1,85	1,83	1,59	1,34	1,16	1,07	0,98	-0,2	-1,5	-2,4
0,92	0,72	0,85	0,90	0,78	0,76	0,74	0,71	0,70	0,69	2,2	-1,7	-0,5
1,70	1,45	1,42	1,56	1,25	0,95	0,88	0,80	0,79	0,81	0,8	-4,9	-0,8
2,91	2,90	2,88	2,77	2,74	2,66	2,58	2,56	2,50	2,45	-0,5	-0,4	-0,4

14

Slovenia:Reference Scenario 2020 (REF2020)

MACROECONOMIC INPUTS
Population (in million)
GDP (in 000 M€15)
Share of Gross Value-Added: Agriculture (%)
Share of Gross Value-Added: Industry (%)
Share of Gross Value-Added: Services (%)
POLICY INDICATORS
Total GHG emissions incl. intra-EU bunkers, excl LULUCF (MtCO2eq) [1]
RES in Gross Final Energy Consumption (%)
RES-H&C share
RES-E share
RES-T share (based on REDII formula) [2]
Final Energy Consumption (Mtoe) [3]
Primary Energy Consumption (Mtoe) [4]
Annual renovation rate (as % of entire housing stock) [5]
Energy consumption per capita in residential sector (toe/capita)
ENERGY DEMAND
Gross Available Energy (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Nuclear
Biomass & Waste [6]
Hydro
Wind
Solar
Geothermal and ambient heat
Others
Electricity net imports
Final Energy Consumption (ktoe)
by sector
Industry
Energy intensive industries [7]
Other industrial sectors
Residential
Tertiary [8]
Transport [9]
by fuel
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Electricity
Heat (from CHP and District Heating)
Renewables
Hydrogen
Non-Energy Uses (ktoe)

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
2,0	**2,0**	**2,1**	**2,1**	**2,1**	**2,1**	**2,1**	**2,1**	**2,1**	**2,0**	**0,2**	**0,1**	**-0,2**
35	**38**	**39**	**42**	**51**	**57**	**63**	**67**	**71**	**75**	**0,9**	**3,2**	**1,4**
2,5	2,2	2,4	2,4	2,1	1,9	1,7	1,6	1,6	1,5	0,8	-2,6	-1,2
33,9	32,2	31,4	32,7	32,8	32,8	32,5	32,5	32,8	33,0	0,2	0,0	0,0
63,6	65,6	66,1	64,9	65,1	65,3	65,8	65,9	65,7	65,5	-0,1	0,1	0,0
20,7	**19,8**	**17,0**	**15,2**	**15,3**	**15,2**	**13,2**	**12,0**	**10,7**	**10,2**	**-2,6**	**0,0**	**-2,0**
15,9	**19,1**	**22,6**	**24,2**	**26,8**	**29,3**	**32,7**	**36,8**	**40,7**	**41,2**	**2,4**	**1,9**	**1,7**
19,0	25,5	35,4	34,7	38,5	41,9	45,8	47,7	51,0	51,0	3,1	1,9	1,0
28,7	32,2	32,7	34,7	35,4	35,7	37,8	44,1	48,5	47,7	0,8	0,3	1,5
		2,1	6,0	10,0	16,3	23,4	33,7	43,9	49,5	-	10,6	5,7
4,9	**5,0**	**4,7**	**4,2**	**4,9**	**4,8**	**4,6**	**4,4**	**4,3**	**4,2**	**-1,8**	**1,3**	**-0,6**
7,0	**7,0**	**6,5**	**5,9**	**6,4**	**6,5**	**6,1**	**6,0**	**4,8**	**4,2**	**-1,7**	**0,9**	**-2,1**
		0,4	**2,9**	**1,8**	**2,1**	**2,4**	**1,8**	**1,8**	**2,5**	**-**	**-3,1**	**0,9**
0,57	**0,61**	**0,55**	**0,49**	**0,55**	**0,54**	**0,52**	**0,51**	**0,50**	**0,48**	**-2,3**	**1,0**	**-0,5**
7346	**7235**	**6719**	**6182**	**6717**	**6839**	**6526**	**6406**	**5240**	**4675**	**-1,6**	**1,0**	**-1,9**
1538	1453	1068	882	680	636	353	282	40	61	-4,9	-3,2	-11,1
2602	2622	2362	1996	2096	1825	1527	1367	1229	642	-2,7	-0,9	-5,1
929	863	664	595	996	1394	1619	1681	1816	1742	-3,7	8,9	1,1
1518	1335	1472	1651	1518	1518	1518	1499	0	0	2,1	-0,8	-100,0
489	718	748	664	875	938	926	917	932	913	-0,8	3,5	-0,1
298	388	331	416	422	433	433	433	462	463	0,7	0,4	0,3
0	0	1	1	2	13	15	28	44	44	-	37,5	6,5
0	9	34	38	73	110	172	280	307	309	15,2	11,2	5,3
0	28	44	61	72	91	99	119	162	182	8,1	4,2	3,5
0	0	0	0	0	0	0	0	0	0	-	137,0	-
-28	-182	-4	-121	-18	-119	-135	-201	248	320	-4,0	-0,2	-
4872	**5009**	**4726**	**4248**	**4881**	**4834**	**4613**	**4482**	**4400**	**4340**	**-1,6**	**1,3**	**-0,5**
1646	1274	1228	1136	1273	1387	1358	1388	1397	1413	-1,1	2,0	0,1
1029	789	807	715	781	852	791	803	794	785	-1,0	1,8	-0,4
617	486	421	420	492	535	566	585	603	628	-1,4	2,4	0,8
1145	1255	1143	1029	1172	1153	1122	1094	1063	1015	-2,0	1,2	-0,6
619	702	574	517	627	605	623	618	648	672	-3,0	1,6	0,5
1463	1778	1781	1567	1809	1688	1510	1382	1292	1240	-1,3	0,7	-1,5
80	49	39	36	33	27	21	17	13	11	-2,9	-3,0	-4,2
2384	2440	2149	1821	1844	1559	1274	1077	938	835	-2,9	-1,5	-3,1
665	620	558	523	648	680	662	675	668	659	-1,7	2,7	-0,2
1096	1027	1100	1038	1259	1417	1498	1560	1614	1654	0,1	3,2	0,8
196	192	169	159	205	205	200	195	185	207	-1,9	2,6	0,0
452	681	712	671	892	945	952	939	953	933	-0,2	3,5	-0,1
0	0	0	0	0	1	6	18	28	39	-	62,2	18,1
311	**211**	**126**	**115**	**121**	**130**	**137**	**141**	**141**	**140**	**-5,9**	**1,2**	**0,4**

Slovenia:Reference Scenario 2020 (REF2020)

Total transformation input (ktoe)
Transformation inputs into Thermal Power Generation and District heating
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Nuclear
Hydro, solar, wind and other renewables
Biomass & Waste [6]
Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Transformation inputs to other transformations
Transformation inputs into synthetic fuels processes
Hydrogen
Electricity
Total transformation output (ktoe)
Transformation output of Thermal Power Generation and District heating
Electricity
Heat
Transformation outputs from other transformations
Transformation outputs of synthetic fuels processes
Hydrogen
Synthetic hydrocarbons
Energy Branch Consumption (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural and manufactured gases
Biomass & Waste [6] and Geothermal heat
Hydrogen
Synthetic hydrocarbons
Electricity
Heat
SECURITY OF SUPPLY
Primary Production (incl. recovery of products) (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Nuclear
Renewable energy sources
Net Imports (ktoe)
Solid fossil fuels
Crude oil and petroleum products
Natural gas
Electricity
Biomass
Hydrogen
Import Dependency (%) [10]

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
3413	**3407**	**3099**	**3168**	**3190**	**3670**	**3776**	**4054**	**2799**	**3019**	**-0,7**	**1,5**	**-1,0**
3413	**3366**	**3075**	**3099**	**3082**	**3482**	**3497**	**3605**	**2121**	**2102**	**-0,8**	**1,2**	**-2,5**
1412	1382	1018	840	641	602	324	257	19	41	-4,9	-3,3	-12,5
14	7	9	3	5	7	9	10	9	9	-8,8	9,1	1,5
134	158	99	63	326	671	908	956	1094	1030	-8,8	26,7	2,2
1518	1335	1472	1651	1518	1518	1518	1499	0	0	2,1	-0,8	-100,0
298	390	355	444	486	544	606	725	798	799	1,3	2,0	1,9
37	71	89	59	63	90	83	105	147	165	-1,9	4,4	3,1
0	2	2	3	4	6	3	3	3	5	4,0	7,9	-1,5
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	21	33	37	39	44	46	49	51	53	5,8	1,7	1,0
0	**41**	**23**	**69**	**108**	**187**	**273**	**430**	**650**	**879**	**5,3**	**10,4**	**8,0**
0	**0**	**0**	**0**	**0**	**1**	**6**	**19**	**29**	**38**	**-**	**57,2**	**17,9**
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	1	6	19	29	38	-	57,2	17,9
1537	**1684**	**1521**	**1658**	**1867**	**2221**	**2424**	**2694**	**2493**	**3216**	**-0,2**	**3,0**	**1,9**
1537	**1642**	**1498**	**1536**	**1706**	**1979**	**2065**	**2198**	**1771**	**1774**	**-0,7**	**2,6**	**-0,5**
1300	1413	1300	1351	1469	1743	1836	1977	1562	1541	-0,5	2,6	-0,6
237	229	198	185	237	236	229	221	209	233	-2,1	2,5	-0,1
0	**41**	**23**	**121**	**161**	**241**	**355**	**482**	**701**	**1413**	**11,3**	**7,1**	**9,2**
0	**0**	**0**	**0**	**0**	**1**	**4**	**14**	**22**	**29**	**-**	**57,6**	**18,0**
0	0	0	0	0	1	4	14	22	29	-	57,6	18,0
0	0	0	0	0	0	0	0	0	0	-	-	-
100	**107**	**94**	**88**	**85**	**108**	**100**	**97**	**66**	**66**	**-1,9**	**2,0**	**-2,4**
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
3	6	3	3	15	35	40	40	43	41	-5,4	26,2	0,8
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
0	0	0	0	0	0	0	0	0	0	-	-	-
94	99	89	83	68	71	58	56	23	25	-1,7	-1,5	-5,2
2	2	2	2	1	1	1	1	0	0	-1,5	-3,3	-12,3
3492	**3652**	**3455**	**3557**	**3528**	**3650**	**3455**	**3501**	**1904**	**1929**	**-0,3**	**0,3**	**-3,1**
1184	1196	862	814	620	579	313	249	22	42	-3,8	-3,3	-12,3
0	0	0	0	0	0	0	0	0	0	-	-	-
3	6	3	3	15	35	40	40	43	41	-5,4	26,2	0,8
1518	1335	1472	1651	1518	1518	1518	1499	0	0	2,1	-0,8	-100,0
787	1115	1119	1089	1375	1518	1583	1712	1840	1846	-0,2	3,4	1,0
3855	**3584**	**3253**	**2625**	**3189**	**3189**	**3073**	**2909**	**3343**	**2756**	**-3,1**	**2,0**	**-0,7**
323	280	204	69	61	57	40	33	19	18	-13,1	-1,9	-5,5
2634	2600	2353	1996	2096	1825	1527	1367	1229	642	-2,6	-0,9	-5,1
925	857	662	591	981	1358	1579	1641	1772	1700	-3,6	8,7	1,1
-28	-182	-4	-121	-18	-119	-135	-201	248	320	-4,0	-0,2	-
0	30	39	91	69	67	62	64	67	64	11,8	-2,9	-0,2
0	0	0	0	0	0	2	4	7	10	-	-	18,5
52,5	**49,5**	**48,4**	**42,5**	**47,5**	**46,6**	**47,1**	**45,4**	**63,8**	**59,0**	**-**	**-**	**-**

Slovenia:Reference Scenario 2020 (REF2020)

ECONOMIC INDICATORS
Total energy-related costs (in 000 M€15) (11)
as % of GDP
Energy cost indicators
Energy expenditure in households (% of private consumption) [12]
fuel cost
capital cost
Average Cost of Gross Electricity Generation (€'15/MWh)
Average Price of Electricity in Final demand sectors (€'15/MWh) [13]
Energy Intensity indicator
Gross Available Energy/GDP (toe/M€15)

1 Global Warming Potential from IPCC AR5
2 The calculation of the Renewable energy share in transport follows the rules specified in the Article 27 of the Directive (EU) 2018/2001. The calculation includes the multipliers specified in Article 27(2) to demonstrate compliance with the minimum shares referred to in Article 25(1
3 Final Energy Consumption without ambient heat; including international aviation
4 Gross Inland Consumption, without ambient heat and excluding non-energy consumption
5 Renovation of building envelope only
6 Including non renewable waste
7 Including Iron and steel, Non ferrous metals, Chemicals, Non-metallic minerals and Pulp and paper
8 Including Agriculture
9 Excluding international aviation and maritime; including pipeline transport and other non-specified transport
10 Calculated from the ratio between primary production and the sum of primary production and net imports, which is equal to the Gross Available Energy (= GIC + maritime bunkers)
11 Excluding carbon pricing payments and disutility costs
12 Energy expenditure in households does not cover costs related to transport
13 For final demand sectors excluding refineries and energy branch

Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
5,1	**6,8**	**6,3**	**6,0**	**7,6**	**8,5**	**8,8**	**8,8**	**8,8**	**8,9**	**-1,2**	**3,6**	**0,2**
14,6	17,8	16,2	14,3	14,9	14,9	14,0	13,1	12,4	11,9	-2,1	0,4	-1,1
7,3	9,2	7,8	9,1	8,4	8,7	8,3	7,9	7,5	7,2	-0,1	-0,5	-0,9
5,8	6,5	5,4	4,7	4,4	4,2	4,0	3,7	3,6	3,3	-3,1	-1,2	-1,2
1,5	2,8	2,4	4,4	4,0	4,5	4,3	4,2	3,9	3,9	4,8	0,3	-0,7
46,9	45,4	43,8	45,0	43,5	49,2	55,3	62,1	82,1	86,1	-0,1	0,9	2,8
86,4	111,1	101,0	103,5	106,1	112,9	127,0	129,1	131,6	133,2	-0,7	0,9	0,8
212	190	173	148	132	120	104	95	74	63	-2,5	-2,1	-3,2

Slovenia:Reference Scenario 2020 (REF2020)

ELECTRICITY
Gross Electricity generation by source (GWh)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat, other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
Net Installed Power Capacity per plant type (MWe)
Nuclear energy
Renewables
Biomass-waste (including biogas and waste gas)
Hydro (pure pumping excluded)
Lakes
Run of river
Wind power
Wind onshore
Wind offshore
Solar
Geothermal heat and other renewables (tidal etc.)
Fossil fuels
Solid fossil fuels
Petroleum products
Natural and manufactured gases
Hydrogen and synthetic hydrocarbons
TRANSPORT
Transport activity
Passenger transport activity (Gpkm)
Buses and coaches
Passenger cars
Powered two-wheelers
Rail
Intra-EU aviation
Inland waterways and domestic maritime
Freight transport activity (Gtkm)
Heavy goods and light commercial vehicles
Rail
Inland waterways and domestic maritime
Final energy consumption in transport (ktoe) [1]
By transport mean
Buses and coaches
Passenger cars

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
15117	**16248**	**14834**	**15443**	**16757**	**19901**	**20965**	**22590**	**17748**	**17496**	**-0,5**	**2,6**	**-0,6**
5884	5657	5647	6334	5824	5824	5824	5751	0	0	1,1	-0,8	-100,0
3581	4747	4408	5332	5882	6631	7345	8940	10011	10123	1,2	2,2	2,1
120	222	275	166	236	324	309	521	755	863	-2,9	6,9	5,0
3461	4512	3849	4840	4911	5035	5037	5040	5374	5378	0,7	0,4	0,3
3151	4108	2853	4203	4122	4226	4226	4229	4309	4313	0,2	0,1	0,1
310	404	996	637	789	809	811	811	1065	1065	4,7	2,4	1,4
0	0	6	6	24	145	170	320	515	509	-	37,5	6,5
0	0	6	6	24	145	170	320	515	509	-	37,5	6,5
0	0	0	0	0	0	0	0	0	0	-	-	-
0	13	278	320	711	1127	1829	3059	3366	3372	37,7	13,4	5,6
0	0	0	0	0	0	0	0	0	0	-	-	-
5652	5844	4778	3777	5051	7446	7796	7899	7737	7373	-4,3	7,0	0,0
5271	5288	4509	3575	3103	2935	1537	1203	89	193	-3,8	-2,0	-12,7
42	8	26	6	0	0	0	0	0	0	-2,7	-100,0	-
339	548	243	196	1947	4512	6260	6696	7647	7180	-9,8	36,8	2,4
0	0	0	0	0	0	0	0	0	0	-	-	-
3111	**3186**	**4016**	**3884**	**3951**	**4616**	**5459**	**6762**	**7272**	**7256**	**2,0**	**1,7**	**2,3**
700	700	700	700	700	700	700	700	0	0	0,0	0,0	-100,0
1038	1211	1534	1668	1998	2440	3059	4194	4730	4706	3,3	3,9	3,3
59	125	175	244	139	127	131	147	190	171	6,9	-6,3	1,5
979	1074	1115	1145	1231	1231	1231	1231	1369	1368	0,6	0,7	0,5
846	903	939	939	964	964	964	964	1013	1013	0,4	0,3	0,2
133	171	176	206	266	266	266	266	355	355	1,9	2,6	1,4
0	0	5	5	20	120	140	221	317	312	-	36,9	4,9
0	0	5	5	20	120	140	221	317	312	-	36,9	4,9
0	0	0	0	0	0	0	0	0	0	-	-	-
0	12	238	274	608	962	1557	2596	2854	2854	36,7	13,4	5,6
0	0	0	0	0	0	0	0	0	0	-	-	-
1373	1275	1783	1516	1253	1476	1700	1868	2542	2549	1,7	-0,3	2,8
923	792	1345	1083	599	553	553	553	553	553	3,2	-6,5	0,0
190	185	92	29	16	16	16	14	14	0	-16,9	-5,7	-100,0
260	298	346	404	638	907	1131	1301	1975	1996	3,1	8,4	4,0
0	0	0	0	0	0	0	0	0	0	-	-	-
27	**30**	**31**	**27**	**34**	**37**	**38**	**38**	**39**	**40**	**-0,9**	**3,1**	**0,3**
3	3	4	3	4	5	5	5	5	5	-1,7	6,0	0,3
23	26	26	24	29	31	31	31	32	32	-0,8	2,6	0,3
0	0	0	0	0	0	0	1	1	1	3,0	0,4	0,7
1	1	1	0	1	1	1	1	1	1	-6,3	10,7	1,6
0	0	0	0	0	0	0	1	1	1	-5,4	10,8	1,6
0	0	0	0	0	0	0	0	0	0	-	-	-
11	**11**	**12**	**15**	**20**	**24**	**26**	**29**	**31**	**32**	**2,8**	**5,2**	**1,4**
8	8	8	10	12	14	15	16	17	18	2,3	4,1	1,1
3	3	4	5	7	10	11	13	13	14	3,8	7,1	1,9
0	0	0	0	0	0	0	0	0	0	-	-	-
1462	**1778**	**1781**	**1567**	**1809**	**1688**	**1509**	**1381**	**1291**	**1239**	**-1,3**	**0,7**	**-1,5**
71	92	111	82	120	132	132	133	131	129	-1,1	4,8	-0,1
1030	1295	1348	1122	1252	1100	922	792	702	645	-1,4	-0,2	-2,6

14

Slovenia:Reference Scenario 2020 (REF2020)

Powered two-wheelers
Heavy goods and light commercial vehicles
Rail
Domestic aviation
Inland waterways and domestic maritime
Energy demand by transport activity
Passenger transport [2,3]
Freight transport [3]
Energy demand for international bunkers
International aviation
International maritime
Other indicators
Electricity in road transport (%)
Biofuels and biomethane in total fuels (excl.hydrogen and electricity) (%) [4]
Share of Annex IX Part A biofuels and biomethane (based on REDII formula) [5]
Energy intensity indicators
Passenger transport (toe/Mpkm) [2,3]
Freight transport (toe/Mtkm) [3]
DECARBONISATION
Total GHG emissions, excl. international excl. LULUCF ($MtCO_2eq$) [6]
of which ETS sectors (stationary installations) GHG emissions [7]
International bunkers emissions ($MtCO_2$) [8]
of which aviation
of which maritime
Domestic energy-related CO_2 Emissions ($MtCO_2$)
Power generation/District heating
Energy Branch
Industry
Residential
Services (and agriculture)
Transport [9]
Other CO_2 Emissions (non land-use related) ($MtCO_2$)
Non-CO_2 GHG emissions ($MtCO_2eq$)[6,10]
Correction for emissions inventories ($MtCO_2$)
Carbon Intensity indicators
Electricity and Steam production (tCO_2/MWh)
Final energy consumption (tCO_2/toe)
Industry
Residential
Tertiary
Transport [9]

1 Excluding pipeline transport and other non-specified transport
2 Including international intra-EU and extra-EU aviation
3 Including international intra-EU and extra-EU martime
4 Including international intra-EU and extra-EU aviation and maritime
5 The contribution of advanced biofuels and biogas produced from the feedstock listed in Part A of Annex IX as a share of final consumption of energy in the transport follows the rules specified in the Article 25 of the Directive (EU) 2018/2001
6 Global Warming Potential from IPCC AR5
7 Scope as of ETS legislation at end of 2020
8 Including international intra-EU and international extra-EU
9 Excluding international aviation and international maritime, including pipeline transport and other non-specified transport
10 Excluding LULUCF-related
Source: PRIMES model

2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	'10-'20	'20-'30	'30-'50
7	9	10	12	13	13	13	13	13	13	2,6	0,2	0,3
325	357	286	326	382	389	383	377	376	380	-0,9	1,8	-0,1
28	23	25	24	41	53	59	65	68	70	0,3	8,1	1,5
1	1	1	0	1	1	1	1	1	1	-9,4	8,2	0,4
0	0	0	0	0	0	0	0	0	0	-	-	-
1506	**1824**	**1870**	**1687**	**2001**	**1886**	**1714**	**1590**	**1502**	**1451**	**-0,8**	**1,1**	**-1,3**
1138	1431	1504	1234	1428	1297	1124	1001	912	856	-1,5	0,5	-2,1
368	393	367	453	573	590	590	589	590	595	1,4	2,7	0,0
44	**47**	**90**	**120**	**192**	**199**	**205**	**209**	**212**	**212**	**9,9**	**5,2**	**0,3**
23	28	26	11	25	26	28	28	29	30	-9,2	9,3	0,6
21	19	64	109	168	173	178	181	183	183	19,3	4,7	0,3
0,0	0,0	0,0	0,2	0,7	3,6	6,1	9,0	12,3	15,0	-	34,1	7,4
0,0	2,5	1,6	4,2	6,7	7,2	8,4	8,8	9,2	9,7	5,2	5,6	1,5
		0,1	0,5	0,6	3,8	6,5	11,0	13,4	13,9	-	22,3	6,8
	45,7	45,8	43,2	38,7	32,3	27,3	24,0	21,5	19,7	-0,6	-2,8	-2,5
	3,7	2,6	3,1	2,7	2,6	2,5	2,4	2,4	2,3	-1,6	-1,7	-0,6
20,7	**19,8**	**16,9**	**15,1**	**15,2**	**15,0**	**13,0**	**11,9**	**10,5**	**10,1**	**-2,6**	**-0,1**	**-2,0**
8,7	8,0	6,1	5,2	5,1	5,9	5,0	4,7	3,9	3,8	-4,2	1,2	-2,2
0,1	**0,1**	**0,3**	**0,4**	**0,6**	**0,6**	**0,7**	**0,7**	**0,7**	**0,7**	**10,3**	**5,1**	**0,3**
0,1	0,1	0,1	0,0	0,1	0,1	0,1	0,1	0,1	0,1	-9,2	9,3	0,4
0,1	0,1	0,2	0,4	0,5	0,6	0,6	0,6	0,6	0,6	19,3	4,7	0,3
15,5	**15,4**	**12,8**	**10,9**	**11,1**	**11,0**	**9,4**	**8,5**	**7,3**	**6,9**	**-3,4**	**0,1**	**-2,3**
6,3	6,2	4,6	3,7	3,5	4,2	3,5	3,4	2,7	2,6	-5,0	1,1	-2,3
0,0	0,0	0,0	0,0	0,0	0,1	0,1	0,1	0,1	0,1	-5,4	26,2	0,8
2,4	1,9	1,6	1,6	1,6	1,6	1,4	1,2	1,1	1,1	-1,8	0,5	-2,0
1,5	1,2	0,7	0,6	0,5	0,4	0,3	0,3	0,3	0,3	-6,4	-4,6	-2,1
1,0	0,9	0,6	0,5	0,5	0,4	0,3	0,3	0,3	0,3	-6,1	-3,2	-1,1
4,3	5,2	5,3	4,5	4,9	4,4	3,7	3,2	2,8	2,5	-1,4	-0,3	-2,7
1,3	**0,9**	**0,9**	**0,9**	**0,9**	**1,1**	**0,9**	**0,9**	**0,8**	**0,8**	**-0,4**	**2,1**	**-1,5**
3,7	**3,4**	**3,3**	**3,5**	**3,2**	**3,1**	**2,8**	**2,6**	**2,5**	**2,5**	**0,2**	**-1,2**	**-1,1**
0,2	**0,0**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-0,1**	**-**	**0,2**	**-2,3**
0,42	0,38	0,31	0,24	0,21	0,21	0,17	0,15	0,15	0,15	-4,5	-1,4	-1,6
1,89	1,84	1,75	1,69	1,55	1,40	1,24	1,13	1,03	0,96	-0,8	-1,9	-1,9
1,45	1,48	1,33	1,38	1,29	1,19	1,00	0,88	0,81	0,78	-0,7	-1,5	-2,1
1,28	0,97	0,62	0,61	0,43	0,34	0,30	0,27	0,26	0,25	-4,5	-5,6	-1,5
1,65	1,33	1,09	0,96	0,73	0,59	0,55	0,54	0,50	0,43	-3,2	-4,7	-1,6
2,97	2,93	2,97	2,87	2,73	2,60	2,45	2,31	2,17	2,04	-0,2	-1,0	-1,2

14

15

Investment Potential in the Energy Sector of SE Europe

Investment Potential in the Energy Sector of SE Europe

15.1 Methodology

In this chapter, we analyze the actual investment potential in the energy sector of the SEE region in all different areas of activity and per country, and we also identify energy related business opportunities.

Attempting to identify risks and strengths of the regional energy sector, we realize that two major opposite forces work counteractively, at least in the short-term. On the one hand, there is the pandemic effect, which caused major delays and disruption on the design and implementation or integration of new energy projects, since major flows of public finance has been redirected to health sector and infrastructure, as well as to social cohesion instruments so as to sustain private debt and unemployment at lower levels; while, on the other hand, the European strategy for climate change, envisaged via the Green Deal, had precipitated that considerable resources shall be devoted in order to drive the road for a European environmentally neutral economy. Thus, this movement, which had presided the advent of "exogenous" pandemic, had created space and commitment for further actions towards a more comprehensive energy policy mix.

Although pandemic had a major influence on European public finance and investment strategy (see Next Generation Fund prerogatives), the fact that environmental and health issues are somehow associated, generates optimism that in the mid-term and long-run, initiatives taken will be more complementary, rather substitute elements. The establishment of the Recovery and Resilience Fund is projected to induce several multi-national initiatives in the energy sector.

In quantifying the anticipated investment over the next 10-year period (2021-2030), we have followed a distinct methodology, whereby data has been organized in two basic groups (1):

- The first group includes financial data on a country-by-country basis, as shown in section 15.9, compiled by IENE sources and associates in many of the region's countries under review. A common matrix has been used for all countries and anticipated investment is presented per energy sector in each country. No major transnational energy infrastructure projects, such as main oil or gas pipelines, have been included in this category. This type of information is presented separately in section 5.
- The second group includes financial data on all major national projects of EU Balkan countries, attempting to codify the priorities set by National Plans on Energy and climate and the prerogatives of Recovery and Resilience programs. Needless to say that some projects are funded on a bilateral basis. Financing issues and the role of investment banks and EU institutions are also discussed.

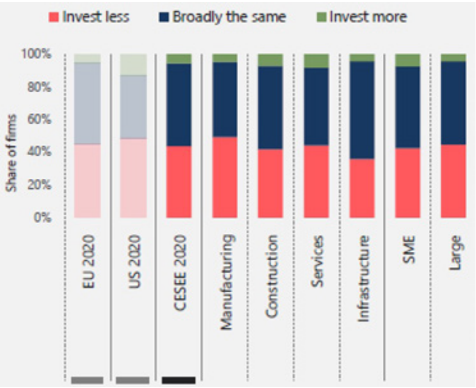
15.2 Regional Investment Outlook

The coronavirus pandemic has created a new order of policy preferences and priorities for governments and societies, in favour of direct public expenditures for health and social protection schemes, which resulted in the shift or suspension of policy priorities for immediate action towards climate change and energy efficiency. A recent study, conducted by European Investment Bank (2020), shows that pandemic influence on investment trends was rather disruptive. Less than half of CESEE firms say they expect to invest less in 2020 due to COVID-19. About half of the firms expressed that their investment positions remained the same. A marginal rate of 5% of the companies expects to invest more. This picture is found also in similar trends with the EU average.

Of course, some analysts argue that pandemic accelerated the transformation of economies and production model adaptability to new challenges.

In this mutable argumentation framework, pandemic influenced policy preferences towards a more determined strategy over combating health, environmental and climate risks. That is, energy policy is expected to remain at the epicenter of policymakers thanks to these new evolutionary conditions.

Figure 15.1 **Investment Dynamics, Impact of Covid-19 on investment decisions**



Source: EIB Group survey on investment and investment finance 2020, CESEE overview

Notwithstanding, investment flows have shown significant shifts departing from the traditional financing and public policy schemes, allowing for the development of new funding instruments (see green bonds, sustainable development goals, green efficiency targets) and more perplex multi-lateral financing vehicles, via the support of international development banks). Each European country faces different challenges, according to the level of economic and energy integration, while also fiscal consolidation yet remains a major risk for some of them. The deployment of new development plans, the formation of national and European growth strategies, and the increasing role of financial institutions in sustainable finance have created new areas of investment.

Following communication with a number of individual sources and associates of IENE in the different countries of the region, but also based on analysis from a number of published sources, a mid-term energy investment profile of each country has been compiled. A general observation is that investment type information is quite difficult to collect for each country and possibly harder to confirm, mainly in view of the prevailing uncertainty concerning the implementation of several projects.

In the next sections, a snapshot of the energy investment profile of all 15 countries of the study is provided. As the information for each profile usually vary, stemming from different sources, quantitative and qualitative deviations have been inevitable, since validation and cross checking of information provided would not always be feasible. In certain cases, the information included is based entirely on IENE's own estimates, which have been compiled though the use of industry norms, market information and trends from other countries. In almost all cases, IENE's estimates have been formulated following discussions with local economic and industry sources familiar with the country.

The energy investment figures, which are provided under each category, are the outcome of careful research and represent the cumulative value of anticipated investments for various projects. However, the realization of many of these projects is conditional on several variables which are not always easy to list or quantify.

In order to improve our conception of each country's energy investment orientation, a brief discussion follows, which aims to highlight the most important of each country's energy related investment and business opportunities. In the view of the prevailing uncertainty over economic development prospects, thanks to the pandemic effect, but also due to the geostrategic turbulence in SE Europe (Turkey, Syria, Libya), which inevitably affect energy strategies of focal European partners and consequently decision-making process, we have considered alternative scenarios.

Country Notes

An outline review is made under each country's heading of policies and key projects, which are most likely to materialize by the end of the 2020s. This is, by no means, an exhaustive and fully accurate list and is only intended to serve as a brief approximation on important areas of interest which may present business opportunities.

Albania

Since 1999, Albania's energy mix is dominated by hydrocarbon products, while electricity from renewable energy sources (hydro) has increased at a moderate level demonstrating at the same time high fluctuations.

Albania's 2017-2021 program stipulated that the government would aim to further develop the electricity sector, transforming it into a financially, operationally and technically viable sector capable of meeting the growing domestic energy demand, prioritizing the integration of the domestic energy market into regional and European markets, and reducing import dependency. The re-elected government of Socialist Party of E. Rama (April 2021) is expected to continue the energy strategy with no major deviations.

The government's policy will continue to be oriented towards increasing the security of energy supply to consumers, aiming at supporting the sustainable economic development of the country, through increasing employment and promoting renewable energy and energy efficiency, stimulating competition in the market, ensuring stability and minimizing costs for Albanian consumers, as well as ensuring environmental protection.

Some of the main objectives, set by the National Energy Strategy 2018-2030, are summarized below:

- Continuing to reduce losses in the electricity distribution network from 26.4% in 2017 to 10% in 2030;
- Continuing to increase electricity receipts from 90% in 2018 to 98% in 2030;
- Increase the contribution of primary energy sources to total primary energy supply at 52.5% in 2030;
- Electricity market opening rate to reach 100% by 2025;
- The Albanian economy and society to reach a level of energy saving versus total consumption of 15% by 2030;
- The target of renewable energies to total consumption reaches 42% in 2030;
- GHG emissions reduction in total to reach 11.5% by 2030;
- Penetration of natural gas against total supply of primary energy sources reaches 20% in 2030.

In specific areas, the new oil and gas projects in Albania are mainly related with the development of the national natural gas network and its connection with the region like the IAP and ALKOGAP pipelines. Albania has prepared its gas master plan since 2016, while prefeasibility studies have been prepared for IAP and ALKOGAP.

Despite the development of energy projects, the country will continue to face serious energy imbalances over the coming years; therefore, there is space for new investment and business opportunities, especially in the still dormant electricity retail market.

These investment opportunities in Albania focus mainly on the further development of the electricity sector, the promotion of RES in the core economy and the mobilization of funds to achieve energy efficiency targets for households and businesses.

Bosnia & Herzegovina

The energy sector of Bosnia and Herzegovina is characterized by significant domestic coal resources and the total absence of oil and natural gas production. Coal production in conjunction with hydrological reserves enables Bosnia and Herzegovina to export significant quantities of electricity. Bosnia and Herzegovina is totally dependent on imported oil and gas.

By signing the Treaty Establishing the Energy Community, Bosnia and Herzegovina accepted a list of obligations related to the standards of the EU energy market with which it will integrate in due course. This is to be achieved by the gradual transposition of the EU acquis, which means the implementation of the relevant

EU directives and regulations pertaining to electricity, gas, security of supply, environment, competition, renewable energy sources, energy efficiency, oil, statistics and infrastructure. The basic strategic goal of Bosnia and Herzegovina is to speed up the harmonization of its legislation with the acquis, and transpose and implement the obligations assumed under the Energy Community Treaty.

Investment priorities, as derived from the Framework Energy Strategy, are as follows:
• Efficient use of resources
• Secure and affordable energy
• Energy efficiency
• Energy transition and environmental responsibility
• Development and harmonization of regulatory and institutional framework

The Framework Energy Strategy of Bosnia and Herzegovina until 2035 analyzed several different scenarios for new power plants. Selection of one of the scenarios is a discretionary decision of stakeholders at entity and State level, in accordance with legal and regulatory obligations. It should be noted that a significant number of new thermal power plants are currently planned within the context of the Framework Strategy, but it is questionable how compatible they are with EU's energy policy. According to the "most relevant" scenario ("entity scenario"), the installed capacity in thermal power plants by 2035 will increase by 189% (compared to 2016). That means that 2,600 MW in new thermal power plant capacity is planned, but meanwhile six (6) thermal power plant units are going to be decommissioned with total capacity of 926 MW.

Overall, investment opportunities in Bosnia-Herzegovina mainly focus on exploiting further the indigenous energy potential and reducing oil dependence, by stimulating funding on better electricity network and thermal plants and the importation of natural gas and the development of all different forms of Renewable Energy Sources.

Bulgaria

Bulgaria's energy mix appears well diversified since the country uses a wide variety of energy sources. Moreover, around 65% of the country's needs are covered by sources that are almost entirely domestic: solid fuels, renewables and nuclear. The availability of an oil processing infrastructure and the country's ability to transport and distribute petroleum products in stable volumes, as well as the large investments in its expansion and modernization, offer grounds for optimism both in terms of security and future market development. This forecast is further supported by the current full liberalization of the oil market, ensuring the free movement of energy flows and products.

Diversification of sources and routes for the supply of natural gas is important for the country's energy security and independence. According to the ES (2011), the country will strive to build reverse interconnections with Greece, Turkey, and Serbia and will look into possibilities for the extension of the existing gas storage at Chiren, as well as for building of a new storage facility in Galata. There is already an interconnection with the Romanian transmission system, established in 2016, but the compression station on the Romanian side is still to be put into operation. The National Energy and Climate Plan 2021-2030 has similar targets as the ES.

The interconnections with Greece and Serbia, as well as increasing Chiren's capacity are under way and included in the list of EU Projects of Common Interest (PCI) and have received grant support for feasibility studies and construction works under the European Energy Programme for Recovery, the European Fund for Regional Development and the Connecting Europe Facility. Overall, the investment opportunities in Bulgaria focus mainly in the opening up of the domestic gas and electricity market, especially at retail level, the opening up of the oil market to more stakeholders and in renewables where the government, under pressure from Brussels, will have to streamline project licensing and implementation so as to be able to attract more investors.

Croatia

Croatia's energy policy and strategy is focused in achieving EU's goals in terms of reducing greenhouse gas emissions, increasing the share of RES, energy efficiency, security and quality of supply, and developing the EU's internal energy market, as well as making available the necessary resources, energy infrastructure and thus ensure competitiveness of the economy and the energy sector.

The transformation of the energy sector into a low greenhouse gas system will involve all sectors of energy production and consumption, as well as systems that transmit and supply energy to customers. In their transformation, energy systems must continue to fulfil their primary purpose, which is secure supply of energy to all customers, at reasonable prices and with minimal environmental impact.

The Integrated National Energy and Climate Plan for the period 2021-2030 builds on existing national strategies and plans and takes into consideration the five dimensions of the Energy Union. The five dimensions of the Energy Union are: decarbonisation, energy efficiency, energy security, the internal energy market and research, innovation and competitiveness.

Major planned new projects are related to: gas exploration (described in Chapter 8), development of gas trade (following the opening of the Krk LNG terminal), the expansion of the gas transmission network and development of a new underground gas storage facility. Pressure is growing for more RES related investments.

Overall, investment opportunities in Croatia mainly focus on the expansion of the gas network and the improvement of RES contribution to total energy production.

Cyprus

Due to the country's limited indigenous energy resources Cyprus is highly dependent on energy imports, at a level above the average of the European Union. In the EU in 2017-2019, the average energy dependency was 55%, while in Cyprus this was around 96%.

The energy mix continues to be dominated by oil and petroleum products, which contributed by 88.1% of the total energy supply in 2018. Over the period 2016-2018, the share of oil products declined, while the contribution of renewable energy to energy supply has steadily increased reaching 10.3% in 2018.

The situation is expected to change in the near future as RES penetration increases and once natural gas from LNG imports becomes available to the local market in 2023 (replacing fuel oil for power generation and in industry, and in the long term in the household sector). It is anticipated that this will be reflected by a relatively large decline in the share of oil products in the energy mix, although the impact will not be that high, since the demand for oil products in the transport sector will continue to be dominant.

The implementation of the energy policy in Cyprus while attaining the climate and environmental targets requires a radical transformation of the energy system over the next decade (2021-2030) and, therefore, the implementation of significant investments in energy infrastructure as well as in energy efficiency.

The national targets for the next decade are specified in detail in the National Climate and Energy Plan (NECP) on a mid-term basis, up to 2030, and should serve as a basis for an ambitious long-term strategy aiming towards the reduction of Greenhouse Gas (GHG) emissions by 2050. Therefore, the decarbonisation dimension is the first and foremost component of the NECP structure.

There is a binding decision for the decommissioning of the existing oil products storage terminal, as well as for the relocation of the existing storage facilities of the local petroleum and LPG trading companies. A strategic oil stocks depot will be set up and operated by the Cyprus Organization for the Storage & Management of Oil Stocks (KODAP). The introduction of natural gas to the local market in Cyprus is a main priority for the energy sector. The project, to introduce LNG through regasification unit (FSRU) is estimated at €290 million and €101 million has been secured through a grant from the EU under the Connecting Europe Facility (CEF) financial instrument, while the Cyprus Electricity Authority will contribute €43 million securing a 30% stake at ETYFA.

Overall, investment opportunities in Cyprus are to be found in renewables, the transformation of networks and the introduction of smart meters for electricity distribution, in power transmission networks, importing natural gas and development of a gas grid across the island, increasing energy efficiency in power generation and use by households, businesses, the public sector and alike in the water sector, transport infrastructures and sustainable mobility, as well as in technological research.

Greece

Over the last decade, Greece has undertaken one of the most dramatic transformations in its energy sector since the electrification of the country after World War II. Significant reforms have reshaped the energy market to make it more competitive, while major infrastructure projects are under way to connect the grid to Europe, and the mainland to the islands. Combined with investments in natural gas and other supply infrastructure, Greece's new energy sector could play a major role in supplying SE Europe.

The new national strategy of renewable energy, e-mobility and energy efficiency promises to create an entirely new industrial sector that will succeed the state-driven energy sector of the 1950s. A recent study, by the Foundation for Economic and Industrial Research (IOBE) and diaNEOsis, projects that over the next decade, investment in Greece's Green Deal could result in an additional €2.6 billion in GDP and the creation of 35,000 jobs.

The plan also calls for major upgrading of energy efficiency in the country's building sector and encouraging RES sourcing for heating and cooling needs. Currently, only 6.4% of Greek homes meet the EU top standards for energy efficiency, and 60% of household energy goes to heating. The upgrade will reduce energy consumption but will also provide a boost to the country's construction and building materials sectors.

Overall, the investment opportunities in Greece are to be found mainly in RES, in natural gas, in new LNG facilities and gas trade, in energy efficiency improvement focusing on buildings, in electricity trade and retail and in hydrocarbon exploration and production.

Hungary

The National Energy Strategy 2030 of Hungary with an outlook to 2040 provides the strategic basis and defines the energy and climate policy priorities of the country. The strategy is laid with the binding EU 2030 goals, and is designed to attain a number of policy goals while ensuring energy sovereignty, decarbonization of energy production through the utilization of nuclear and renewable technologies and maintaining sustainable energy prices.
These policy goals can be summarized as follows:

- The final energy consumption of Hungary - in parallel with strong economic growth - should not exceed the 785 PJ of 2005, further increase beyond 2030 should only be supplied by carbon neutral energy sources;
- The GHG emissions of the country should be at least 40% below that of 1990 in 2030.
- Decrease the need for energy imports in general and decrease the share of electricity imports in the final electricity consumption from 32% (2013-2017 average) to below 20% by 2040;
- Increase the use of renewable energy

sources to reach 21% in the gross final energy consumption by 2030 from 13.3% in 2017;
- 90% CO_2 emission free electricity generation by 2030 based on nuclear and solar technologies;
- Increase the share of the local RES production in the electricity consumption to 20% by 2030 and to close to 30% by 2040;
- The installed total solar capacity should exceed 6,0 GW by 2030 and approach 12,0 GW by 2040;
- Incentivize the use of smart meters in order to increase the flexibility of the grid – and plans at installing 1 million smart meters;
- Enhance the utilization of the country's geothermal potential;
- The local lignite assets should be considered strategic reserves and current lignite capacity at Mátrai Erőmű should be converted to low-carbon technologies;
- The energy and climate goals shall be met by keeping low the energy costs low.

The strategy estimates that the costs of reaching the 2030 climate and energy goals are in the range of 14.700 billion HUF (€ 44.5 bn current prices). Hungary's final integrated national energy and climate plan sets a 2030 target for greenhouse gas (GHG) which is -7% relatively to 2005.

With regard to renewables, the final plan provides for a renewable contribution of 21%. The national plan explains and quantifies the measures required to achieve the national renewables contribution and increase renewable shares in the electricity, heating and transport sectors.

Concerning the internal market and energy security, Hungary acknowledges the need to keep flexible power generation assets in the system. The plan describes ongoing projects to diversify supply routes and sources of natural gas, including a timeline for their implementation. It includes some measures to ensure the security of nuclear fuel supply.

National objectives and funding targets for research, innovation and competitiveness are mainstreamed and consistent with the other dimensions. In terms of quantified targets, Hungary aims to have implemented at least 20 pilot innovation projects by 2030, with a minimum of 10 patents registered in the course of their implementation.

Overall, the investment opportunities in Hungary mainly focus on the effective substitution of the carbon economy with RES, increase the share of solar and geothermal generation, upgrade its electricity distribution system while also developing further the company's nuclear capacity.

Israel

Over the last years, Israel's energy policy has focused in reducing emissions and pollution and GHG in power generation, because this is the sector which is the easiest in achieving the greatest impact. The introduction of indigenous natural gas for power generation and in industry has greatly helped in this direction. A second goal has been to increase competition, in both the power and natural gas markets through the introduction of the private sector, as well as to reduce prices in both of these markets.

Since Israel produces large volumes of natural gas, the government's goal is to reach more than 80% natural gas use and 17% renewable energy contribution in the power sector by 2030 and minimize coal consumption. In November 2019, the Ministry of Energy, under pressure from environmental groups, stated that the renewable target will be revised and may increase to 25%-30% by 2030 and zero coal generation already by 2025. These targets however are ambitious and not yet totally backed by government measures.

With regard to energy efficiency schemes, a new program based on the "Guidance for Energy Efficiency Action Plans under Directive 2012/27/EU", was approved by a government decision in 2017. This reduces the government's 2030 electricity consumption target to 80 TW/h compared to the "business as usual" scenario, by which electricity generation in Israel would reach 96 TW/h in 2030. The government program consists of several supportive tools:

- Financial: grants, and subsidies in the form of loans and tax benefits
- Regulation: energy labelling and minimum energy performance standard (MEPS)
- Public awareness

Overall, the investment opportunities in Israel are to be found in the further increase of RES in the energy mix maintaining gas strategic supplies through further exploration, while opening the electricity demand sector to private stakeholders.

Kosovo

The structure of the primary energy consumed in Kosovo in 2019 consists of coal, petroleum products (gasoline, diesel, fuel oil, kerosene and LPG), biomass, hydro, wind, solar and biofuels. Electricity is treated as a primary source.

Kosovo has the prerequisites for electricity production, not only to cover its own needs, but also to export it. Kosovo's power system is designed to produce lignite-based energy. Nonetheless, the domestic production is not sufficient to meet growing consumption and therefore part of Kosovo's electricity consumption is covered by imports during different time periods especially in peak hours.
The Energy Strategy of Kosovo 2017-2026 sets out the basic objectives of the Government of Kosovo in energy sector development, taking into account sustainable economic development, environmental protection, sustainable and reliable energy supply to final customers, efficient use of energy, development of new conventional and renewable generation capacities, creation of a competitive market, development of the gas system, and creation of new jobs in the energy sector.

The official government policy is to promote and support the inclusion of Kosovo in all regional natural gas projects. The Trans Adriatic Pipeline (TAP) project could offer great opportunities to Kosovo to connect to the international natural gas network. In this regard, depending on the regional developments of gas projects in Southeastern Europe, the government remains committed to use all opportunities to get involved in joint natural gas projects as coordinated by the Energy Community. As part of its Energy Strategy for 2017-2026, Kosovo is also aiming to establish a Gas Transport System Operator and Gas Distribution Operator and invest in natural gas infrastructure.

Overall, investment opportunities in Kosovo's energy sectors are to be found in the participation of the country in regional natural gas projects, on the development of renewables market and in bridging the electricity consumption gap. The construction of a gas pipeline, linking Kosovo to North Macedonia, could provide the main infrastructure for gas introduction in Kosovo. In view of increased gas market liquidity in Greece and the planned gas interconnector between Greece and North Macedonia this could develop into major project in the current decade and hence attract considerable investment interest especially in establishing a gas grid in the country and decarbonizing to a large extent power generation.

Montenegro

Montenegro is preparing a new energy strategy, which will put priority on renewable energy sources in order to achieve climate neutrality, while the country's national energy and climate plan (NECP), which is also being drafted, will set a deadline for a coal phaseout.

As a candidate country, Montenegro has accepted an obligation to harmonize its energy sector with the EU's policy of reducing and eventually bringing CO_2 emissions to zero. A new energy strategy is being developed, which will give priority to renewable sources in order to gradually reduce emissions.

The Energy Policy of Montenegro until 2030 is the main strategic document which establishes three main priorities for the development of the energy sector of Montenegro: security of energy supply, development of a competitive energy market and sustainable energy development. The Energy Development Strategy specifies long-term development objectives and guidelines for the development of energy supply and meeting of energy demand, while taking into account technological and economic criteria and environmental protection criteria; the development direction of energy infrastructure, taking into account possibilities for encouraging the use of renewable energy sources and increasing energy efficiency and long-term energy balance forecasts, timeline and methods to be used for tracking progress and monitoring the achievement of objectives, as well as the assessment of their effects on the economy; tentative financial resources for the implementation of the strategy. Montenegro imports 100% of its oil needs (oil corresponds to 39% of the total energy consumption). The country has large enough hydroelectric potential, but only 17% of it is actually exploited.

The government of Montenegro is implementing a number of preparatory steps for potential gasification which could be achieved through infrastructure development related to the Ionian-Adriatic Pipeline (IAP) and/or the Trans Adriatic Pipeline (TAP). The construction of a natural gas pipeline network will enable both a stable natural gas supply to Montenegro and its transit to other countries in Western Balkans.

Overall, the investment opportunities in Montenegro focus mainly on effective utilization of hydroelectric power, the development of renewables sector and the implementation of energy efficiency strategy for the private and public sector.

North Macedonia

North Macedonia, as a candidate country for membership in the EU, faces certain challenges related to the implementation of structural reforms, of which the energy sector is of special significance for the country's overall development.

The country has actively participated in regional initiatives, considering that it was the first country in the region to sign a Stabilization and Association Agreement with the EU in 2001. In 2005 it was granted candidate status for EU membership.

With respect to its international commitments referring to the energy sector, North Macedonia signed and ratified the Energy Charter Treaty and the Protocol on Energy Efficiency and Related Environmental Aspects, the Energy Community Treaty (EnCT), the United Nations Framework Convention on Climate Change and the Kyoto Protocol. EnCT represents North Macedonia's main agreement in force with EU acquis requirements, and extends the acquis to the territory of the country.

The new Energy Development Strategy has projected growing consumption of petroleum products in all considered scenarios, which would create a need for larger volumes of storage capacity in future. Therefore, the main recommendation is that the country should ensure availability of necessary infrastructure for stock keeping via Action Plan.

With regard to natural gas exploitation opportunities, the interconnection with Greece, which is included in the Projects of Mutual Interest (PMI) list and is expected to be completed by 2023, is identified as a key project that will help diversify supply. It will connect North Macedonia to the Trans Adriatic Pipeline (TAP) which brings natural gas from the Caspian region to Europe via Turkey and Greece. TAP could become a major gas supplier for Kosovo.

Overall, the investment opportunities in North Macedonia mainly focus in attaining an efficient consumption balance in the electricity sector by diversifying energy resources, while also exploiting the potential to participate in the creation of a main natural gas route that will traverse the country. Most encouraging are also steps which the government is taking to attract investment in a bigger scale in RES, mainly solar photovoltaics and wind. Efforts to improve energy efficiency in buildings will most likely result very soon in integrated national plan capable of attracting investment.

Romania

Romania constantly ranks as the third (and second, after Brexit) least energy dependent country in the EU. While the EU-27 average rate of energy dependency was 58% in 2018, Romania's dependency rate was a little over 20%. Along with Denmark and Estonia, Romania was among the top 3 countries with the lowest energy dependence in 2018. This is due to rich domestic resources such as hydro, coal, oil, natural gas, nuclear and renewables.

The primary objective of Romania's energy policy is to ensure energy supply from its own internal sources. According to the final Integrated National Energy and Climate Plan (INECP) submitted by Romania in April 2020, energy policy is structured around 5 dimensions: decarbonization, energy efficiency, energy security, internal energy market, and research, innovation and competitiveness.

The energy import forecasts for 2017-2035 suggest that Romania will remain an electricity exporter until 2035. This, however, is no longer the case, since in 2019 Romania became a net electricity importer. Whether Romania will be an importer or exporter of electricity will depend on how fast new generation assets will come online. Most likely, until 2025 Romania will be a net electricity importer, and will revert to electricity exporter status only after the additional generation capacity is put in place.

The investment requirement in the energy system (only on the demand side) until 2030 was estimated back in 2018 to be €20 billion on average (with a minimum of €15 billion and a maximum of €30 billion).

This estimate was made before the Green Deal was introduced, so it does not reflect the new EU level of ambition for clean energy. It is, therefore, safe to conclude that the updated investment requirement should be at least €28-30 billion, that being a conservative (a minimum) estimate to include all investments made (private, public and EU-funds) and distributed as follows by sector:

- RES and storage: €15-17 billion (could go as high as €20 billion if offshore wind takes off)
- Grids (electricity, heat, natural gas): €3 billion
- Energy Efficiency for Buildings: €4 billion
- Nuclear: €4 billion
- Natural gas-fired generation: €2 billion

Overall, the investment opportunities in Romania focus on the maintenance of net energy exporter's advantage, while also implementing optimal financial strategy for combining renewables development, nuclear power and energy efficiency targets.

Serbia

All national goals, activities and measures in the energy sector are in line with the objectives of the Energy Strategy of Energy Community which implies creating a competitive and integrated energy market, attracting investment in the energy sector and ensuring safe and sustainable energy supply. Serbia's coal-based energy sector is under pressure to adapt to new political priorities and the new decarbonized energy landscape.

In view of the three components of EU's energy policy, i.e. security of supply, competitiveness, and sustainability, Serbia as an EU accession country will have to harmonize its energy and climate policies.

Serbia currently consumes about two and a half billion cubic meters of gas annually. Industrial production is beginning to grow and Serbia will certainly need more gas. In the past five years, Serbia's natural gas consumption increased by about 5% per year, while the domestic production has fallen significantly.

Improving the energy efficiency and decarbonizing the Serbian energy system is a capital-intensive process that essentially involves the substitution of fossil fuels. From the transition perspective, natural gas can provide near-term benefits when replacing more polluting fuels. Scaling up the utilization of renewable energy sources is important not just for power, but for the heating and transport sectors also

In June 2017, an agreement for a gas Road Map was signed between the Ministry of Mining and Energy and Gazprom and covered the implementation of the Balkan Stream project, and the construction of the main transport gas pipeline in the territory of the Republic of

Serbia, from the border with the Republic of Bulgaria (Zajecar) to the border with Hungary (Horgos). This major pipeline, part of the TurkStream project to be completed in 2022, will transport gas to Hungary and to Austria, and it will certainly help to enhance further gas use in Serbia. Serbia has also a great potential for the development of renewable energy. The further development of available potential must be justified in terms of sustainability and taking into account economic, environmental and social feasibility parameters.

Overall, the investment opportunities in Serbia mainly focus on the further development of natural gas in terms of infrastructure and market, the development of an electricity retail market, with the parallel and effective development of renewable energy and energy efficiency applications in the building sector.

Turkey

Turkey has the highest rate of energy demand increase among OECD countries. During the past years, Turkey has been ranked only second to China in the increase of electricity and natural gas demand, and it appears capable of becoming the biggest natural gas and electricity market in the region, while it shows very high import dependency in meeting its energy demand (almost 75%).

One of the main goals of Turkey's energy strategy is to diversify routes and resources to strengthen its security of energy supply. Turkey also aims to contribute to regional and global energy security and to become a regional trade center in energy. The fundamental elements that constitute the international dimension of Turkey's energy strategy are:

1. To ensure the diversification of routes and resources in the supply of oil and natural gas, taking into account the increasing demand and import dependency,
2. To contribute to regional and global energy security,
3. To be a regional trade center in energy,
4. To consider social and environmental impact in the context of sustainable development in every phase of the energy chain,
5. To increase the share of domestic and renewable energy in electricity production,
6. To include nuclear power in its energy mix.

The main operational objective of Turkish energy policy is to provide the highest contribution to national welfare by supplying uninterrupted, sustainable, high quality, reliable and cost-effective energy from diversified sources in a most efficient and environmentally conscious manner (Strategic Plan 2015-2019). In this regard the main priorities are highlighted below:

(i) Maximum utilization of renewable and indigenous sources,
(ii) Diversification of energy suppling countries and supply routes,
(iii) Reduction of energy intensity,
(iv) Introduction of nuclear energy into the energy mix,
(v) Reduction of environmental impact in the energy system,
(vi) Development of a competitive internal energy market (oil, gas, electricity).

After the US administration ended the sanction waivers, Turkey in July 2019 ceased importing crude oil from Iran. The gap was filled with increased imports from other countries.

Despite all the diversification efforts, Turkey is still highly dependent on natural gas imports from the Russian Federation. Negative economic conditions in the second half of 2018 and the first three quarters of 2019 may be the reason for reduced natural gas consumption, but in 2019 the effects of the mild winter and high electricity generation from renewables and hydropower plants were also accountable.

The share of Renewables (wind, solar and geothermal) in 2018 was 8.1% more than double since 2013. Over the last decades Turkey's energy import dependency grew from 50% to over 70% and reached its highest level of 77.9% in 2015. The results of the efforts to utilize local resources were rather modest. Many investment projects for new hydropower and coal capacities were mainly hindered by NGO resistance and a deteriorating investment climate. Following discovery of a major gas find in offshore Black Sea in August 2020, within Turkey's EEZ, interest for further gas exploration has grown.

Finally, it is important to underline that Turkey's energy production strategy is increasingly being focused on the use of hydrogen as primary energy source in many fields of economic activity. Thus, indigenous production of hydrogen in the near future has moved to the epicenter of its energy policy and efforts are in place to attract interest from foreign investors and energy stakeholders in the field of hydrogen production.

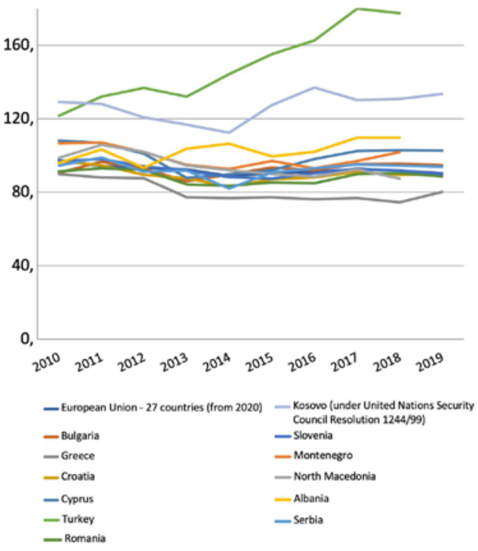
Currently, investment opportunities in Turkey's energy sector mainly focus on the diversification of different resources, on the development of the various energy networks (oil, gas, electricity), with emphasis given on renewables and hydrogen.

15.3 Energy efficiency and energy transition

Lacking availability of an yet more complex and statistically oriented composite index for measuring energy efficiency in the member countries, Eurostat utilizes primary energy consumption as a proxy indicator to assess energy performance of European countries. As Figure 15.2 shows, Turkey, Romania, Slovenia, North Macedonia have improved their relative position, by reducing the volume of primary energy consumption.

All CESEE countries have also passed through a period of lower consumption during the economic crisis. However, it was only recently that Turkey began to show a deceleration of its energy consumption.

Figure 15.2 **Energy consumption and efficiency in Europe**



Source: Eurostat, 2021 (Energy efficiency [NRG_IND_EFF__custom_960704]

The issue of effective energy transition is closely associated with the target of energy efficiency. The European Union published its policy for the «Just Transition», where it describes the main principles and milestones for reaching the quantitative and qualitative targets of sustainable energy transition. Governments and stakeholders set policy priorities and deploy measures to support the sustainable growth, to secure job retention and protect social cohesion as countries move towards a low-carbon energy system.

This direction requires an inclusive approach in order to assess effectively energy investment decisions, most of which are substitutes, rather than complementary, depending on the maturity and extent of energy networks.

According to WEF (2021), the shift of energy policies during the decade 2010-2020 signifies a strong turn into a different global energy mix. In 2010, the investment for energy transition was estimated at $ 250billion globally, while in 2020 this figure had reached $ 500bn, that is 100% increase in investment for specific actions on energy transition.

World Economic Forum publishes annually the index score for the efficient transition of the countries across the world.

This index is composed from two major distinct sub-indices (factor analysis)[1], System performance and Transition readiness, each examining some additional parameters.

Table 15.1 **WEF transition Index**

System performance imperatives	Transition readiness: enabling dimensions
Security and access	Capital and investment
Environmental sustainability	Energy system structure
Economic development & growth	Human capital and consumer participation
	Infrastructure and innovative business environment
	Institutions and governance
	Regulation and political commitment

Source: WEF, Energy Transition Index framework, April 2021

The most recent publication shows considerable variations between the countries of SE Europe in the field of energy transition. According to Table 15.2, western Balkans (Croatia, Albania, Slovenia) seem to perform better due to the proximity with Europe and readiness of investment plans, while other EU Balkan countries perform below European average, anticipating resolution of energy network development.

Central non-EU Balkan countries and Turkey seem to underperform mainly due to the fact that institutional framework still needs to be further integrated and geostrategic risks to be mitigated.

Table 15.2 **SE Europe ranking, Energy Transition Index (WEF), 2012-2021**

Rank	Country	System performance	Transition readiness	Total
23	Croatia	71,8	61,4	67
25	Albania	74,5	58,3	66
28	Israel	71,2	60,7	66
31	Slovenia	70,8	60,4	66
32	Hungary	71,0	59,8	65
38	Romania	70,3	58,4	64
51	Cyprus	64,5	56,5	60
52	Montenegro	62,2	58,0	60
54	Greece	66,7	53,2	60
58	Bulgaria	60,5	56,7	59
63	Turkey	60,9	54,2	58
84	Serbia	59,4	47,6	53
98	Bosnia-Herzegovina	55,9	44,8	50

15.4 Energy Investments and Cost of Capital

Energy investments in Europe have generally shown a relative halt during the two last years, thanks to pandemic dynamics and the reshuffle of energy policy priorities. The inauguration of the Next Generation Fund by the EU, which precludes certain actions on account of environmental standards and energy efficiency investments, is anticipated to reverse the initial reported stagnation in the energy sector. It is quite possible that during the next decade, EU will experience a total restructuring of its energy mix in favor of RES, with a clearly defined neutrality target to be set before 2050.

[2] "An effective energy transition can be defined as a timely transition towards a more inclusive, sustainable, affordable and secure energy system that provides solutions to global energy-related challenges, while creating value for business and society, without compromising the balance of the energy triangle"

Table 15.3 **Energy investment in Europe**

Europe	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total (billion $2019)	**330**	**316**	**306**	**302**	**308**	**272**
Supply (by type)	240	217	212	208	216	184
Fossil fuels (fuel supply & power)	108	86	82	79	85	59
Renewables	76	76	77	74	72	69
Electricity networks	51	49	47	48	48	45
Other supply	6	6	6	7	11	11
End-use	90	99	94	94	92	87
Energy efficiency	80	89	84	83	80	78
Renewables and other end-use	10	10	10	11	11	9
Renewables	10	10	9	10	10	9
Other end-use	1	1	1	1	2	0
Industry CCUS						
Electric vehicles	1	1	1	1	2	0
Fuels	99	78	75	70	73	50
Fossil fuels	94	74	70	65	68	46
Oil	49	34	37	39	40	26
Gas	43	37	31	24	26	19
Coal	3	3	2	2	2	1
Liquid biofuels and biogases	4	4	5	5	5	4
Biofuels	0	0	0	1	1	0
Biogases	4	4	4	4	4	4
Power	141	139	137	138	144	134
Generation	90	89	89	89	94	88
Coal	6	5	5	6	7	5
Gas and oil	7	7	7	8	10	8
Gas	5	4	4	5	7	5
Oil	3	3	3	3	3	2
Nuclear	5	5	5	6	10	10
Renewables	72	72	72	69	67	65
Battery Storage	0	1	1	1	1	1
Electricity networks	51	49	47	48	48	45
Memo: Oil & natural gas upstream	66	46	40	38	42	30

Source: IEA (2020), Investment Choices shaping our energy futures

Available funding sources in SE Europe

The pandemic phenomenon influenced considerably the steady growth path of countries in SEE Europe. Although countries in Central, Eastern, and Southeastern Europe (CESEE) have shown economic progress in the last 20 years, infrastructure and energy investment remains a key area for these regions so as to move towards a convergence path with the EU core partners.
In the context of the current health crisis and its subsequent economic consequences, support actions from EU focus mainly on the development of recovery and resilience strategy, with emphasis put on the mix of national priorities and socioeconomic objectives of EU (greening, employment, social cohesion, digital transformation). Table 15.4 presents the allocation of the EU budget within different programs, according to the assessment of national plans for energy and climate.

Table 15.4 **EU funds available to all Member States, 2021-2027, €billion**

Programme	Amount	Comments
Horizon Europe	91.0	In current prices. Includes Next Generation EU credits.
InvestEU	9.1	In current prices. Commitments both under the multi-annual financial framework (MFF) and Next Generation EU. Includes the InvestEU fund (budgetary guarantee to public and private investment) and the advisory hub (technical advice). Does not consider appropriations available to beneficiaries through implementing partners, such as the European Investment Bank.
Connecting Europe Facility • Transport • Energy	 24.1 5.8	In current prices. The commitment for transport includes the contribution transferred from the Cohesion Fund. Excludes Connecting Europe Facility Military Mobility funding for dual use infrastructure.
Recovery and Resilience Facility	360.0	In 2018 prices. Non-allocated commitments for loans. Loans for each Member State will not exceed 6.8% of its gross national income.
Technical Support Instrument	0.9	In current prices.
Programme for Environment and Climate	5.4	In current prices.
European Agricultural Fund for Rural Development	8.2	In current prices. Commitments under Next Generation EU.
Innovation Fund	7.0	Approximation: 7/10 of the allocations of ETS allowances to provide revenue to the Innovation Fund for 2021-2030 and assuming a carbon price of €20 per tonne.

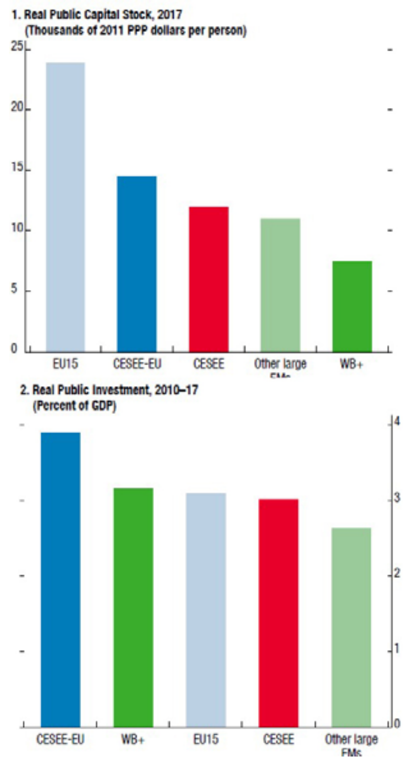
Source: Commission staff working documents, Assessment of the final national energy and climate plans

Undoubtedly, investment in energy and green infrastructure has considerable economic impact, as it affects multiple growth and social welfare indicators eg. employment prospects, socioeconomic development, transaction costs etc.

Energy investment, though it encompasses necessity for huge capital availability, economies of scale, it is also characterized by certain risks of failure and uncertainties; therefore international cooperation and financial co-integration is vital for the effective implementation of multi-annual projects. Additionally, the mobilization of private capital and appropriate project management is important for the effective execution of the planned works. At institutional level, good governance, transparency and coordination among interested countries are additional factors that promote the success' prospects of a project. As a recent study by the IMF (2020) summarizes the major potential, strengths and weaknesses of the CESEE region concerning infrastructure investment:

- A key finding is that there is significant cross-country differentiation, and CESEE countries lag behind the EU15 performance, both "in terms of public capital and various measures of physical infrastructure".
- Projections made suggest that for closing half of the current investment gap, with the EU15 countries by 2030, this might cost 3–8% of GDP annually in order to make the investment climate-resilient and green. This configuration shows that investment needs are relatively high in some of the countries in the region. Economies of scale should reach a certain level in order to achieve steady growth outcomes.
- It is also stated that better institutional governance which involves effective public investment and risk management could improve the potential of expenditure.
- The issue of cross-border cooperation is also raised in their analysis." More successful cross-border projects appear to be those with clear payoffs for individual countries, and those governed by the EU framework as a basis for transparency, adherence to international standards, better planning and greater coordination". That is, it is not the initiation of a cross-border project that promises greater economic values, but mainly the implementation of a framework which encompasses institutional principles, approved by the participants

Figure 15.3 **Capital stock and public investment, IMF (2020)**



Sources: IMF (2020), Fiscal Monitor database; and IMF staff calculations.
Note: Bars in the figure indicate the weighted average in each country group. Weights used are population (panel 1) and GDP PPP (panel 2). PPP = purchasing power parity.

Another important issue is the relation of Public capital and infrastructure stock, as it is demonstrated in the previous graph.

"The stock of public capital in per capita terms in CESEE is only about half of that of the EU15. The deficiency in CESEE's public capital stock is despite the fact that public investment rate (as percent of GDP) has remained comparable to or even exceeded that of the EU15 after the global financial crisis, reflecting the low base in CESEE's initial public capital stock".

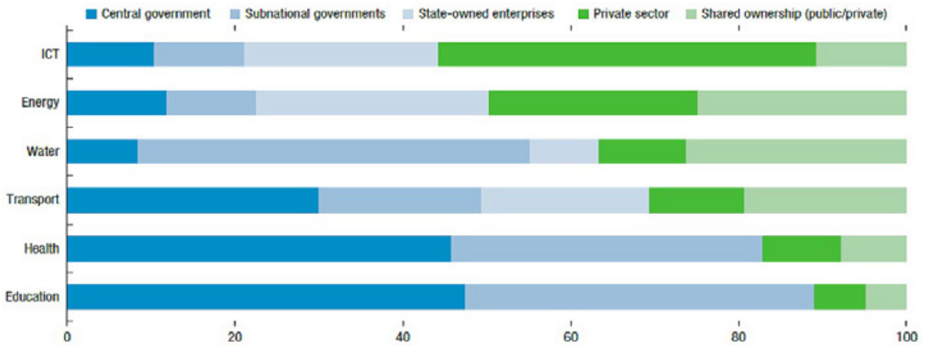
Due to the fact that private savings and institutional design as yet are not strongly present in the CESEE countries, it is important to stress that this region calls for further reform initiatives that will induce efficiency in the private and public sector investment.

Partly, such initiatives will also affect the total costs of investment in the infrastructure sector, as well as in the energy sector subsequently, which remains one of the most capital-intensive sectors on a global scale.

Table 15.5 **Infrastructure investment**

A. Comparison of CESEE Infrastructure Cost Estimates

	IMF Estimates			Beyond the Gap (World Bank)			Global Infrastructure Hub (A G20 Initiative)	Three Seas Initiative	
	A	B	C	Preferred	Low spending	High spending	Energy, telecom, transportation	Energy, telecom, transportation	
CESEE					(rescaled for CESEE)		(rescaled for CESEE)	(11 3SI members)	(rescaled for CESEE)
% of GDP/year	8.4	7.0	2.8	4.2	0.6	3.4	4.3	7.9	7.9
Total cost by 2030 (billion USD)	3670	3063	1237	1843	252	1481	1899	1291	3453



Country risk in SE Europe

The country risk factor is an important parameter which must be taken seriously into account when taking energy investment decisions. The country risk is a collection of risks associated with investing in or lending a foreign country. These risks include a composite index of political, geostrategic and economic risks, exchange rate risk, sovereign risk and transfer risk, which is the risk of capital being locked up or halted by government, for reasons related either to red tape or to administrative barriers. Table 15.6 presents how different the Country Risk is among the 15 SEE countries, while Table 15.7 defines the ratings used in Table 15.6

Table 15.6 **Country Risk in SE European Region**

Country	Moody's ratings	S&P ratings	Fitch ratings
Albania	B1(August 2019)	B+ (February 2016)	n.a.
Bosnia and Herzegovina	B3 (August 2020)	B (November 2011)	n.a.
Bulgaria	Baa1 (August 2020)	BBB (November 2019)	BBB (April 2020)
Croatia	Ba1 (November 2020)	BBB- (March 2019)	BBB- (April 2020)
Cyprus	Ba2 (September 2019)	BBB- (September 2018) 2018) 2016)	BBB- (April 2020)
Greece	Ba3 (November 2020)	BB- (October 2019)	BB (April 2020)
Hungary	Baa2 (September 2021)	BBB (April 2020)	BBB (February 2020)
Israel	A1 (April 2020)	AA- (August 2018)	A+ (April 2020)
Kosovo	n.a	n.a.	n.a.
Montenegro	B1 (March 2020)	B (March 2021)	n.a.
North Macedonia	n.a.	BB- (May 2013)	BB+ (May 2020)
Romania	Baa3 (April 2020)	BBB- (May 2014)	BBB- (May 2020)
Serbia	n.a.	BB+ (December 2019)	BB+ (March 2020)
Slovenia	A3 (October 2020)	AA- (June 2019)	A (January 2020)
Turkey	B2 (September 2020)	B+ (August 2018)	BB- (February 2020)

Source: Country Economy (2021)

15

Most countries have improved significantly compared to the ratings provided in the midst of the economic crisis in Europe. Slovenia, Bulgaria and Romania have lower country risk ratings than the rest of SE European countries, while Greece struggles to restore investors' confidence, and Turkey shows consecutive negative outlooks thanks to geopolitical tensions and strategic conflicts in the region.

Table 15.7 **Classification of Moody's, S&P and Fitch ratings**

Moody's		S&P		Fitch		
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	
Aaa	P-1	AAA	A-1+	AAA	F1+	Prime
Aa1		AA+		AA+		High grade
Aa2		AA		AA		
Aa3		AA-		AA-		
A1		A+	A-1	A+	F1	Upper medium grade
A2		A		A		
A3	P-2	A-	A-2	A-	F2	
Baa1		BBB+		BBB+		
Baa2	P-3	BBB	A-3	BBB	F3	Lower medium grade
Baa3		BBB-		BBB-		
Ba1	Not prime	BB+	B	BB+	B	Non-investment grade speculative
Ba2		BB		BB		
Ba3		BB-		BB-		
B1		B+		B+		
B2		B		B		Highly speculative
B3		B-		B-		
Caa1		CCC+	C	CCC	C	Substantial risks
Caa2		CCC				Extremely speculative
Caa3		CCC-				Default imminent with little prospect for recovery
Ca		CC				
		C				

Sustainable finance mechanisms

New international priorities for the eligibility and financing of an investment project have gained grounds, under the growing sustainability agenda, therefore financing institutions have begun to incorporate social costs and benefits arising from environmental impact analysis, or more broadly through the assessment of achieving sustainable development goals. In the past the existence of strict licensing procedures was sufficient to approve the implementation of a large investment project, if they were accompanied with high initial cost of funds and long-term returns. However, in the current market procedures the field of assessment is associated with critical parameters / conditions that a project must be able to meet sustainable development and environmental sustainability objectives.

The abbreviation ESG refers to the implementation of environmental, social and governance criteria for the assessment of an investment which has profound impact to the economy and society on an intergenerational time span.

Funds, investors, and various consortia have developed special interest on investing not only in profitable schemes but also in the maximization of social welfare and public values. ESG criteria ideally help investors to assess companies that might pose a greater financial risk due to their environmental or other practices.

The implementation of performance evaluation ESG criteria serves the more effective appraisal of the robustness of a business/ or investment/ or project governance mechanisms and its ability to effectively manage its environmental and social impacts. Examples of ESG data include the quantification of a company's carbon emissions, water consumption, energy consumption, fair trade, green efficiency, infrastructure quality for disabled, cyber security, employment perseverance or even customer privacy breaches, gender equality and human rights. Institutional investors, economic analysts, economic stakeholders, financiers, stock exchanges and BoDs of companies often use sustainability and social responsibility disclosure information to scrutinize potential linkages between a company's/ investment's/ project's management of ESG risk factors and its financial performance.

ESG investing is also referred in finance literature as sustainable investing, responsible investing, impact investing, or socially responsible investing (SRI). Subsequently, project sustainability bonds or green bonds have emerged as technical derivatives of the implementation of ESG criteria on investment analysis.

The case of green bonds development

Globally, but in Europe as well, there is a significant shift towards the deployment of financial tools and funds towards project bonds, as either uncertainty remains regarding the inability of capital markets to finance sustainable large-scale investment projects, or they fail to cooperate with government entities due to prolonged fiscal and debt crisis.

The EU-EIB Europe 2020 Project Bond Initiative aims to create the conditions for the establishment and consolidation of a bond market for infrastructure projects. The initiative invites institutional investors - low risk - to participate in large-scale investment projects of social benefit, by the European Investment Bank itself undertaking to insure part of the risk, through (a) direct contribution of reduced collateral debt, (b) provision of in-kind support guarantees / credit line to cover initial construction costs.

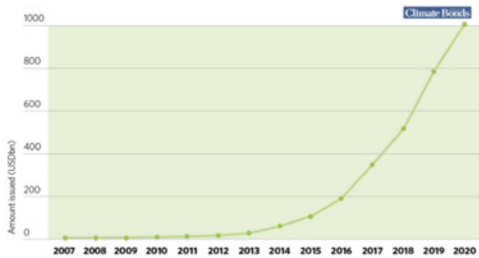
An important sub-category of project bonds are the so-called green bonds. During the last 10 years, the number of funding agencies (recipients and providers) that adopt corporate strategies and green funding tools has significantly increased, in an attempt to support the specific demand for environmental and economic sustainability.

It is statistically reported that the bond market for investment projects with an environmental footprint reached some $600 billion in total in the early period 2007-2014. In 2018, alone, the green bonds reached more than $160 billion in value showing a sharp increase (see European Commission 2018).

Figure 15.4 **Green bonds represent an incresing share of global bond issuance**

The green finance market reached its most substantial milestone, with USD 1.002 trillion in cumulative issuance since market inception in 2007, according to the Climate Bonds Green Bond Database. The milestone was passed in early December (Figure 15.5).

Figure 15.5 **The evolution of green bonds**



According to the latest data from the Climate Bond Initiative (CBI), total annual green investment (green bonds, green loans & green sukuk) reached a record $297bn in 2020. At the end of Q3 2021, green bond issuance for the calendar year stood at $354bn, surpassing last years record (Figure 15.6).

Figure 15.6 **Annual Green Bond Issuance 2015 to Q3 2021 in USD billion**

According to the EU definition, a green bond is any type of declared bond instrument that satisfies the following three conditions:

1. Investment funds shall be used exclusively for the financing or refinancing, in whole or in part, of new and / or existing eligible green projects, in accordance with the EU Environmental / Development Sustainability Classification System.
2. The bond issuance documentation confirms the alignment of the issuer of the green bond with the four dimensions of the EU green bond standard.
3. The "compliance" of the bond with the four dimensions of the EU standard should be verified by an independent and accredited external evaluator[2] .

[2] a) use / utilization of resources, b) evaluation and selection process, c) project management, d) investor information / progress reports

Green Bonds are any type of bond instrument where funds are used exclusively to finance or refinance investment projects with tangible environmental benefits which are in line with the four basic dimensions of the Green Bond Principles. Eligible green projects include renewable energy, energy efficiency, pollution prevention and control, products with ecological efficiency, circular economy, environmentally friendly technologies and production processes, ecological buildings, conservation of terrestrial and aquatic biodiversity.

By issuing a green bond, issuers signal their commitment to tackle green and environmental issues both internally and externally by funding projects with environmental benefits. They can also achieve greater diversification of the investment base, resulting in increased demand and the emergence of comparative advantages of the company, industry and geographical area in which they operate.

It is also important to stress that certain forms of state or non-state aid, licensing and / or tax incentives may also be available in certain versions, through public sector, financial sector or joint venture investment programs.

It is generally understandable that today there are several broad categories of eligibility for green projects, which contribute to specific environmental objectives such as: mitigating the effects of climate change, adapting to climate change, conservation of natural resources, conservation of biodiversity, prevention and control.

Eligible Green Investment categories include (without excluding other modern versions):

- renewable energy sources (in production, consumption, products and appliances used)
- energy efficiency (such as in new and renovated buildings, energy storage, heating, smart grids)
- pollution prevention and control (including reduction of air emissions, control of greenhouse gases, soil remediation, waste recycling and energy efficiency of waste).
- conservation of terrestrial and aquatic biodiversity (including protection of coastal areas and the catchment area)
- clean transport (such as electric, hybrid, public, rail, non-motorized, multimodal transport, infrastructure for clean energy vehicles and reduction of harmful pollutant emissions)
- sustainable water and wastewater management (including sustainable clean and / or drinking water infrastructure, wastewater treatment, sustainable urban drainage systems and river training and other forms of flood mitigation)
- adaptation to climate change (including information support systems such as climate monitoring and early warning systems)
- products, technologies and production processes with cost-effective technology and with an emphasis on the circular economy (such as the development and introduction of environmentally sustainable products with eco-label or environmental certification, packaging and high-efficiency distribution)
- green buildings that meet regional, national, or internationally recognized standards and have the necessary certifications.

For the convenience of investors, international agencies and organizations have established a code of principles for green investments, which is adopted on a voluntary basis by companies wishing to participate in green financing processes.

The Green Bonds Authority (GBP), the Green Bond Initiative (GBI) and others promote efficiency in the green bond market by introducing guidelines that promote transparency, control and accountability. With an emphasis on the efficient use of resources, the specific authorities aim to support companies to restructure their business model by taking into account environmental and development sustainability through the implementation of specific projects.

Bond issuance processes which are aligned with these principles should provide investment options with transparent green / environmental criteria. Recommending to interested issuers to submit reports on the use of funds from the issuance of the green bond, in essence, promotes a crucial shift in the business culture; it serves as a transparency mechanism that greatly facilitates the monitoring of the management of funds. Today, there are certain agencies and institutes internationally that provide independent analysis, advice and guidance / mentoring on the quality of various green interventions and friendly environmental policies, in projects with an environmental impact.

IENE participates in this process as a verifier, a licensed partner, certified by GBI to be able to assess the capacity of an applicant to be eligible to issue a green bond, thus financing his energy investments. Companies issuing green bonds should keep an up-to-date record and provide information to the investing public about the use of funds on an annual basis at least. The annual report should include a list of projects to which green investment funds have been allocated, as well as a brief description of the projects that have been implemented and the amounts that have been committed, while it would be advisable to prepare a relevant impact study. The level of transparency is particularly important for communicating about the expected impact of these investments.

15.5 Cost Assumptions for Energy Projects in SE Europe

Appraising the value of the overall energy related investment and capital expenditure for the various countries in SEE and for cross-border projects, we have examined the installation costs under each form of energy installation, whether these involve power generation from conventional and Renewable Energy Sources or the construction of gas pipeline projects or hydrocarbon exploration and production.

In these approximations, we take into account the conclusions acquired from extensive discussions and correspondence IENE had with industry representatives in selected countries in SE Europe (mainly Greece, Turkey, Serbia, Croatia, Romania and Bulgaria), and consequently we have arrived at certain assumed energy plant installation costs currently prevailing, and we undertake projections, where necessary, over the next five years. Where such costs are quoted under each country the costs have been obtained, and quoted as such, from government departments involved in approval and licensing procedure or directly.

Table 15.8 **Assumed Energy Plant Installation Costs in SE Europe (2020-2030)**

A. Power Generation

Thermal

(i) a. Lignite fired plants for capacity higher than 400 MW: € 1.8-2.2 million/MW

b. Lignite fired, for plants of capacity lower than 400 MW (i.e. 200-300 MW): € 1.0-1.4 million/MW

(ii) Gas Fired (CCP's) : € 600.000-€ 800.000/MW

(iii) Oil Fired : € 850-€ 1,700/kW

Large Hydroelectric

For plants with more than 50 MW of installed capacity : € 2.000-€ 2.500/KW > € 2.0-2.5 million/MW

Notes
- Includes all mechanical-electrical engineering work and ports
- Includes all civil engineering work (i.e. roads, dams, bridges)

Nuclear

For AES-2006 VVER pressurized water reactors in Turkey: €4 million/MW For Generation III+ pressurized water reactors in Turkey: €4.5 million/MW

For pressurized heavy water reactors (PHWR), CANDU 6 type in Romania: €4.5 million/MW

Combined Heat and Power (CHP)

(i) Combined-cycle (CCGT) CHP plant: €770.000 - 1.260.000/MWe, with a typical cost figure of €900.000/MWe. The annual Operation and Maintenance (O&M) costs are approx. €35.000/MWe.

(ii) Gas-engine CHP plant: € 600.000 - 1.400.000/MWe, with a typical cost figure of €735.000/MWe. The annual O&M costs are about €175.000/MWe.

(iii) Fluidised-bed combustion (FBC) CHP plant based on coal: €2.100.000 - €4.200.000/MWe, with a typical cost figure of €2.280.000/MWe. The annual O&M costs are approx. €70.000/MWe.

(iv) Biomass CHP plant: €2.100.000 - €4.200.000/MWe. The annual O&M cost is about €70.000/MWe.

B. Power Transmission Network

(i) Overhead Lines

Total cost per circuit route length (km), based on total asset costs, excluding financing costs: a. 380-400 kV, 2 circuit: €1.060.919

b. 380-400 kV, 1 circuit: €598.231

c. 220-225 kV, 2 circuit: €407.521

d. 220-225 kV, 1 circuit: €288.289

(ii) Underground Cables

Per route length (km)

a. 380-400 kV, 2 circuit: €4.905.681

b. 220-225 kV, 2 circuit: €3.314.047

c. 220-225 kV, 1 circuit: €2.224.630

d. 150 kV, 2 circuit: €1.511.846M e. 150 kV, 1 circuit: €695.704

All cables were AC. Insufficient data was available to assess DC cables.

(iii) Subsea Cables

Total cost per route length (km):

a. All cables types: €909.910

b. AC cables (150-220 kV): €1.143.966 c. DC cables (250-500 kV): €757.621

C. Renewable Energy Sources

(i) Wind Farms

€ 1.25 – 1.30 million/MW installed

Notes:

- Includes road works, electricity substations and transmission lines
- Average size of wind generator 3.0-3.3 MW

(ii) Solar thermal electricity

Solar Tower € 3.5 million/MW installed

Solar Combined Cycle Power : (CCP) € 1.3 million/MW

(iii) Photovoltaic plants

€ 0.9 – 1.1/W for turnkey projects

€ 1.0 million/MW installed

Notes:

- Prospects for € 0.8-0.5/W per installed MW over next 5 years
- 260W capacity per panel is assumed for normal installations

(iv) Biomass

€ 3.0 -3.5 million/MW installed

(v) Small Hydro for units up to 15MW

€ 1.000/KW ~ € 1.0 million/MW installed

Notes:

- Normally it includes only electrical/mechanical installations
- Extensive civil engineering works are not included

(vi) Geothermal (high enthalpy)

D. Natural Gas

i) Main Pipelines

€ 1.0 - 1.2 million/km for 36''-48'' diameter pipes

€ 1.4 - 1.6 million /km for 58'' diameter pipes

(ii) Branches

€ 0.70-0.75 million/ km for 26'' diameter pipes

(iii) City Grids

€80/m > €80.000/km

Notes:

- Above costs do not include compressor stations, metering stations and gas treatment plants.

E. Assumed Oil and Gas Exploration CAPEX

(i) Onshore deep drilling

$ 40 - $60 million per drilling for depths between 3.000 m to 6.000 m

(ii) Offshore drilling (swallow waters)

$ 15 - $20 million per drilling

(iii) offshore drilling (deep waters)

$ 50 - $ 60 million per drilling, for offshore deep waters up to 2.000 m in the Mediterranean.

$ 100 - $ 120 million per drilling for ultra-deep waters (more than 2.000 m), also in the Med.

(iv) Horizontal Drilling

From shore to sea $ 15.000 - $ 18.000 per drilling per day for a 60-70 days duration operation.

15.6 Energy Investment Outlook per Country and per Sector

A short assessment of the energy investment outlook of each one of the 15 countries, which this Outlook report covers, has been made and is presented in the tables which follow. This investment outlook covers a period of 10 years, i.e. 2021-2030 as it is important to be able to appreciate the long-term investment potential of the countries concerned and the region as a whole. With the danger that some of the estimates may not be that accurate, especially in the second five-year term, i.e. after 2026, it was nevertheless considered important to provide a far reaching investment outlook in the belief that this helps investors, especially institutional ones, in their search for attractive and viable investment opportunities in the region's energy sector.

What the tables which follow show is the broad energy related investment picture of the region. However, before looking at the data in the various tables, it is important to consider two important aspects which shape investment forecasts. Firstly, data and estimates are not controlled for the impact of the pandemic on the policy priorities of the various countries. Secondly, the numerical estimates of investments per energy sector are based on the investigation undertaken by IENE associates in the context of the preparation of each country profile.

Most figures are based on official government and corporate announcements involving future investments. However, in certain cases where hard information was lacking, IENE, on the basis of relevant information not necessarily originating at government or corporate level, has carried out its own independent estimates backed by its considerable experience and familiarity with the various energy activities in the various countries of the region.

ALBANIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	1,200
	Downstream	• Refining (upgrading) • Loading Terminals • Underground storage facilities • Crude / Product Pipeline(s)	300
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities • FSRU Terminal	350
ELECTRICITY	Power Generation	• Gas (including CHP) • Large Hydro	650
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	400
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	900
ENERGY EFFICIENCY		• Awareness campaigns • Energy improvement schemes for buildings	700
	Total anticipated investments by 2030		**4,500**

Name of contributor: IENE (2021)

BOSNIA-HERZEGOVINA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	100
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	200
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	400
ELECTRICITY	Power Generation	• Lignite • Coal • Gas (including CHP) • Large Hydro	4,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	400
	RES	Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	2,400
ENERGY EFFICIENCY		• Energy upgrade of buildings	2,000
	Total anticipated investments by 2030		**9,400**

Name of contributor: IENE (2021)

BULGARIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	1,500
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	500
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	2,000
ELECTRICITY	Power Generation	• Lignite • Coal • Gas (including CHP) • Nuclear • Large Hydro	10,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid • Storage facilities	14,000
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	3,000
ENERGY EFFICIENCY		• Energy upgrade of buildings	16,000
	Total anticipated investments by 2030		**47,000**

Name of contributor: IENE (2021)

CROATIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	3,300
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	1,700
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities • FSRU Terminal	2,000
ELECTRICITY	Power Generation	• Lignite • Coal • Gas (including CHP) • Nuclear • Large Hydro	2,500
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid • Storage facilities	2,500
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	2,000
ENERGY EFFICIENCY		• Energy upgrade of buildings	7,000
	Total anticipated investments by 2030		**21,000**

Name of contributor: IENE (2021)

CYPRUS

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells and associated infrastructure	8,000
	Downstream	• Loading Terminals • Storage facilities	200
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities • FSRU Terminal	800
ELECTRICITY	Power Generation	• Gas (including CHP)	1,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	200
	RES	• Small Hydro • Wind farms • Photovoltaics • Concentrating Solar Power • Biomass/ liquid biofuels	1,000
ENERGY EFFICIENCY		• Energy upgrade of buildings	5,000
	Total anticipated investments by 2030		**16,200**

Name of contributor: IENE (2021)

GREECE

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells and associated Infrastructure	4,000
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	1,800
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Small-scale LNG • Storage facilities • FSRU Terminals	2,000
ELECTRICITY	Power Generation	• Lignite • Gas • Large Hydro • Electricity Storage	4,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	5,500
	RES	• Small Hydro • Wind farms • Photovoltaics • Concentrating Solar Power • Biomass/ liquid biofuels • Geothermal	15,100
ENERGY EFFICIENCY		• Energy upgrade of buildings	12,000
	Total anticipated investments by 2030		**44,400**

Name of contributor: IENE (2021)

HUNGARY

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	800
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities	500
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Small-scale LNG • Storage facilities	1,300
ELECTRICITY	Power Generation	• Coal • Gas (including CHP) • Nuclear • Large Hydro	12,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	2,700
	RES	• Small Hydro • Wind farms • Photovoltaics • Concentrating Solar Power • Biomass/ liquid biofuels • Geothermal	6,000
ENERGY EFFICIENCY		• Electric Vehicles • Energy upgrading of buildings	2,000
	Total anticipated investments by 2030		**25,300**

Name of contributor: IENE (2021)

ISRAEL

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells and associated infrastructure	8,000
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities	800
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	2,000
ELECTRICITY	Power Generation	• Gas	1,200
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	3,500
	RES	• Small Hydro • Wind farms • Photovoltaics • Concentrating Solar Power • Biomass/ liquid biofuels • Geothermal	21,800
ENERGY EFFICIENCY		• Electric Vehicles • Energy upgrading of buildings	2,000
	Total anticipated investments by 2030		**39,300**

Name of contributor: IENE (2021)

KOSOVO

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	-
	Downstream	• Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	200
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	800
ELECTRICITY	Power Generation	• Lignite • Gas (including CHP) • Large Hydro	2,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	400
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	1,500
ENERGY EFFICIENCY		• Energy upgrading of buildings	2,500
	Total anticipated investments by 2030		**7,400**

Name of contributor: IENE (2021)

MONTENEGRO

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	500
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	100
GAS	Gas Network	• Grid development • Main intra country pipeline(s)	500
ELECTRICITY	Power Generation	• Coal • Gas (including CHP) • Large Hydro	500
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	1,000
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	1,500
ENERGY EFFICIENCY		• Electric Vehicles • Energy upgrading of buildings	500
	Total anticipated investments by 2030		**4,600**

Name of contributor: IENE (2021)

NORTH MACEDONIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	-
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	100
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	600
ELECTRICITY	Power Generation	• Lignite • Gas (including CHP) • Large Hydro	1,800
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	400
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	1,500
ENERGY EFFICIENCY		• Electric Vehicles • Energy upgrading of buildings	6,000
	Total anticipated investments by 2030		**10,400**

Name of contributor: IENE (2021)

ROMANIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	10,000
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	2,000
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	2,600
ELECTRICITY	Power Generation	• Coal • Gas (including CHP) • Nuclear • Large Hydro	8,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid • Storage facilities	2,500
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	20,000
ENERGY EFFICIENCY		• Electric Vehicles • Energy upgrading of buildings	5,000
	Total anticipated investments by 2030		**50,100**

Name of contributor: IENE (2021)

SERBIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	600
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	1,400
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities	2,400
ELECTRICITY	Power Generation	• Lignite • Coal • Gas (including CHP) • Large Hydro	3,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	1,000
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	1,800
ENERGY EFFICIENCY		• Energy upgrading of buildings	5,000
	Total anticipated investments by 2030		**15,200**

Name of contributor: IENE (2021)

SLOVENIA

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	-
	Downstream	• Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	200
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities • Pilot projects (synthetic fuels and hydrogen)	400
ELECTRICITY	Power Generation	• Gas (including CHP) • Nuclear • Large Hydro	500
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	4,600
	RES	• Small Hydro • Wind farms • Photovoltaics • Biomass/ liquid biofuels • Geothermal	1,400
ENERGY EFFICIENCY		• Energy upgrading of buildings	5,000
	Total anticipated investments by 2030		**12,100**

Name of contributor: IENE (2021)

TURKEY

	Project sector	Description	Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	9,000
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)	200
GAS	Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities • FSRU Terminal	7,000
ELECTRICITY	Power Generation	• Gas (including CHP) • Nuclear • Large Hydro	40,000
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid	20,000
ELECTRICITY	RES	• Small Hydro • Wind farms • Photovoltaics • Concentrating Solar Power • Biomass (including liquid biofuels) • Geothermal	30,000
ENERGY EFFICIENCY		• Energy upgrading of buildings	5,000
	Total anticipated investments by 2030		**12,100**

Name of contributor: IENE (2021)

15.7 Cross Border Energy Projects

A significant amount of forthcoming investment and the identification of energy related business opportunities is associated with a number of key cross-border energy projects, a small number of which are already in the implementation stage, whereas others, the great majority, are at an advanced planning stage. These projects cover gas pipelines, both interconnectors and major transnational projects, but also cross-border high-voltage electricity transmission lines. Tables 15.9 and 15.10 summarize these projects together with their estimated construction costs.

The total anticipated expenditure for all projects listed in Tables 15.9 and 15.10 amounts to €31,743 billion for a best case scenario. However, it should be made clear that not all of these projects are ever likely to be implemented as such.

Table 15.9 **Gas Transnational Projects in SE Europe**

Project Name	Size	Unit	Status	Value (€mn)
Alonian Adriatic Pipeline Project (Albania - Montenegro - BiH - Croatia)	5	bcm/year	Under study	620
Gas Interconnection Pipeline BiH - Croatia (Slobodnica-Bosanski Brod-Zenica)	5	bcm/year	Planning stage	94
Interconnection Pipeline BiH - Croatia (Zagvozd - Posušje - Novi Travnik with a main branch to Mostar) and Interconnection Pipeline BiH - Croatia (Ploce - Mostar - Sarajevo/Zagvozd - Posušje/Travnik)	1.5-2.5	bcm/year	Planning stage	98
Interconnection Pipeline BiH - Croatia (Licka Jesenica-Trzac-Bosanska Krupa)	1.0-1.5	bcm/year	Planning stage	49
Gas Interconnector Greece-Bulgaria (IGB), Komotini (Greece) - Stara Zagora (Bulgaria)	150	km	Under construction	220
Malkoclar (Kirklareli, Turkey) - Lozenetz (Bulgaria) Gas Interconnector ITB Project	75	km	Feasibility study is ongoing	105
Eastring Gas Pipeline Project	40	bcm/year	Under consideration	2,000
Bulgaria - Romania - Hungary - Austria Gas Interconnector Project	6	bcm/year	Under construction	500
Interconnector Greece-Italy (IGI Onshore and Poseidon) Gas Pipeline Project	12	bcm/year	Planning stage	1,100
Interconnection Pipeline Serbia (Nis-Dimitrovgrad) to Bulgaria	1.8	bcm/year	Planning stage	115
Nagykanizsa - Tornyiszentmiklos (Hungary) - Lendava - Kidricevo (Slovenia) Pipeline	115	km	Planning stage	110
Tesla Pipeline Project	27	bcm/year	Under consideration	4,500
East Med Gas Pipeline	15	bcm/year	Under study	12,000
Albania-Kosovo Gas Pipeline	2	bcm/year	Under study	610
Gas Pipeline Skopje - Tetovo - Gostivar - Albanian border	25	GWh/d	Under study	231
Gas Interconnection Pipeline North Macedonia - Albania (Kichevo-Ohrid-Struga-Kafasan)	1	GWh/d	Under study	105
Gas Interconnection Pipeline North Macedonia - Greece (Stojakovo village/Pontoiraklia to Nea Messimvria)	76.5	GWh/d	Under study	200
Gas Interconnection Pipeline North Macedonia - Bulgaria	110	km	Under study	23
Gas Interconnection Pipeline Croatia - Serbia (Slobodnica/Sotin - Backo Novo Selo)	87	km	Under study	143

Gas Interconnection Pipeline Romania - Serbia	85	km	Under study	54
Gas Interconnection Pipeline BiH - Serbia	102	km	Under consideration	45
Gas Interconnection Pipeline Croatia - Slovenia (Lucko-Zabok-Rogatec)	69	km	Under study	97
Gas Interconnection Pipeline Croatia - Slovenia (Umag - Koper)	8	km	Under study	11
Gas Interconnection Pipeline Italy - Slovenia (Gorizia - Ajdovscina/Sempeter)	31	km	Under study	43
Gas Interconnection Pipeline Kosovo - North Macedonia	1	bcm/year	Under study	110
Gas Interconnection Pipeline Serbia - North Macedonia	42	km	Under consideration	20
Gas Interconnection Pipeline Kosovo - Serbia	1	bcm/year	Under study	100
Total Estimated Cost				**23,303**

Sources: IENE, Energy Community, ENTSO-G

Table 15.10 **Electricity Transmission Interconnectors in SE Europe**

	Size	**Unit**	**Status**	**Value (€mn)**
Albania - North Macedonia	400	kV	Under construction	81
BiH - Croatia	440	kV	Under study	160
BiH - Serbia	400	kV	Under study	58
Bulgaria - Greece	400	kV	Under construction	224
Bulgaria - Romania	400	kV	In permitting phase	196
Bulgaria - Turkey	400	kV	Under study	60
Croatia - Serbia	400	kV	Under study	19
Hungary - Serbia	400	kV	Under study	65
Hungary - Romania	400	kV	Under study	200
Greece - Italy	400	kV	Under study	2,400
Greece-Turkey	400	kV	Under study	33
Montenegro - Serbia	400	kV	Under study	58
Romania - Serbia	400	kV	In permitting phase	189
Serbia - Albania	400	kV	Under study	58
Italy - Slovenia (Redipuglia-Vrtojba and Dekani-Zaule)	400	kV	In permitting phase	40
Italy - Slovenia (Divaca - Bericevo and Salgareda)	400	kV	In permitting phase	755
EuroAsia Interconnector (Greece - Cyprus - Israel)	500	kV	In permitting phase	3,844
Total Estimated Cost				**8,440**

Sources: IENE, Energy Community, ENTSO-E

15.8 Total Investment Estimates

The total energy investment estimate for the region amounts to approx. €437 billion for the period 2021-2030 is presented on a country-by-country basis in Table 15.11. By adding the total country and cross border project's estimated investment costs (Tables 15.9 and 15.10), which stand at €31.7 billion, we arrive at a global investment estimate for the entire region. On the basis of information presented in this chapter, the global investment estimate for the 15-country group in SE Europe stands at about €483.4 billion. This compares to €273 billion of Scenario A and €333 billion of Scenario B, as reported in the SEEEO study of 2016/2017 published in 2017, and indicates a much higher investment potential level for the entire region.

Even if we are to exclude Hungary and Israel, which were not part of the SEE 2026/2017 report, the total corresponding investments for the 13-country group amount to €387,1 billion. A number which is much higher in Scenario B (in the 2017 SEEEO publication). If we are to consider just Scenario A (corresponding to stated policies), we are talking about an increase of + €114,0 billion of anticipated investments over the 10-year period. This is a vast improvement compared to five years ago and indicates the region's increased attractiveness as an energy investment destination. Anticipated investments show an increase by 41.8% for the 13-country group compared to estimates complied 5 years ago.

Table 15.11 **Total Anticipated Energy Investment per Country for 2021-2030**

Country	Estimated Investment (mn €) 2021 Estimate	Estimated Investment (mn €) 2017 Estimate	GDP growth 2021 (%) IMF World Economic Outlook	GDP growth annual projection to 2025 (%)
Albania	4,500	7,460	5.3	3.5-4.5
Bosnia & Herzegovina	9,400	8,722	2.8	3-3.2
Bulgaria	47,000	11,050	4.5	3.1-4.5
Croatia	21,000	8,525	6.3	3.2-5.8
Cyprus	16,200	7,350	4.8	2.7-3.6
Greece	44,400	23,300	6.5	1.5-4.6
Hungary	25,300	-	7.6	2.6-5.1
Israel	39,300	-	7.1	3.2-4.1
Kosovo	7,400	2,605	4.8	n/a
Montenegro	4,600	2,400	7.0	2.9-5.6
North Macedonia	10,400	3,400	4.0	3.6-4.2
Romania	50,100	20,630	7.0	3.6-4.8
Serbia	15,200	11,260	6.5	4.0-4.5
Slovenia	12,100	3,185	6.3	2.9-4.6
Turkey	130,000	124,935	9.0	3.3
Total	**436,900**	**234,822**		

NB. Hungary and Israel were not included in the 2017 SEE Country Survey and hence no estimates have been prepared by IENE.

15

Table 15.12 **Total Anticipated Energy Investment per Sector for 2021-2030**

	Project sector	Description	2021 Investment estimate (€ mn)	2017 Investment estimate (€ mn)
OIL	Upstream	• Field Exploration • Development of new oil and gas wells	63,000	38,790
	Downstream	• Refining (upgrading) • Loading Terminals • Storage facilities • Crude / Product Pipeline(s)		
GAS	Country Gas Network	• Grid development • Main intra country pipeline(s) • Storage facilities • FSRU and LNG Terminals	25,150	16,550
ELECTRICITY	Power Generation	• Lignite • Coal • Gas (including CHP) • Nuclear • Large Hydro	150,150	139,550
	Electricity Grid	• New H/V transmission lines • Upgrading and expansion of existing grid		
	RES	• Small Hydro • Wind farms • Photovoltaics • Concentrating Solar Power • Biomass (including liquid biofuels) • Geothermal	109,900	40,009
ENERGY EFFICIENCY		• Buidings • Industry • Electric vehicles	88,700	-
	Total anticipated investments by 2030		436,900	234,822
	Gas infrastructure		23,303	33,350
	Electricity Interconnections		8,440	4,700
	Cross-border energy projects (total)		**31,743**	**38,050**
	Grand Total		468,643	272,872

*(1) This estimate refers to Scenario A as stated in SEE Energy Outlook 2016/2017, p. 1123-1124.
(2) No investment estimates for Energy Efficiency applications were provided in the SEE Energy Outlook 2016/2017.

15.9 Business opportunities

An analysis of the planned energy investments in the SEE region, as shown in Table 15.12, inform us that the bulk of the anticipated investments are to be found in the electricity sector, which covers power generation plants, electricity transmission lines and distribution grids. Electricity infrastructure projects lead the way with substantial new investments reported by almost all countries. These include the construction of new power generation stations (i.e. thermal, hydro, nuclear and RES), maintenance and upgrading of existing ones, new HV transmission lines, electricity grid extension and coal mine development.

The electricity-oriented investments correspond to approx. 34% of the total energy investments in the region at €150 billion. Following electricity investments are the RES related investments corresponding to 25% of the total at about €110 billion. Thus, electricity and RES form the backbone of investment activity in the region's energy market and it is in this area that new business opportunities are mainly to be found.

Third in line in terms of funding needs is energy efficiency, corresponding to 20% at €88.7 billion. The investment prospects in this area appear much improved compared to the estimations of the 'SEE Energy Outlook 2017'. In fact, this is a fast growing business with building renovation for improved thermal performance being a core activity. Back in 2017, when the second SEEE Outlook was published, there appeared to be limited activity. So, 'energy efficiency' has grown exponentially in investment terms over the last 5 years.

Following that, a 14% at €63 billion corresponds to hydrocarbon investments, with the majority in the upstream sector. While natural gas fares lowest at 6.0% of the total anticipated investments at €25.1 billion, with the bulk of the funds channeled to major gas pipeline projects and LNG facilities.

Oil and gas oriented investments stand at the lower level of total anticipated energy investments in SE Europe, mainly due to the downturn experienced over the last two years in oil and gas exploration on account of the coronavirus pandemic and changes in strategic investment plans of major oil and gas companies. Therefore, in terms of planned investments, mainly in the upstream sector, activity has generally slowed down. This, among others, reflects the change of priorities by governments and companies as more and more attention is being paid to electricity related projects which appear to lead the way in the new energy transition era.

Appendix

Energy funding in EU SEE Countries

The multiannual framework of EU for the period 2021-2027 do not only entail public expenditures for investments and social policy as it usually occurred in the previous period, but also includes several actions associated with the mobilization of funds towards climate change mitigation and development of green economy. In the following tables, there is a short description of available EU funds, according to national plans. Partially, these funds will be devoted to combat climate crisis and improve environmental standards, access to energy and green efficiency on EU countries.

BULGARIA

Table 15.13 **EU funds available, 2021-2027: commitments, EUR billion**

Programme	Amount	Comments
Cohesion policy funds (ERDF, ESF+, Cohesion Fund)	98	In current prices. Includes funding for European territorial cooperation (ETC). Does not include amounts transferred to the Connecting Europe Facility.
Common agricultural policy – European Agricultural Fund for Rural Development, and direct payments from the European Agricultural Guarantee Fund.	98	In current prices. Commitments under the multi-annual financial framework.
Recovery and Resilience Facility	60	In 2018 prices. Indicative grants envelope, sum of 2021-2022 and estimated 2023 commitments. Based on the Commission's summer 2020 GDP forecasts.
Just Transition Fund	12	In 2018 prices. Commitments both under the multi-annual financial framework (MFF) and Next Generation EU.
Modernisation Fund	03	Approximation: 7/10 of the allocations of ETS allowances to provide revenue to the Modernisation Fund tentatively allocated to Member States for 2021-2030 and assuming a carbon price of EUR 20 per tonne.
ETS auction revenue	28	Indicative: average of actual 2018 and 2019 auction revenue, multiplied by seven. The amounts in 2021 to 2027 will depend on the quantity and price of auctioned allowances.

Source: Commission staff working documents, Assessment of the final national energy and climate plans

Major infrastructure projects

- Construction of a new dual 400 kV interconnecting power line between Bulgaria and Serbia

The project has been included as a new investment in the last ENTSO-E ten-year network development plan 2018.

- Construction of a new 400 kV power line between Bulgaria and Turkey.
- Construction of new 400 kV internal power lines between the Vetren switchyard and Blagoevgrad substation and between Tsarevets substation and Plovdiv substation.
- Upgrade and expansion of elements of the internal electricity distribution network and management systems with a view to increasing the efficiency, flexibility and security of supply;
- Connecting new low-voltage and zero-emission sources of energy to the grid.

During the period 2021-2030 total investment needs under the basic scenario of national energy plan amounts EUR 42.7 billion — a figure that overexceeds the estimates for achieving the targets under the WEM scenario over the same period by EUR 240 million. This amount represents the investments needed in consumer sectors (industry, transport, services, households, etc.) and the need for investment in the sectors of electricity and heat generation in Bulgaria as shown in the table below.

Table 15.14 **Total investment costs under WAM scenario, million EUR**

	2021-2025	2026-2030	2021-2030
Consumption sectors			
Industry[24]	1 172.38	924.4	**2 096.78**
Households	5 523.30	6 308.62	**11 831.92**
Services	2 216.95	2 023.33	**4 240.28**
Transport	3 677.95	5 365.29	**9 043.24**
Non-energy consumption	141.66	91.84	**233.50**
Total	**12 732.24**	**14 713.48**	27 445.72
Generation of electricity and heat			
Electricity plants	1 141.50	11 780.01	**12 921.51**
Cogeneration plants and	92.08	56.06	**148.14**
Storage facilities		620	**620.00**
Power to X		3.45	**3.45**
Investments in grid	747.99	839.04	**1 587.03**
Total — generation of electricity and heat	1 981.57	13 298.56	**15 280.13**
Total	14 713.81	28 012.04	42 725.85

CROATIA

Table 15.15 **EU funds available, 2021-2027: commitments, EUR billion**

Programme	Amount	Comments
Cohesion policy funds (ERDF, ESF+, Cohesion Fund)	8.7	In current prices. Includes funding for European territorial cooperation (ETC). Does not include amounts transferred to the Connecting Europe Facility.
Common agricultural policy – European Agricultural Fund for Rural Development, and direct payments from the European Agricultural Guarantee Fund.	4.7	current prices. Commitments under the multi-annual financial framework.
Recovery and Resilience Facility	6.0	In 2018 prices. Indicative grants envelope, sum of 2021-2022 and estimated 2023 commitments. Based on the Commission's summer 2020 GDP forecasts.
Just Transition Fund	0.2	In 2018 prices. Commitments both under the multi-annual financial framework (MFF) and Next Generation EU.
Modernisation Fund	0.2	Approximation: 7/10 of the allocations of ETS allowances to provide revenue to the Modernisation Fund tentatively allocated to Member States for 2021-2030 and assuming a carbon price of EUR 20 per tonne.
ETS auction revenue	0.5	Indicative: average of actual 2018 and 2019 auction revenue, multiplied by seven. The amounts in 2021 to 2027 will depend on the quantity and price of auctioned allowances.

Source: Commission staff working documents, Assessment of the final national energy and climate plans
*Currency exchange rate: HRK= 0,13EUR

In the next ten-year period, HEP-DSO plans to invest funds in the amount of HRK 6,696,197,000, of which it is planned to invest in energy facilities as follows:

- investments in 110 kV energy facilities HRK 1,227,481,000
- investments in 35 kV energy facilities HRK 602,610,000
- investments in 10 kV and 20 kV energy facilities HRK 1,771,766,000
- investments in low-voltage facilities HRKJ 656,895,000
- investments in Smart grid pilot projects (co-financing from EU funds) HRK 233,745,000

The following table provides an overview of the financial resources invested in Smart grid pilot projects:

No.	Type of Investment	Total 10Y 2019-2028
1	Advanced metering infrastructure	90,918,000
2	Development and optimization of conventional network	40,618,000
3	Distribution grid automation	102,209,000
	Total	**233,745,000**

Regarding additional new interconnectors, at the level of ENTSO-E, the possibility and justification of the construction of the following lines are currently analysed:

- 400 kV transmission line Đakovo (Republic of Croatia) – Tuzla (Bosnia and Herzegovina);
- 400 kV transmission line Đakovo (Republic of Croatia) – Gradačac (Bosnia and Herzegovina);
- 400 kV transmission line Žerjavinec/ Drava (Republic of Croatia) – Heviz 2 (Hungary);
- 400 kV transmission line Ernestinovo (Republic of Croatia) – Sombor (Republic of Serbia).

Taking into account the expected accelerated integration of RES and projected energy transition with a view to reducing greenhouse gas emissions, the electricity transmission grid development should be determined taking into account the following:

- peak load at the level of transmission grid level is planned in the amount of around 2900 MW in 2020 and around 3200 MW in 2030,
- as regards possible development scenarios, the construction and connector to 110 kV grid of a new HPP (power of ~36 MW) is planned in 2024, connector to 220 kV grid (400 kV) of another HPP (power of ~380 MW) is planned in 2026, and the construction and connector to 110 kV grid of a new pumped-storage HPP (power of ~150 MW) is planned in 2028,
- as regards possible development scenarios, the entry into operation of a new CCGT block of 150 MW in the Zagreb area in 2023 and the construction of new gas blocks/block of 300 MW in 2028 are planned,
- construction of a total of 1364 MW - 1634 MW in wind farms, which represents an increase compared to the existing construction of wind farms from 788 MW to 1,058 MW,
- construction of a total of 144 MW to 387 MW in solar power plants connected to the transmission grid,
- remain in the TPP Plomin 2 until the observed period, and continue to take over the half of the production of NPP Krško.

Table 15.16 show an estimate of total investment for the period 2021-2030 as well as for the period 2021-2030.

Table 15.16 **Estimation of total investments for the years 2021 - 2030**

HRK billions	**2021 – 2030**
Electricity generation	16.32
Transmission of electricity	7.90
Electricity distribution	10.0
Heating	0.60
Solar thermal systems	3.04
Natural gas transportation and distribution	10.7
Oil sector	13.0
Hydrocarbon prospecting	24.3
Building sector- energy renovation of buildings	13.06
Building sector- nZEB new construction	38.26
Infrastructure of alternative energy forms in transport	0.57
Production of advanced biofuels	3.73
Total	**141.47 bn HRK (in 18,85 € approximately)**

Largest investments are expected in installations for electricity production (the major part of which will be investments in installations using renewable energy sources) and in the building sector, namely the construction of buildings and houses with nearly zero-energy consumption. In terms of the necessary incentives, the greatest need will be in the energy renovation of the existing building stock.

Table 15.17 **EU funds available, 2021-2027: commitments, EUR billion**

Programme	Amount	Comments
Cohesion policy funds (ERDF, ESF+, Cohesion Fund)	20.4	In current prices. Includes funding for European territorial cooperation (ETC). Does not include amounts transferred to the Connecting Europe Facility.
Common agricultural policy – European Agricultural Fund for Rural Development, and direct payments from the European Agricultural Guarantee Fund.	18.6	In current prices. Commitments under the multi-annual financial framework.
Recovery and Resilience Facility	16.2	In 2018 prices. Indicative grants envelope, sum of 2021-2022 and estimated 2023 commitments. Based on the Commission's summer 2020 GDP forecasts.
Just Transition Fund	0.8	In 2018 prices. Commitments both under the multi-annual financial framework (MFF) and Next Generation EU.
ETS auction revenue	3.6	Indicative: average of actual 2018 and 2019 auction revenue, multiplied by seven. The amounts in 2021 to 2027 will depend on the quantity and price of auctioned allowances.

Source: Commission staff working documents, Assessment of the final national energy and climate plans

The majority of the Aegean islands (Crete, rest of the Cyclades islands, Dodecanese islands, NE Aegean) will be interconnected with the Hellenic Electricity Transmission System (HETS) in the period 2020-2030. The interconnections already launched by ADMIE and/or its affiliates include:

- the completion of the interconnection of the Cyclades islands
- the interconnection of Crete (Phases I and II)
- the interconnection of the Dodecanese islands
- the interconnection of the North Aegean islands.

The Development Plan of the National Natural Gas System (NNGS), drawn up by DESFA for the period 2020-2029, sets out and proposes, among others, the following NNGS development projects:

- Compression station at Kipi.
- The Metering/Regulation station at Komotini.
- The Compression station at Ambelia.
- Upgrading of the Compression Station at N. Mesimvria.
- The Metering/Regulation station at N. Mesimvria for the connection of the NNGS with TAP.
- The Nea Mesimvria-Idomeni/Gevgeli pipeline and Metering/Regulation station.
- The pilot (first) liquefied natural gas tanker loading station.
- The new Small Scale LNG pier at the Revythousa Terminal.

According to the national plan, the expected investments are likely to contribute significantly both to national economy and to the protection of consumers from price fluctuations in energy products, through the reinforcement of competition in energy markets. The table below shows the basic scenario investment on energy sector.

Table 15.18 **Estimation of investments in the key areas of the National Energy and Climate Planning.**

Sector	**Total estimated investments (€ million for the period 2020- 2030**
1. Electricity generation from RES	9,000
2. Electrical system infrastructure	5,500
3. New thermal electricity generation plants and central storage plants	1,300
4. Works for the development of an electricity distribution network – Digitisation	3,500
5. Cross-border natural gas pipelines	2,200
6. Natural gas networks and storage	2,000
7. Research and innovation	800
8. Energy efficiency	11,000
9. Investments in the refinery sector	1,500
10. Climate change, flood management, forests	2,000
11. Circular economy, recycling	5,000
Total	**43,800**

HUNGARY

Table 15.19 **EU funds available, 2021-2027: commitments, EUR billion**

Programme	**Amount**	**Comments**
Cohesion policy funds (ERDF, ESF+, Cohesion Fund)	21.7	In current prices. Includes funding for European territorial cooperation (ETC). Does not include amounts transferred to the Connecting Europe Facility.
Common agricultural policy – European Agricultural Fund for Rural Development, and direct payments from the European Agricultural Guarantee Fund.	11.7	current prices. Commitments under the multi-annual financial framework.
Recovery and Resilience Facility	6.3	In 2018 prices. Indicative grants envelope, sum of 2021-2022 and estimated 2023 commitments. Based on the Commission's summer 2020 GDP forecasts.
Just Transition Fund	0.2	In 2018 prices. Commitments both under the multi-annual financial framework (MFF) and Next Generation EU.
Modernisation Fund	0.3	Approximation: 7/10 of the allocations of ETS allowances to provide revenue to the Modernisation Fund tentatively allocated to Member States for 2021-2030 and assuming a carbon price of EUR 20 per tonne.
ETS auction revenue	1.6	Indicative: average of actual 2018 and 2019 auction revenue, multiplied by seven. The amounts in 2021 to 2027 will depend on the quantity and price of auctioned allowances.

Source: Commission staff working documents, Assessment of the final national energy and climate plans
*Currency exchange rate: HRK= 0,13EUR

Table 15.20 **EU funds available, 2021-2027: commitments, EUR billion**

Programme	Amount	Comments
Cohesion policy funds (ERDF, ESF+, Cohesion Fund)	29.2	In current prices. Includes funding for European territorial cooperation (ETC). Does not include amounts transferred to the Connecting Europe Facility.
Common agricultural policy – European Agricultural Fund for Rural Development, and direct payments from the European Agricultural Guarantee Fund.	20.6	current prices. Commitments under the multi-annual financial framework.
Recovery and Resilience Facility	13.8	In 2018 prices. Indicative grants envelope, sum of 2021-2022 and estimated 2023 commitments. Based on the Commission's summer 2020 GDP forecasts.
Just Transition Fund	1.9	In 2018 prices. Commitments both under the multi-annual financial framework (MFF) and Next Generation EU.
Modernisation Fund	3.0	Approximation: 7/10 of the allocations of ETS allowances to provide revenue to the Modernisation Fund tentatively allocated to Member States for 2021-2030 and assuming a carbon price of EUR 20 per tonne.
ETS auction revenue	5.1	Indicative: average of actual 2018 and 2019 auction revenue, multiplied by seven. The amounts in 2021 to 2027 will depend on the quantity and price of auctioned allowances.

Source: Commission staff working documents, Assessment of the final national energy and climate plans

The main projects included in the Development Plan for the National Natural Gas Transmission System for the period 2019-2028 are68 the following:

Table 15.21 **Major investment projects**

Project	Description	Value	Timeline
1)Development of the National Natural Gas Transmission System within the territory of Romania on the Bulgaria–Romania–Hungary–Austria Corridor	The project is purposed to create a natural gas transmission capacity between the interconnection points between the Romanian natural gas transmission system and the Hungarian and Bulgarian ones.	557,4 mn €	2020 for Stage I and 2022 for Stage II
2) Development of the Southern Transmission Corridor within the territory of Romania to take over natural gas from the Black Sea shore	The major objective of this investment consists in building a telescopic natural gas transmission pipe, which connects the available natural gas resources on the Black Sea shore to the Bulgaria- Romania-Hungary-Austria corridor	360.4	2021
3) Interconnecting the National Natural Gas Transmission System with the international natural gas transmission pipe T1	Its implementation will culminate with a transmission corridor between the markets in Greece, Bulgaria, Romania and Ukraine considering that the new interconnection between Greece and Bulgaria is achieved	77,7	Expected in 2020
4) Developments of the NTS in North-East Romania in order to improve the natural gas supply in the area and to secure the transmission capacities to the Republic of Moldova	Improve natural gas supply in the north-east region of Romania and exploit network opportunity provided by the new interconnection pipe between Romania and the Republic of Moldova	174.2	2021
5) Upgrading the bidirectional natural gas transmission corridor Bulgaria- Romania-Hungary-Austria (BRHA stage 3)	SNTGN Transgaz SA planned to develop the central corridor which practically follows the route of certain pipes in the current system	530	2025
6) Project regarding new developments of the NTS in order to take over the natural gas in the Black Sea	SNTGN Transgaz SA intends to extend the NTS in order to create an additional point for collection of the natural gas extracted from the marine exploitation perimeters of the Black Sea.	9.14	2021
7) Interconnection between the National Natural Gas Transmission System in Romania and the natural gas transmission system in Serbia	The assessed option for exporting natural gas to Serbia is to take over natural gas from the future BRHA pipeline (stage I). The closest point of the BRHA pipeline to the border between Romania and Serbia is Petrovaselo Locality in Timiș County.	53.8	2020
8) Upgrading of Isaccea 1 GMS and of Negru Vodă 1 GMS	The project "Upgrading of the Isaccea 1 GMS and of Negru Vodă 1 GMS" consists in building two new natural gas measurement stations on the premises of the existing measurement stations	26.7	2021
9) Interconnection between the national natural gas transmission system and the natural gas transmission system in Ukraine on the Gherăești-Siret route	This project aims at enhancing interconnection of the national natural gas transmission network with the European transmission network.	125	2025

References

(1) IENE Study, "S.E. Europe Energy Outlook 2017", Athens, 2017

(2) IENE Study, S.E. Europe Energy Brief- Market Watch, No. 335, April 2021

(3) IENE Newsletter, "S.E. Europe Energy Brief- Market Watch", No 334, March 2021

(4) IENE, Energy Institute of South-eastern Europe. The Greek energy sector. Annual report 2019

(5) Alpha Bank, Sectors in Focus, Energy, April 2020

(6) EBRD, "Regional Economic Prospects in EBRD Countries of Operations", May 2016

(7) EIB, "The Europe 2020 Project Bond Initiative - Innovative infrastructure financing", July 2016

(8) EIB, "Wind of change: Investment in Central, Eastern and South Eastern Europe, September 2017

(9) EIB Group survey on investment and investment finance 2020, CESEE overview

(10) European Commission, "Assessment of the draft National Energy and Climate Plan 2021-2030. June 2019

(11) European Commission, "Action Plan: Financing Sustainable Growth", 8 March 2018 The Final Report, published in January 2018 is available at https://ec.europa.eu/info/sites/info/files/180131-sustainable-finance-final-report_en.pdf

(12) https://ec.europa.eu/info/publications/sustainable-finance-technical-expert-group_en

(13) European Commission, "Directive 2009/28/EC on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC"

(14) European Commission, "National Energy and Climate plans", 2021

(15) European Investment Bank, EIB Group survey on investment and investment finance 2020, CESEE Overview 2020

(16) IMF (2016), "Central, Eastern, and Southeastern Europe: How to Get Back on the Fast Track", Regional Economic Issues, https://www.imf.org/external/pubs/ft/reo/2016/eur/eng/pdf/rei0516.pdf

(17) IMF (2020), "Infrastructure in Central, Eastern, and Southeastern Europe : benchmarking, macroeconomic impact,and policy issues, European Department Fiscal Affairs Department

(18) IMF, "World Economic Outlook", Update, March 2021

(19) Investopedia (2021), "Country Risk", http://www.investopedia.com/terms/c/countryrisk.asp

Country Economy (2021), "Sovereign Ratings List", http://countryeconomy.com/ratings

(20) National renewable energy action plan in the scope of directive 2009/28/EC. Ministry of Environment, Energy and Climate Change

(21) National Greek Plan for Energy and Climate. Ministry of Environment and Energy. November 2019

(22) World Economic Forum, Fostering Effective Energy Transition, April 2021 edition

(23) World Energy Markets Observatory, 2019 Report

16

Key Messages

Key Messages

- The grouping of the 15 countries examined in the current Outlook under the SE Europe heading is more **geographically driven** than energy related. The group consists of EU Member States, the Energy Community Contracting Parties (mainly West Balkans), Turkey and Israel. Although culturally, politically and economically diverse, these countries are related and also bound, in different degrees each, to EU energy policies, strategies and objectives. Hence, the EU and its various bodies (i.e. Energy Community, ACER, CESEC, etc.) exert considerable influence in energy policy formulation and energy market operation in SE Europe.

- A review of EU energy strategy and pursued policies, and how these apply to the SE European country grouping, has revealed **considerable divergence** between stated assumptions and objectives and actual progress on the ground. What is perhaps the single most important contribution of this review is the painful realization of the conflicting points of view between EU energy planners and SEE countries' priorities when it comes to the development of indigenous energy sources. In several countries in the region (but not all) there is a clear bias towards coal/lignite, rather than RES and the introduction of energy efficiency schemes. The hierarchy agreed and followed by a number of countries at national energy policy level is strictly determined by economic and energy security considerations and gives credence to solid fuels, in spite of GHG commitments and the overall EU Climate Change policy direction.

- The EU should continue to support the collaboration between countries in the region, maintaining a strong focus on **regional energy cooperation** as a key element in the integration process. Energy can indeed become a force of co-operation and cohesion rather than conflict.

- A key element in boosting intra-regional energy cooperation lies in the **settlement of bilateral disputes** (e.g. Kosovo-Serbia, Bosnia-Herzegovina, the Greece-Turkey rift over EEZ etc). Conflict settlement and transformation efforts must continue without interruption, in order to ensure that they do not hamper cooperation in the region and do not have a negative effect on the accession process in the case of West Balkans.

- The **coronavirus pandemic** (COVID-19) led governments all over the world to impose unprecedented containment measures on transportation and economic activity in general. Combined with a fall in global oil prices, especially during March-May 2020, this crisis is producing imbalances in the energy sector, affecting both investments and the transition to decarbonisation. The plunge in carbon prices, as a result of lower energy demand, indicates the obstacles that were caused by the coronavirus spread and may affect the European Green Deal.

- The SE European countries have considerable potential to develop their economies and improve their energy efficiency by increasing and diversifying their mix of renewable energy technologies. To harness this potential and progressively phase out fossil fuels, the region needs **updated renewable energy targets**, sustained investment in solar and wind technologies, incentives to develop modern biomass, geothermal and small hydro and a holistic policy framework to create new jobs and maximise socio-economic value.

- Although the economies of the SEE region appear widely divergent in terms of structure and level of development, they share a number of challenges, which appear to be common to all. Chief among them is the priority they all give to the development of the energy sector both in terms of

infrastructure and market operation. This can be clearly seen in the analysis of forecasted investments in the energy sector by 2030 which are much higher than those estimated 5 years ago.

- The SEE region's **energy mix** is still characterized by glacial change in terms of differentiation of the dominant fuels. In spite of the significant rise of RES in most countries and increased gas use in others, oil and coal still appear as a mainstay of the regional energy mix.

- The persisting relevance of **solid fuels** (i.e. coal, lignite and derivative products) is explained on account of the large amounts of indigenous coal and lignite deposits - although not necessarily cheap, they provide easily accessible energy supplies for most countries of the region - and are seen as partly preventing a determined move towards decarbonisation. With the exception of Albania, the SEE countries have high shares of electricity generation from an ageing fleet of coal-fired power plants with low efficiencies.

- Western Balkan countries are not part of the EU's Emissions Trading Scheme, which is contributing to a growing gap with the rest of Europe. Electricity generation in the Western Balkan countries is "much cheaper" than in the EU and it will be hit by the EU's upcoming Carbon Border Adjustment Mechanism unless they win an exemption or adopt carbon pricing policies. Many Western Balkan countries are delaying **carbon pricing reforms** "as long as possible" because they fear the social upheaval caused by rising electricity prices and loss of employment in the coal regions.

- The SEE region is characterized by **high oil and gas import dependence**. Crude oil and oil product imports corresponded to 87% of total oil consumption and natural gas to 88.1%. This high reliance on hydrocarbon imports is driving many countries exploration efforts and this has already resulted in increased exploration work and new finds especially in Romania, Albania, Croatia, Cyprus, Israel, and Turkey. As latest analysis suggests, it looks possible that oil and gas production at SEE level will increase by 2025, thus lessening to a certain degree import dependence.

- However, the outlook for the SE European **upstream oil and gas industry** has rarely looked so uncertain. After two oil price crashes in five years, market and price risks are at their highest level in decades and upstream spending in 2020 was at its lowest in 15 years. The energy transition and the economic fallout from coronavirus will only make capital allocation decisions much more difficult.

- The so-called **peripheral countries** are playing an increasingly more influential role in the channeling of energy flows into the SEE region. Hence, there is a continuous need for the upgrading of both international electricity interconnections and cross-border gas interconnections.

- A rethink in the use of **natural gas is of vital importance** as its wide scale introduction and use could help decarbonize fast the existing coal power generation infrastructure of the region. Natural gas is becoming increasingly important to the energy mix of the various SEE countries. However, its further use is hampered because of poor infrastructure, lack of adequate cross-border interconnections, prevailing high prices (end of 2021) and the ambivalent EU energy policy concerning financing of new gas projects. The changing market structure, diversification of supplies and rising competition are positive signs, which will ensure price moderation and thus facilitate further penetration in the various countries' energy mix.

- SE Europe lags behind the rest of Europe in terms of **gasification**. Albania, Kosovo, Montenegro, Cyprus, North Macedonia and Bosnia and Herzegovina have no natural gas pipeline networks and no domestic natural gas resources. Despite its history of serving as one of the major gas transit corridors to

Western Europe (read Ukraine, Slovenia, Hungary), the SEE region has not been a destination of large quantities of Russian gas and it does not have a well-developed gas distribution network. The existing and emerging gas pipelines are not properly connected to the key nodal points, and especially one of the EU's central gas hubs, Baumgarten, in Austria.

- The start of operation in 2020 and 2021 respectively of the **TurkStream** and of the **TAP** trunk gas pipelines is changing the gas scene in SE Europe bringing higher gas liquidity and the prospect of operation of regional gas hubs.

- The **market liberalization** process in the electricity sector in most SEE countries, especially in Member Countries and in Turkey, has made impressive progress over the last five years, with unbundling having taken place and competition in the retail area now evident after many years of protectionism. Less impressive is progress in the natural gas sector, where competition is largely limited to the industrial sector with retail lagging seriously behind.

- **Nuclear power**, although it contributes only 4.1% to total gross inland consumption in SEE (including Turkey), remains a viable option since it covers important base load requirements in certain key countries (Romania, Bulgaria, Croatia, Slovenia, Hungary) and is fully compatible and supportive of EU's (revised) decarbonisation policies. In view of ongoing plans in Romania and Turkey for expansion of installed nuclear capacity, nuclear power is expected to play a more critical role in strengthening the power generation base of SEE over the next decade.

- **Energy efficiency** in SE Europe until very recently was is not given enough priority or attention although its role has been recognized in all EU Member States, which have enacted appropriate legislation, and by Energy Community Contracting Parties and Turkey and Israel. Although energy efficiency plays a critical role in limiting global energy demand, efforts to introduce energy efficiency in SE Europe, as an integral part of national energy planning, are in their infancy. The commitments under the Green Agenda for the Western Balkans to make energy efficiency the "first fuel" are yet to be transformed from a political declaration to concrete actions.

- **Energy poverty** affects households around the EU. Millions of families are unable to secure necessary levels of energy for their homes. The SEE countries have particularly high levels of energy poverty due to low incomes, high energy needs stemming from energy-inefficient housing, and limited access to diversified energy supply. In SEE, it is common for households to heat only certain rooms, and to do so for only limited periods. These conditions derive from the legacy of the socialist-type of development in their past. Despite strong evidence on the human costs of energy poverty on the ground, these challenges have not been adequately recognised or properly addressed in terms of policy.

- In terms of **security of energy supply**, the SEE region as a whole appears more vulnerable than the rest of Europe (mainly Western European countries). This is due to the as yet limited import options, mainly for gas, the difficult morphology of the various countries, and the region's reliance on a small number of oil and gas suppliers. Energy security in SEE can be strengthened by implementing a broad plan (already in progress) for improving interconnectivity for both electricity and gas across the region and also by diversifying further the energy mix of the various countries. Lately, and on account of latest experience, the list of energy security risks in SEE has been broadened to include physical hazards (i.e. earthquakes, floods, storms) as well as terrorist threats.

- The trends in the energy sector and the economy imply a **more interconnected SEE region**, including electricity networks and gas pipelines, which will help facilitate the integration of RES with high penetration and an optimum management of the energy balance, as well as the operation of the market, thus improving the security of energy supply. Moreover, the electricity networks of the region now form part of the interconnected European synchronized network where more and stronger interconnections are considered in the future, hence contributing to a single European electricity market. Therefore, the need for closer cooperation between the SEE countries in the energy sector is of paramount importance.

- The establishment in Thessaloniki of the **Regional Security Coordination Centre (SELeNe-se)** in 2021, is a most encouraging step in the right direction and is expected to greatly contribute towards strengthening electricity market operation and energy security.

- The SEE region, being close to major gas producer countries in its southeast borders and the East Med, can be used as a transit route for energy supply to the rest of Europe. Main energy routes include the Expanded South Corridor (gas) including TANAP-TAP and TurkStream, the Vertical Corridor (gas), the East-Med (gas), the EuroAsia Interconnector (electricity), etc. Besides the important geopolitical role of the region, these new interconnections will contribute to the security of energy supply overall in the European market. For such projects, cooperation schemes among the countries in the region are vital.

- The energy sector is characterised by new and **innovative technologies**, especially in energy efficiency and electricity, which should be introduced with measures to accelerate their deployment in the next period up to 2050. The transformation of electricity networks towards the network of the 21st century with new services and with interconnections based on new technologies are a major challenge for cooperation in the region and will also facilitate the European integration process. Indeed, technology is emerging as key transformational factor in the energy transition of the region and a review of technologies currently deployed shows that there is ample ground for innovation and the introduction of new technologies, not yet commercially available.

- Alongside power grid reinforcement, a diverse mix of flexible generation technologies in SEE (i.e. hydro technologies, flexible biomass, natural gas and storage) can facilitate the **integration of variable RES** – especially wind and solar PV. In particular, reduced flexibility needs and increased system reliability can be achieved by integrating countries and regions with fundamentally different weather regimes. An interconnected European power system would be highly beneficial for variable RES integration. Indeed, regional cooperation, stronger power systems and market integration will help minimize power system costs for consumers while maximizing supply security.

- Projects for the production and use of **green hydrogen** are still more political than economic. The projects aim to create a green hydrogen value chain connecting the RES capacities in SE Europe with the growing interest in hydrogen in Western Europe. Recently announced investments in (SE) Europe will undoubtedly give a strong impetus to the technologies for hydrogen production, storage and transport, as well as for its conversion back to useful energy.

- The aim of the EU member states of SE Europe is to meet their targets for **hydrogen deployment**, according to their NECPs, or otherwise stated targets. In the case of Western Balkans, the main goal is to develop viable hydrogen strategy. A good hydrogen strategies could reduce the share of coal/lignite in the regional energy mix and cut GHG emissions. In addition, several projects for the sustainable production of both green and blue hydrogen should be promoted and the majority, if not all, of the SEE countries should join in. It remains to be seen if the SEE region will appreciate the importance of hydrogen over the next years or it will lag behind developments in Western and Central Europe.

- In SE Europe, the **Electric Vehicle (EV)** deployment is still at a very early stage, even though it shows significant annual growth. The main barrier for further penetration of electric mobility in the region is the inadequate publicly accessible charging network, which, however, shows signs of improvement through large and small private initiatives as well as initiatives from local municipalities, businesses and institutions. The automotive component industry, being a very significant economic activity in SE Europe, must also adapt to the EV transition. The related regional markets associated with internal combustion engines, transmission systems, fuel systems, exhausts, forging components and small general parts are expected to be negatively affected by the transition to gearless, fuel-less, robust new vehicles. However, important segments of the regional manufacturing activity, such as batteries wiring, electric components, electronic architecture systems and telematics, are expected to attract new investors and expand their growth prospects.

- Looking at the **projection of gross inland energy consumption** in the EU member states of the SEE region, the overall tendency shows a stabilisation and even a small reduction in the time horizon to 2040. The decrease of the use of coal is evident, reaching a minimum level by 2040, while oil products lose part of their share in the gross inland consumption. The winners in this change are RES and nuclear energy. In contrast, the projection of gross inland energy consumption in the six Western Balkan countries presents a rather different story from that of the EU member states in the region. Following the expected growth of GDP, gross inland energy consumption is projected to increase by almost 40% between 2015 and 2040, with the amount of coal being held almost constant, close to 15 Mtoe. Natural gas is the emerging fuel with a constant gradual increase, connected with the pipeline and grid expansion projects in the East and Western Balkans region.

- In terms of **energy demand projection**, gross inland energy consumption in Turkey is slated to increase by more than 50% between 2020 and 2040. The role of renewable energy is seen to increase notably, reaching 28% of the GIC in 2040, the amount of coal remains at the level of 50 Mtoe with its relative contribution being reduced to 23% in 2040 and the contribution of natural gas is decreased to 17% of the GIC. Nuclear energy appears for the first time in the GIC of Turkey after 2025 with the operation of the Akkuyu nuclear power plant and is increasing until 2050, following the nuclear expansion program of the country.

- **Investment prospects** in the broader SEE region for energy related basic infrastructure and energy projects across the board (i.e. electricity, natural gas, RES, thermal power plants, oil and gas exploration, energy efficiency) look positive over the next decade. There appears to be significant improvement in anticipated and planned projects and related investment from now on until 2030. Compared to projections made in 2017 for the period 2016-2025, total estimated energy related investment in the region is much higher and amounts to €483.7 billion. Corresponding investments for the original 13-country group (as they appear in the 2017 Outlook) are slated at €387 billion, which is 41.8% higher compared to the 2017 estimates. This is a vast improvement compared to 5 years ago and clearly shows the substantially increased interest and appetite for energy investments in SE Europe.

Annexes

I. List of Acronyms and Unit Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AL	Albania
BBL	Barrel
BCC	Biomass Co-combustion
BCM	Billion Cubic Meters
B/D	Barrels per Day
BEH	Bulgarian Energy Holding
BEMIP	Baltic Energy Market Interconnection Plan
BG	Bulgaria
BiH	Bosnia and Herzegovina
BOE	Barrels of Oil Equivalent
Botas	Turkish Oil & Gas Pipelin Company
BP	British Petroleum PLC
BRUA	Interconnector Bulgaria-Romania-Hungary-Austria
BSEC	Black Sea Economic Cooperation Organization
BTC	Baku-Tbilisi-Ceyhan Oil Pipeline
BTE	Baku-Tbilisi-Erzurum Natural Gas Pipeline
BTU	British Thermal Unit
CAO	Coordinated Auction Office
CAPEX	Capital Expenditures
CBM	Coalbed Methane
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCT	Clean Coal Technologies
CCU	Carbon Capture and Utilisation
CDM	Clean Development Mechanism
CEER	Council of the European Energy Regulators
CER	Certified Emissions Reduction
CESEC	Central and South-Eastern European Gas Connectivity Group
CF	Cubic Foot
CGES	Centre for Global Energy Studies
CHP	Combined Heat & Power
CIF	Climate Investment Fund
CNG	Compressed Natural Gas
CNOOC	China's National Offshore Oil Company
CNPC	China National Petroleum Company
CO_2	Carbon Dioxide
COMECON	Council for Mutual Economic Assistance
CSE	Continental South East Region
CSO	Civil Society Organization
CSP	Concentrated Solar Power
DEPA	Public Gas Corporation (Greece)
DEFA	Public Gas Corporation (Cyprus)
DESFA	Natural Gas Transmission System Operator (Greece)
DH	District Heating
DSO	Distribution System Operator
E&P	Exploration & Production
EAEC	European Atomic Energy Community
EBRD	European Bank for Reconstruction and Development
EC	European Commission
ECB	European Central Bank
ECTO	Energy Community Treaty Organization
EdF	Électricité de France
EEA	Energy Efficiency Agency
EEC	European Economic Community
EED	Energy Efficiency Directive
EEPR	European Energy Programme for Recovery
EFSF	European Financial Stability Facility
EGAS	Egyptian Natural Gas Holding Company
EIA	Energy Information Administration, US Department of Energy
EIB	European Investment Bank
EJ	Exajoule
ELES	Slovenian Electricity TSO
EMRA	Turkish Energy Market Regulatory Agency
EnC	Energy Community
ENI	Italian National Hydrocarbon Company
ENTSO-E	European National Transmission System Operators for Electricity
NTSO-G	European National Transmission System Operators for Gas
EOR	Enhanced Oil Recovery
EPBD	Energy Performance of Buildings Directive
EPC	Engineering, Procurement and Construction
EPIA	European Photovoltaic Industry Association
ERA	Energy / Electricity Regulatory Authority
ERC	Energy / Electricity Regulatory Commission
ESIF	European Structural and Investment Funds
ESM	European Stability Mechanism
EU	European Union
EUA	European Union Allowances
EUETS	European Union Emissions Trading System
EURACOAL	European Association for Coal and Lignite
EV	Electric Vehicle
EWEA	European Wind Energy Association
FBiH	Federation of Bosnia and Herzegovina

FDI	Foreign Direct Investment
FEED	Front End Engineering and Design Study
FID	Final Investment Decision
FIT	Feed-In Tariff
FSRU	Floating Storage Regasification Unit
FSU	Former Soviet Union
GdF	Gaz de France
GDP	Gross Domestic Product
GENI	Global Energy Network Institute
GGF	Green for Growth Fund
GHG	Green House Gases
GHP	Geothermal Heat Pump
GIE	Gas Infrastructure Europe
GNP	Gross National Product
GRIP	Gas Regional Investment Plans
GW	Giga Watt
HELPE	Hellenic Petroleum
HERA	Croatian Energy Regulatory Agency
HHP	Hydro(electric) Power Plant(s)
HR	Croatia
HVDC	High Voltage Direct Current
IAEA	International Atomic Energy Agency
IAK	Interconnector Albania-Kosovo
IAP	Ionian Adriatic Pipeline
IBR	Interconnector Bulgaria-Romania
IBRD	International Bank for Reconstruction and Development
IBS	Interconnector Bulgaria-Serbia
ICH	Interconnector Croatia-Hungary
IEA	International Energy Agency
IENE	Institute of Energy for South East Europe
IFC	International Financial Corporation
IFI	International Financial Institutions
IGA	Intergovernmental Agreement
IGB	Interconnector Greece Bulgaria
IGI	Interconnector Greece Italy
IGU	International Gas Union
IISD	International Institute for Sustainable Development
IMF	International Monetary Fund
INA	Croatian National Oil & Gas Company
INDC	Intended Nationally Determined Contribution
IOCs	International Oil Companies
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
IRH	Interconnector Romania-Hungary
ISC	Interconnector Serbia-Croatia

ISK	Interconnector Serbia-Kosovo
ISO	Independent System Operator
ITB	Interconnector Turkey-Bulgaria
ITER	International Thermonuclear Experimental Reactor
ITGI	Interconnector Turkey-Greece-Italy
ITG	Interconnector Turkey Greece
JANAF	Croatian's Pipeline System Operator
KEK	Kosovo Energy Corporation
KESCO	Kosovo Electricity Supply Company
KESH	Albanian Power Corporation
KM	Kilometre
KOSTT	Kosovar Electricity Transmission, System and Market Operator
KTOE	Thousand Tons of Oil Equivalent
KV	Kosovo
KWe	kilowatt electrical capacity
LCOE	Levelised Cost of Energy
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
M&A	Mergers and Acquisitions
MBPD	Million Barrels Per Day
MENA	Middle East North Africa
MEPSO	North Macedonia's State-owned Electricity TSO
MJ	Montenegro
MOL	Hungarian Oil & Gas Company
MT/Y	Million Tons per Year
MTCE	Million Tonnes of Coal Equivalent
MTOE	Million Tons of Oil Equivalent
MW	Mega Watt
NATO	North Atlantic Treaty Organization
NBG	National Bank of Greece
NBP	UK National Balancing Point
NCG	NetConnect Germany Virtual Trading Point
NEK	Bulgarian National Electricity Co
NGL	Natural Gas Liquid
NGO	Non-governmental Organisation
NGTS	National Gas Transmission System
NIF	Neighborhood Investment Facility
NIGEC	National Iranian Gas Export Company
NIS	Serbian State Oil & Gas Company
NM	North Macedonia
NOC	National Oil Company
NOx	Nitrogen Oxides
NPP	Nuclear Power Plant
NPL	Non-Performing Loan
NRA	Nuclear Regulatory Agency
NREAP	National Renewable Energy Action Plans
NTC	Net Transfer Capacities

O&M	Operation and Maintenance
OECD	Organization for Economic Cooperation and Development
OHL	Overhead Line
OMV	Austrian Hydrocarbons Company
OPEC	Organization of Petroleum Exporting Countries
OSCE	Organization for Security and Cooperation in Europe
OSHEE	Albanian Distribution System Operator
OTC	Over-the-Counter
PCC	Pulverised Coal Combustion
PCI	Projects of Common Interest
PEOP	Pan European Oil Pipeline
PPC	Hellenic Public Power Co
PPP	Purchasing Power Parity
PSAs	Production Sharing Agreements
PSO	Public Service Obligations
PV	Photovoltaic
R&D	Research and Development
RCC	Regional Cooperation Council
REA	Regulatory Energy Authority of Greece
REEP	Regional Energy Efficiency Programme
RES	Renewable Energy Sources
RMD	Regional Market Design
RO	Romania
RS	Bosnia's Serb Republic
RWE	Reihn-Westfalia Electricity
SAA	Stabilization and Association Agreement
SC	Supercritical
SCP	South Caucasus Natural Gas Pipeline
SEE	South East Europe
SEECP	South East Europe Cooperation Process
SEEPEX	SE Europe Power Exchange
SEESEP	South East Europe Sustainable Energy Policy
SERC	State Electricity Regulatory Commission
SET-Plan	Strategic Energy Technology Plan
SEWRC	Bulgarian State Energy and Water Regulatory Commission
SGCC	State Grid Corporation of China
SN	Slovenia
SO_2	Sulphur Dioxide
SOCAR	State Oil Company of Azerbaijan Republic
TAEK	Turkish Atomic Energy Authority
TANAP	Trans Anatolian Pipeline
TAP	Trans Adriatic Pipeline
TBL	Trans-Balkan Oil Pipeline Consortium
TCM	Trillion Cubic Meters
TEN-E	Trans-European Networks
TETAS	Turkish Electricity Trading Company
TFC	Total Final Consumption (of Energy)
TGC	Tradable Green Certificates
TPA	Third Party Access
TPAO	Turkish Pipeline Oil Company
TPED	Total Primary Energy Demand
TPES	Total Primary Energy Supply
TPP	Thermal Power Plant
TSO	Transmission System Operator(s)
TTF	Dutch Title Transfer Facility Virtual Trading Point
TU	Turkey
TWh	Trillion Watts per hour
TYNDP	Ten-Year Network Development Plan
UCG	Underground Coal Gasification
UCTE	Union for the Coordination of Electricity Transmission
UGS	Underground Gas Storage
UK	United Kingdom
UN	United Nations
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
USA	United States of America
USGS	United States Geological Survey
USSR	Union of Soviet Socialist Republic
USTDA	United States Trade and Development Agency
VAT	Value Added Tax
WBIF	Western Balkans Investment Framework
WTO	World Trade Organization
ZEP	Zero Emissions Platform
ZTP	Belgian Zeebrugge Trading Point

II. Energy Balances of Countries

Albania, Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	1 946	42 081		2 412		18 662	670	6 699			72 469
Imports	3 045		48 488					5 357	11 435		68 326
Exports		-26 428	-7 182					-418	-2 774		-36 801
International marine bunkers				-1 327							-1 327
International aviation bunkers				-903							-903
Stock changes		-1 616	-2 675								-4 291
Total energy supply	**4 991**	**14 037**	**36 400**	**2 412**		**18 662**	**670**	**11 639**	**8 662**		**97 473**
Transfers											
Statistical differences			-141								-141
Electricity plants						-18 662	-80		18 742		
CHP plants											
Heat plants											
Gas works											
Oil refineries		-14 037	12 775								-1 262
Coal transformation											
Liquefication plants											
Other transformation								-79			-79
Energy industry own use			-1 095	-2 140					-1 349		-4 585
Losses			-84						-3 795		-3 879
Total final consumption	**4 991**		**47 855**	**271**			**590**	**11 560**	**22 259**		**87 527**
Industry	4 812		4 767	271			41	297	4 886		15 075
Transport			29 870					5 031	13		34 914
Residential			4 589				327	4 994	11 233		21 143
Commercial and public services	179		2 642				223	822	5 664		9 529
Agriculture / forestry			2 432					415	365		3 212
Fishing			1 633						97		1 730
Non-specified											
Non-energy use			**1 924**								**1 924**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Bosnia and Herzegovina Energy Balance 2019

Ktoe on a net calorific value basis	**Coal***	**Crude* oil***	**Oil products**	**Natural gas**	**Nuclear**	**Hydro**	**Geo-therma solar, etc.**	**Biofuels and waste**	**Elec-tricity**	**Heat**	**Total****
Production	142 461					21 964	1 022	60 845			226 292
Imports	47 059		66 130	7 871				94	10 170		131 323
Exports	-14 714		-1 717					-8 736	-23 634		-48 801
International marine bunkers											
International aviation bunkers			-388							-388	
Stock changes	-11 183	3 259	1 472								-6 452
Total energy supply	**163 624**	**3 259**	**65 497**	**7 871**		**21 964**	**1 022**	**52 202**	**-13 464**		**301 974**
Transfers											
Statistical differences	-4	280									276
Electricity plants	-123 866		-504	-242		-21 964	-1 022	-67	61 963		-85 702
CHP plants	-3 393							-179	756	1 688	-1 128
Heat plants	-2 349		-65	-1 741				-1 349		3 883	-1 621
Gas works											
Oil refineries		-3 540	3 151								-389
Coal transformation	-13 900										-13 900
Liquefication plants											
Other transformation								-1 407			-1 407
Energy industry own use	-6 447		-1 765						-5 155	-21	-13 388
Losses				-26					-4 525	-422	-4 973
Total final consumption	**13 664**		**66 314**	**5 861**				**49 200**	**39 575**	**5 128**	**179 742**
Industry	8 875		4 768	3 199				721	13 284	25	30 873
Transport			54 790	96					212		55 098
Residential	2 399		578	1 623				45 096	17 014	3 901	70 610
Commercial and public services	1 753		906	942				3 383	8 852	1 202	17 040
Agriculture / forestry	7		1 412						212		1 632
Fishing											
Non-specified											
Non-energy use	**630**		**3 859**								**4 489**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Bulgaria Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	198 438	180		1 356	180 767	10 546	12 496	82 139		2 217	488 139
Imports	16 789	298 917	91 153	102 907				4 811	10 962		525 539
Exports	-908		-182 654	-266				-7 931	-31 878		-223 637
International marine bunkers			-3 176								-3 176
International aviation bunkers			-10 180								-10 180
Stock changes	-868	-7 293	1 042	-1 763				-215			-9 096
Total energy supply	**213 452**	**291 805**	**-103 815**	**102 234**	**180 767**	**10 546**	**12 496**	**78 805**	**-20 917**	**2 217**	**767 590**
Transfers		10 774	-9 899								876
Statistical differences	-1 483	1 412	-615	-2 569				295	1 730	184	-1 047
Electricity plants	-169 280		-1 173	-843	-180 106	-10 546	-9 934	-4 518	139 275	-423	-237 549
CHP plants	-19 679		-1 832	-26 652	-660			-18 744	18 580	29 597	-19 389
Heat plants			-2	-6 812				-722		6 984	-552
Gas works											
Oil refineries		-312 856	298 772								-14 084
Coal transformation	-7 815										-7 815
Liquefication plants											
Other transformation		8 864		-8 941				-45			-122
Energy industry own use	-14		-18 209	-1 958					-20 280	-8 624	-49 085
Losses	-77		-66	-317					-9 959	-7 288	-17 707
Total final consumption	**15 105**		**163 162**	**54 141**			**2 562**	**55 071**	**108 428**	**22 646**	**421 115**
Industry	8 221		16 702	34 524				12 785	35 389	4 286	111 908
Transport			128 021	5 930				7 512	1 294		142 757
Residential	4 283		828	3 194			459	29 750	39 038	12 877	90 429
Commercial and public services	160		1 267	3 753			2 103	4 821	31 516	5 049	48 670
Agriculture / forestry	419		5 220	416				202	1 158	434	7 849
Fishing				1					33		33
Non-specified											
Non-energy use	**2 022**		**11 124**	**6 323**							**19 469**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Croatia Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
PProduction		31 070		35 641		20 974	8 171	66 838			162 695
Imports	18 799	97 066	106 000	69 398				4 827	41 043		337 133
Exports		-5 192	-92 282	-2 504				-10 503	-18 964		-129 446
International marine bunkers			-1 043								-1 043
International aviation bunkers			-8 357								-8 357
Stock changes	-1 160	1 837	-175	-1 801				-338			-1 637
Total energy supply	**17 640**	**124 781**	**4 144**	**100 733**		**20 974**	**8 171**	**60 824**	**22 079**		**359 346**
Transfers		-1 832	1 862								30
Statistical differences	11	4									15
Electricity plants	-14 078		-34	-17		-20 974	-7 223	-349	32 886		-9 789
CHP plants	-110		-285	-24 529				-12 057	12 668	11 526	-12 786
Heat plants			-175	-1 794				-3		1 655	-317
Gas works											
Oil refineries		-125 721	124 014								-1 707
Coal transformation											
Liquefication plants											
Other transformation		2 768		-2 768				-592			-592
Energy industry own use			-8 664	-7 364				-21	-3 501	-1 466	-21 016
Losses				-1 091					-5 972	-1 700	-8 764
Total final consumption	**3 463**		**120 862**	**63 170**			**948**	**47 803**	**58 159**	**10 015**	**304 420**
Industry	3 347		10 666	16 773				2 476	13 005	2 815	49 082
Transport			89 538	166				2 620	982		93 307
Residential	116		4 209	19 222			453	42 190	22 341	4 590	93 122
Commercial and public services			1 725	8 743			357	517	21 294	2 341	34 977
Agriculture / forestry			7 380	925			138		536	269	9 248
Fishing			995								995
Non-specified											
Non-energy use			**6 349**	**17 341**							**23 690**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.

** Totals may not add up due to rounding.

*** International marine and aviation bunkers are included in transport for world totals.

Cyprus Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production							4 772	1 889			6 661
Imports	844		109 044					3 026			112 914
Exports											
International marine bunkers			-11 648								-11 648
International aviation bunkers			-12 988								-12 988
Stock changes	-124		137					-149			-136
Total energy supply	**720**		**84 546**				**4 772**	**4 766**			**94 803**
Transfers			173								173
Statistical differences			144					-10	2		137
Electricity plants			-42 479				-1 645		18 301		-25 822
CHP plants								-345	209	51	-85
Heat plants											
Gas works											
Oil refineries											
Coal transformation											
Liquefication plants											
Other transformation								-53			-53
Energy industry own use			-1						-845		-846
Losses									-662		-662
Total final consumption	**720**		**42 384**				**3 127**	**4 358**	**17 005**	**51**	**67 645**
Industry	720		4 393				17	2 535	1 915		9 580
Transport			28 465					450			28 915
Residential			4 660				2 654	1 018	6 378		14 709
Commercial and public services			1 682				457	237	7 818		10 194
Agriculture / forestry			1 077					119	556	51	1 803
Fishing			82						12		94
Non-specified			359						325		684
Non-energy use			**1 666**								**1 666**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Creece Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	129 267	6 884		400		14 400	54 501	46 728			252 180
Imports	8 512	1 140 773	209 295	186 622				5 414	39 841		1 590 457
Exports		-10 968	-765 282	-571				-1 049	-4 043		-781 913
International marine bunkers			-105 435					-2			-105 436
International aviation bunkers			-47 337								-47 337
Stock changes	-3 965	13 446	5 266	1 505				-167			16 084
Total energy supply	**133 814**	**1 150 134**	**-703 492**	**187 956**		**14 400**	**54 501**	**50 925**	**35 798**		**924 036**
Transfers		95 328	-94 632								696
Statistical differences	2 569	-2 302	-352	-1 200				-97			-1 381
Electricity plants	-62 065		-42 821	-114 223		-14 400	-42 101	-692	143 811		-132 492
CHP plants	-66 017		-12 470	-12 016				-5 602	31 059	2 203	-62 842
Heat plants											
Gas works			-16								-16
Oil refineries		-1 243 160	1 274 015								30 855
Coal transformation			-1								-1
Liquefication plants											
Other transformation			-9					-93			-102
Energy industry own use			-54 677	-4 290				-17	-16 666		-75 650
Losses				-776					-13 293		-14 069
Total final consumption	**8 301**		**365 545**	**55 450**			**12 400**	**44 424**	**180 710**	**2 203**	**669 034**
Industry	8 132		36 009	14 002			71	5 820	44 308		108 343
Transport			243 922	749				7 733	730		253 134
Residential	143		48 295	16 093			11 465	28 457	62 559	2 203	169 215
Commercial and public services			5 266	6 404			759	1 119	64 493		78 040
Agriculture / forestry	26		1 567	100			105	1 259	8 560		11 617
Fishing			539					1	60		601
Non-specified	1		9 285	187				35			9 507
Non-energy use			**20 663**	**17 916**							**38 579**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Hungary Energy Balance 2019

Ktoe on a net calorific value basis	**Coal***	**Crude* oil***	**Oil products**	**Natural gas**	**Nuclear**	**Hydro**	**Geo-therma solar, etc.**	**Biofuels and waste**	**Elec-tricity**	**Heat**	**Total****
Production	41 596	48 709		55 607	178 272	788	18 653	117 253			460 879
Imports	44 734	263 842	173 611	652 307				13 917	71 471		1 219 881
Exports	-9 759	-8 318	-132 831	-244 033				-19 726	-26 168		-440 836
International marine bunkers											
International aviation bunkers			-11 610								-11 610
Stock changes	475	-1 092	-1 680	-109 497				-486			-112 280
Total energy supply	**77 045**	**303 141**	**27 490**	**354 384**	**178 272**	**788**	**18 653**	**110 957**	**45 302**		**1 116 034**
Transfers		-2 769	2 946								177
Statistical differences	-8		344	2 912				-28	702	5	3 928
Electricity plants	-41 168		-530	-33 531	-177 033	-788	-9 012	-20 096	106 103		-176 056
CHP plants	-4 699		-139	-32 869	-1 240		-36	-9 353	16 852	20 331	-11 153
Heat plants	-2 169		-80	-19 966			-6 213	-2 435	-83	28 122	-2 823
Gas works				202				-202			
Oil refineries		-312 758	312 948								190
Coal transformation	-12 235			-1 181							-13 416
Liquefication plants											
Other transformation		12 386	-11 524	-6 457							-5 594
Energy industry own use	-5 784		-16 154	-8 864				-591	-11 887	-4 768	-48 048
Losses	-781			-4 092					-11 851	-3 292	-20 016
Total final consumption	**10 201**		**315 301**	**250 538**			**3 392**	**78 253**	**145 138**	**40 398**	**843 220**
Industry	6 654		28 419	58 883			63	14 930	63 997	14 444	187 390
Transport			195 013	3 471				8 478	4 280		211 242
Residential	2 955		3 082	116 933			549	52 887	41 825	19 050	237 281
Commercial and public services	62		1 398	44 358			1 018	1 395	31 072	6 785	86 088
Agriculture / forestry	61		16 685	5 421			1 762	562	3 647	16	28 154
Fishing			85	3				1	50		139
Non-specified	13		384	707					266	103	1 473
Non-energy use	**456**		**70 234**	**20 763**							**91 453**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Israel Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	1 599	3 574		302 637			27 620	989			336 418
Imports	208 601	637 841	62 710	26 094				679			935 926
Exports			-261 504						-22 720		-284 224
International marine bunkers			-13 941								-13 941
International aviation bunkers			-50 031								-50 031
Stock changes	-11 251	-1 075	-3 903								-16 229
Total energy supply	**198 949**	**640 340**	**-266 668**	**328 731**			**27 620**	**1 668**	**-22 720**		**907 921**
Transfers											
Statistical differences	9 231	9 788	4 274						-869		22 423
Electricity plants	-206 345		-7 387	-233 948			-12 520	-400	242 666		-217 935
CHP plants	-614		-168	-25 180				-406	18 420		-7 948
Heat plants											
Gas works											
Oil refineries		-655 308	664 402								9 094
Coal transformation											
Liquefication plants											
Other transformation		5 181		-4 908							273
Energy industry own use	-481		-29 587						-11 717		-41 785
Losses									-9 512		-9 512
Total final consumption	**740**		**364 866**	**64 696**			**15 100**	**862**	**216 267**		**662 531**
Industry	740		16 475	60 102					45 195		122 512
Transport			253 879								253 879
Residential			6 542				15 100	183	72 398		94 223
Commercial and public services			4 372						66 750		71 122
Agriculture / forestry									13 533		13 533
Fishing											
Non-specified			10 702	4 594				679	18 391		34 366
Non-energy use			**72 897**								**72 897**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Kosovo Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	62 908					767	380	13 364			77 419
Imports	97		32 270					2 337	3 343		38 046
Exports	-212		-478					-2	-3 258		-3 951
International marine bunkers											
International aviation bunkers				-104							-104
Stock changes	204										204
Total energy supply	**62 996**		**31 687**			**767**	**380**	**15 700**	**85**		**111 614**
Transfers											
Statistical differences	45		-104					-7	-55	-15	-137
Electricity plants	-62 182		-155			-767	-364		22 862		-40 605
CHP plants											
Heat plants			-47							858	811
Gas works											
Oil refineries											
Coal transformation											
Liquefication plants											
Other transformation											
Energy industry own use									-1 799	-123	-1 922
Losses									-4 124	-101	-4 225
Total final consumption	**860**		**31 381**				**16**	**15 693**	**16 969**	**619**	**65 536**
Industry	435		7 758					612	3 754		12 559
Transport			17 904								17 904
Residential	105		495				4	14 464	9 101	401	24 571
Commercial and public services	319		2 221				11	479	3 613	218	6 861
Agriculture / forestry			878					137	501		1 516
Fishing											
Non-specified											
Non-energy use			**2 124**								**2 124**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Montenegro Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	16 574					5 881	1 064	7 270			30 789
Imports	55	230	17 766					66	4 304		22 420
Exports	-1 143		-1 326					-1 196	-3 394		-7 059
International marine bunkers											
International aviation bunkers				-1 032							-1 032
Stock changes	-61		533								472
Total energy supply	**15 425**	**230**	**15 941**			**5 881**	**1 064**	**6 140**	**909**		**45 590**
Transfers											
Statistical differences	1								-36		-35
Electricity plants	-15 110					-5 881	-1 056		12 353		-9 694
CHP plants											
Heat plants											
Gas works											
Oil refineries											
Coal transformation											
Liquefication plants											
Other transformation								-13			-13
Energy industry own use									-456		-456
Losses									-1 774		-1 774
Total final consumption	**316**	**230**	**15 941**				**8**	**6 127**	**10 995**		**33 617**
Industry	140	230	2 466					382	2 515		5 733
Transport			10 997						75		11 072
Residential	90		74					5 404	4 645		10 213
Commercial and public services	86		441				8	317	3 704		4 555
Agriculture / forestry			124					24	57		205
Fishing											
Non-specified											
Non-energy use			**1 839**								**1 839**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

North Macedonia Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	36 022					4 189	653	6 993			47 857
Imports	5 126		52 569	10 218				1 511	8 679		78 102
Exports	-20		-6 363					-12	-2 099		-8 494
International marine bunkers											
International aviation bunkers				-1 170							-1 170
Stock changes	1 851		-901	4				78			1 032
Total energy supply	**42 979**		**44 134**	**10 221**		**4 189**	**653**	**8 570**	**6 580**		**117 327**
Transfers											
Statistical differences	-97										-97
Electricity plants	-37 549		-683			-4 189	-450	-793	17 685		-25 979
CHP plants				-7 231					3 446	933	-2 852
Heat plants				-1 132						1 118	-14
Gas works											
Oil refineries											
Coal transformation											
Liquefication plants											
Other transformation											
Energy industry own use			-60						-1 721	-14	-1 796
Losses				-51			-18		-3 525	-237	-3 831
Total final consumption	**5 334**		**43 391**	**1 807**			**184**	**7 776**	**22 466**	**1 800**	**82 759**
Industry	5 262		5 894	1 483				315	5 832	17	18 803
Transport			31 649	74				4	51		31 777
Residential	26		435	8				7 220	10 943	1 319	19 951
Commercial and public services	22		2 433	242			42	180	5 497	464	8 880
Agriculture / forestry	23		528				143	58	143		895
Fishing											
Non-specified											
Non-energy use			**2 453**								**2 453**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Romania Energy Balance 2019

Ktoe on a net calorific value basis	**Coal***	**Crude* oil***	**Oil products**	**Natural gas**	**Nuclear**	**Hydro**	**Geo-therma solar, etc.**	**Biofuels and waste**	**Elec-tricity**	**Heat**	**Total****
Production	164 454	147 435		342 949	123 056	56 090	32 474	160 995			1 027 453
Imports	45 770	401 257	104 025	89 435				10 281	19 773		670 541
Exports	-13	-1 830	-232 522	-438				-1 583	-14 309		-250 695
International marine bunkers				-1 432							-1 432
International aviation bunkers				-6 390							-6 390
Stock changes	-4 747	-5 254	-1 257	-49 144				-107			-60 509
Total energy supply	**205 463**	**541 608**	**-137 576**	**382 802**	**123 056**	**56 090**	**32 474**	**169 586**	**5 465**		**1 378 969**
Transfers											
Statistical differences	3 029	8 137	-14 832	-6 637				4 447	-80	1 419	-4 517
Electricity plants	-132 647		-150	-31 457	-123 056	-56 090	-30 782	-909	184 543		-190 547
CHP plants	-38 202		-9 364	-59 920				-5 855	28 569	44 333	-40 440
Heat plants	-322		-3 969	-13 520			-618	-1 346		17 113	-2 662
Gas works											
Oil refineries		-554 455	574 420								19 965
Coal transformation	-9 537										-9 537
Liquefication plants											
Other transformation		5 846	-2 230	-4 231							-615
Energy industry own use	-771	-84	-29 555	-15 304				-175	-31 028	-7 288	-84 206
Losses	-1 664		-89	-2 479				-6	-23 405	-9 398	-37 040
Total final consumption	**25 349**	**1 052**	**376 655**	**249 254**			**1 075**	**165 742**	**164 064**	**46 179**	**1 029 370**
Industry	22 999	1 052	49 290	90 050			30	16 234	79 015	10 154	268 824
Transport			254 679	3				17 266	3 816		275 764
Residential	1 704		13 200	104 871			149	127 402	46 743	29 485	323 555
Commercial and public services	17		4 557	33 926			889	4 466	31 777	6 202	81 834
Agriculture / forestry	615		14 893	4 349			7	375	2 709	337	23 285
Fishing			1						3		4
Non-specified			8 668								8 668
Non-energy use	**15**		**31 367**	**16 054**							**47 435**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.

** Totals may not add up due to rounding.

*** International marine and aviation bunkers are included in transport for world totals.

Serbia Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	285 772	39 495		14 622		34 046	3 502	50 491			427 928
Imports	33 638	106 383	50 289	75 430				542	19 500		285 782
Exports	-758	-261	-33 109					-2 231	-19 227		-55 587
International marine bunkers				-685							-685
International aviation bunkers				-5 965							-5 965
Stock changes	-3 831	-2 375	2 554	-6 600				-933			-11 184
Total energy supply	**314 821**	**143 242**	**13 084**	**83 453**		**34 046**	**3 502**	**47 869**	**272**		**640 289**
Transfers		4 072	-3 759								313
Statistical differences	-430	467	234								271
Electricity plants	-214 717					-34 046	-3 282		113 309		-138 735
CHP plants	-55 334		-1 320	-9 148				-1 102	19 383	10 807	-36 714
Heat plants	-4 081		-3 577	-17 949				-91		22 698	-3 000
Gas works											
Oil refineries		-157 028	149 567								-7 461
Coal transformation	-15 906										-15 906
Liquefication plants											
Other transformation		9 267	-6 252	-4 676				-579			-2 240
Energy industry own use	-4 662	-20	-6 222	-7 016					-16 589	-1 914	-36 424
Losses	-2 140			-686				-2	-15 597	-2 886	-21 310
Total final consumption	**17 551**		**141 755**	**43 978**			**219**	**46 095**	**100 779**	**28 704**	**379 082**
Industry	7 060		15 504	20 742				8 151	31 619	8 344	91 420
Transport			94 440	451					1 349		96 240
Residential	8 768		1 983	8 507				36 475	48 025	15 762	119 519
Commercial and public services	1 530		2 443	7 803			88	1 137	18 556	4 598	36 154
Agriculture / forestry	2		3 858	816			132	333	1 230		6 370
Fishing											
Non-specified											
Non-energy use	**190**		**23 528**	**5 659**							**29 377**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Slovenia Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	36 871	22		171	63 505	16 126	2 177	26 410			145 282
Imports	9 151		207 174	30 624				3 774	32 477		283 200
Exports		-22	-98 316	-59					-33 623		-132 021
International marine bunkers				-7 802							-7 802
International aviation bunkers				-1 137							-1 137
Stock changes	-1 695		-1 556					255			-2 996
Total energy supply	**44 327**		**98 363**	**30 735**	**63 505**	**16 126**	**2 177**	**30 439**	**-1 147**		**284 525**
Transfers											
Statistical differences	-902										-902
Electricity plants	-32 874		-18	-252	-63 505	-16 126	-1 113	-15	52 808		-61 094
CHP plants	-8 456		-94	-4 178				-3 425	4 419	7 360	-4 374
Heat plants	-32		-126	-1 319			-39	-596		1 784	-328
Gas works											
Oil refineries											
Coal transformation											
Liquefication plants											
Other transformation											
Energy industry own use			-29	-38					-3 745	-828	-4 639
Losses									-3 090	-1 126	-4 216
Total final consumption	**2 064**		**98 096**	**24 949**			**1 025**	**26 403**	**49 245**	**7 190**	**208 973**
Industry	1 772		3 939	18 921				5 284	23 370	2 146	55 431
Transport	4		75 719	185				3 981	832		80 721
Residential	3		5 236	4 428			443	17 101	12 308	3 094	42 613
Commercial and public services			2 538	1 179			494	37	12 674	1 951	18 873
Agriculture / forestry			2 917				88		62		3 067
Fishing											
Non-specified			1 310								1 310
Non-energy use	**285**		**6 437**	**237**							**6 958**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

Turkey Energy Balance 2019

Ktoe on a net calorific value basis	Coal*	Crude* oil*	Oil products	Natural gas	Nuclear	Hydro	Geo-therma solar, etc.	Biofuels and waste	Elec-tricity	Heat	Total**
Production	729 703	131 981		16 316		319 762	571 770	143 800			1 913 332
Imports	1 017 855	1 381 467	863 561	1 558 490					7 961		4 829 335
Exports	-6 715	-13 833	-344 427	-26 294					-10 039		-401 309
International marine bunkers				-36 897							-36 897
International aviation bunkers				-184 427							-184 427
Stock changes	13 530	-7 766	5 233	2 475							13 473
Total energy supply	**1 754 373**	**1 491 849**	**303 043**	**1 550 987**		**319 762**	**571 770**	**143 800**	**-2 078**		**6 133 507**
Transfers		82 793	-81 191								1 602
Statistical differences	-39 967	-16 746	-4 590	10 004							-51 298
Electricity plants	-1 093 988		-58	-298 393		-319 762	-437 753	-27 159	1 046 720		-1 130 394
CHP plants	-14 905		-3 651	-84 833				-10 366	47 312	42 991	-23 453
Heat plants							-17 623			17 623	
Gas works											
Oil refineries		-1 644 267	1 564 918								-79 349
Coal transformation	-102 452										-102 452
Liquefication plants											
Other transformation		86 371	-50 424	-31 954						-17 623	-13 631
Energy industry own use	-50 268		-69 518	-63 457					-67 779		-251 022
Losses				-116					-112 628		-112 744
Total final consumption	**452 794**		**1 658 529**	**1 082 238**			**116 393**	**106 275**	**911 546**	**42 991**	**4 370 767**
Industry	274 351		141 227	386 268			12 100	36 341	401 795	42 991	1 295 073
Transport			1 147 463	14 154				7 006	5 679		1 174 302
Residential	54 337		8 759	496 230			78 042	62 928	202 299		902 595
Commercial and public services	124 106		33 642	158 769					267 317		583 833
Agriculture / forestry			123 753	5 425			26 251		33 833		189 262
Fishing			3 706	1 469					624		5 800
Non-specified											
Non-energy use			**199 979**	**19 924**							**219 903**

* The column of coal also includes peat and oil shale where relevant; that of crude oil includes crude oil, NGL, refinery feed stocks, additives and other hydrocarbons.
** Totals may not add up due to rounding.
*** International marine and aviation bunkers are included in transport for world totals.

III. Bibliography

Energy General

- BP Statistical Review of World Energy, London (2018, 2019, 2020, 2021)
- BP Energy Outlook, London (2018, 2019, 2020)
- Energy Community Secretariat (2018, 2019, 2020), Annual Implementation Report, Vienna
- International Energy Agency (IEA) (2018, 2019, 2020), World Energy Outlook, OECD/IEA, Paris
- Institute of Energy for South East Europe (IENE) (2011, 2017), South East Europe Energy Outlook, Study, Athens (www.iene.eu)
- International Energy Agency (IEA) (2008), Energy in the Western Balkans – The Path to Reform and Reconstruction, OECD/IEA, Paris
- International Energy Agency (IEA) (2018, 2019, 2020, 2021), World Energy Investment - Market Analysis and Forecasts, OECD/IEA, Paris
- SEE Legal (2018, 2019, 2020), The Southeast Europe Energy Handbook, Athens
- Stambolis, C. (2016, 2021), Greek Energy Directory, EditCom Ltd, Athens

Energy Policy and Climate Change

- European Commission (2021a), Fifth report on the state of the energy union, available at: https://ec.europa.eu/energy/topics/energy-strategy/energy-union/fifth-report-state-energy-union_en
- European Commission (2021b), European Climate Law, available at: https://ec.europa.eu/clima/policies/eu-climate-action/law_en
- European Commission (2021c), Forging a climate-resilient Europe - the new EU Strategy on Adaptation to Climate Change, COM (2021) 82 final, available at: https://ec.europa.eu/clima/sites/clima/files/adaptation/what/docs/eu_strategy_2021.pdf
- European Commission (2021d), "Recovery and Resilience Facility", available at: https://ec.europa.eu/info/business-economy-euro/recovery-coronavirus/recovery-and-resilience-facility_en
- European Commission (2020a), Powering a climate-neutral economy: An EU Strategy for Energy System Integration, COM (2020) 299 final, available at: https://ec.europa.eu/energy/sites/ener/files/energy_system_integration_strategy_.pdf
- European Commission (2020b), A hydrogen strategy for a climate-neutral Europe, COM (2020) 301 final, available at: https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf
- European Commission (2020c), A Renovation Wave for Europe - greening our buildings, creating jobs, improving lives, COM (2020) 662 final, available at: https://ec.europa.eu/energy/sites/ener/files/eu_renovation_wave_strategy.pdf
- European Commission (2020d), 2030 climate & energy framework, available at: https://ec.europa.eu/clima/policies/strategies/2030_en
- European Commission (2019), The European Green Deal, available at: https://eur-lex.europa.eu/resource.html?uri=cellar:b828d165-1c22-11ea-8c1f-01aa75ed71a1.0002.02/DOC_1&format=PDF
- European Commission (2015), Energy Union Package – A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, COM (2015) 80 final, available at: https://eur-lex.europa.eu/resource.html?uri=cellar:1bd46c90-bdd4-11e4-bbe1-01aa75ed71a1.0001.03/DOC_1&format=PDF
- International Energy Agency (IEA) (2021), Net Zero by 2050 – A Roadmap for the Global Energy Sector, OECD/IEA, Paris
- International Energy Agency (IEA) (2020), European Union 2020 – Energy Policy Review, OECD/IEA, Paris
- International Energy Agency (IEA) (2015), Energy and Climate Change, World Energy Outlook Special report, OECD/IEA, Paris
- Institute of Energy for South East Europe (IENE) (2020a), The Greek Energy Sector - Annual Report 2020, Study (M56), available at: https://www.iene.eu/articlefiles/greek%20energy%20sector%20study%202020_eng%201.pdf
- Institute of Energy for South East Europe (IENE) (2020b), Impact of the Coronavirus Pandemic on the Greek Energy Market, Study (M57), available at: https://www.iene.eu/articlefiles/special%20report.pdf
- Institute of Energy for South East Europe (IENE) (2019), The Greek Energy Sector - Annual Report 2019, Study (M03), Athens
- UNFCCC (1992), United Nations Framework Convention on Climate Change's Treaty, Doc No. 102-38.

Energy Efficiency

- International Energy Agency (IEA), Energy Efficiency (2018, 2019, 2020), OECD/IEA, Paris
- International Energy Agency (IEA) (2016a), Energy Efficiency, Market Report, OECD/IEA, Paris
- International Energy Agency (IEA) (2016b), Towards Sustainable Urban Energy Systems, Energy Technology Perspectives, OECD/IEA, Paris
- Energy Community (2015), Energy Community – Tapping On Its Energy Efficiency Potential, available at: https://www.energy-community.org/portal/page/portal/ENC_HOME/

Decarbonisation

- Agora Energiewende (2021), The Future of Lignite in the Western Balkans, https://www.agora-energiewende.de/en/projects/the-future-of-lignite-in-the-western-balkans/
- Simon, F. (2021a), "EU green finance advisors asked to clarify 'transition' to net-zero climate goal", Euractiv, available at: https://www.euractiv.com/section/energy-environment/news/eu-green-finance-advisors-asked-to-clarify-transition-to-net-zero-climate-goal/1560091/
- Simon, F. (2021b), "EU does not exclude funding gas, highways under green recovery plan", Euractiv, available at: https://www.euractiv.com/section/energy-environment/news/eu-does-not-exclude-funding-gas-highways-under-green-recovery-plan/
- Simon, F. (2020), "Eight EU states back 'natural gas' in net-zero transition", Euractiv, available at: https://www.euractiv.com/section/energy-environment/news/exclusive-eight-eu-states-back-natural-gas-in-net-zero-transition/
- World Bank (2020), A Road Map for a Managed Transition of Coal-Dependent Regions in Western Macedonia
- International Energy Agency (IEA) (2020a), Energy Technology Perspectives 2020, OECD/IEA, Paris
- International Energy Agency (IEA) (2020b), The role of CCUS in low-carbon power systems, OECD/IEA, Paris
- Ember and CAN Europe (2020), Just transition or just talk?, available at: https://caneurope.org/content/uploads/2020/09/2020-Just-transition-1.5.pdf
- London School of Economics (2020), "What is "decarbonisation" of the power sector? Why do we need to decarbonise the power sector in the UK?", available at: http://www.lse.ac.uk/GranthamInstitute/faqs/what-is-decarbonisation-of-the-power-sector-why-do-we-need-to-decarbonise-the-power-sector-in-the-uk/
- EndCoal (2020), "Global Coal Plant Tracker", available at: https://endcoal.org/global-coal-plant-tracker/
- Dempsey, H. (2019), "European coal plants forecast to lose €6.6bn in 2019", available at: https://www.ft.com/content/ba190c72-f590-11e9-b018-3ef8794b17c6
- WWF (2019), "41 European mayors declare support for a just transition from coal", available at: http://www.wwf.eu/?uNewsID=354315
- Lütkehermöller, K. et al. (2019), "Unlocking Low Cost Renewables in South East Europe", Agora Energiewende, available at: https://newclimate.org/wp-content/uploads/2019/10/Unlocking_SEE.pdf
- Dudau, R. and Cătuți, m. (2019), The Decarbonisation Challenge of Southeast Europe: A Case Study of Romania, available at: https://www.intereconomics.eu/contents/year/2019/number/6/article/the-decarbonisation-challenge-of-southeast-europe-a-case-study-of-romania.html
- Miljević, D. et al. (2019), Analysis of Direct and Selected Indirect Subsidies to Coal Electricity Production in the Energy Community Contracting Parties
- Buck, M., Risteska, S. and Redl, C. (2018), "A Clean-Energy Transition in Southeast Europe: Challenges, Options and Policy Priorities", Agora Energiewende, available at: https://www.agora-energiewende.de/fileadmin2/Projekte/2018/Energiewendedialog_Suedosteuropa/Agora-Energiewende_Impulse_SEE_energy_transition_priorities.pdf

Natural Gas

- International Energy Agency (IEA) (2021), Gas Market Report Q1-Q3 2021, OECD/IEA, Paris
- International Energy Agency (IEA) (2020a), Gas 2020, OECD/IEA, Paris
- International Energy Agency (IEA) (2020b), Global Gas Security Review 2020, OECD/IEA, Paris
- International Energy Agency (IEA) (2020c), The Role of Gas in Today's Energy Transitions, OECD/IEA, Paris
- Heather, P. (2021), European Traded Gas Hubs: German hubs about to merge, Oxford Institute of Energy Studies, available at:

https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/07/European-Traded-Gas-Hubs-NG-170.pdf
- Booth, A. (2021), LNG Winter 2020/2021 – A Unique Set of Circumstances or A Predictable Inevitability?, Oxford Institute of Energy Studies, available at: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/04/Insight-88-LNG-Winter-2020-2021.pdf
- SNAM, IGU, BloombergNEF (2020), Global Gas Report 2020
- IGU (2020), Wholesale Gas Price Survey – 2020 Edition, available at: https://www.igu.org/resources/wholesale-price-survey-2020-edition/
- GIIGNL (2020), Annual Report 2020, available at: https://giignl.org/publications/giignl-2020-annual-report
- DNV GL (2020), Annual Report 2020, available at: https://annualreport.dnv.com/2020
- Cohen, G. (2019), Long-Term Gas Contracting - Terms, definitions, pricing - Theory & practice, Study (M55), available at: https://www.iene.eu/articlefiles/Long-Term%20Gas.pdf
- Institute of Energy for South East Europe (IENE) (2019), Prospects for the Establishment of Gas Trading Hubs in SE Europe, Study (M49), Athens
- Institute of Energy for South East Europe (IENE) (2018), Gas Supply in SE Europe and the Key Role of LNG, Study (M46), available at: https://www.iene.eu//articlefiles/gas-supply-in-se-europe-and-the-key-role-of-lng.pdf
- Pirani, S. (2016), Azerbaijan's Gas Supply Squeeze and the Consequences for the Southern Corridor, Oxford Institute for Energy Studies, NG 110, Oxford
- Roberts, J. (2016), Completing Europe Gas Interconnections in Central and Southeastern Europe-an Update, Atlantic Council, Washington DC
- Stambolis, C., Sofianos, N. and Mastrapas, A. (2015), The Vertical Corridor – From the Aegean to the Baltic, Institute of Energy for South East Europe (IENE), Study (M26), available at: https://www.iene.eu/articlefiles/the%20vertical%20corridor%20-%20from%20the%20aegean%20to%20the%20baltic.pdf
- Stambolis, C. et al. (2014), The Outlook of a Natural Gas Trading Hub in SE Europe, Institute of Energy for South East Europe (IENE) Study (M19), Athens
- Institute of Energy for South East Europe (IENE) (2012), Global and Regional Natural Gas Developments, IENE Briefing Note No 1, Athens

Renewable Energy Sources

- IRENA (2021a), Renewable Power Generation Costs in 2020, International Renewable Energy Agency, Abu Dhabi, available at: https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020
- IRENA (2021b), The Republic of Albania, International Renewable Energy Agency, Abu Dhabi, available at: https://www.irena.org/publications/2021/March/Renewables-Readiness-Assessment-Albania
- IRENA (2021c), Renewable Capacity Statistics 2021, International Renewable Energy Agency, Abu Dhabi, available at: https://www.irena.org/publications/2021/March/Renewable-Capacity-Statistics-2021
- IRENA (2021d), Post-COVID recovery: An agenda for resilience, development and equality, International Renewable Energy Agency, Abu Dhabi, available at: https://www.irena.org/publications/2020/Jun/Post-COVID-Recovery
- International Energy Agency (IEA) (2020), Renewables 2020 – Analysis and Forecast to 2025, OECD/IEA, Paris
- International Energy Agency (IEA) (2020, 2021), Renewable Energy Market Update – Outlook for 2020/2021 and 2021/2022, OECD/IEA, Paris
- International Energy Agency (IEA) (2021), Hydropower Special Market Report – Analysis and forecast to 2030, OECD/IEA, Paris
- European Commission (2020), Renewable Energy Progress Report, COM (2020) 952 final, available at: https://ec.europa.eu/energy/sites/ener/files/renewable_energy_progress_report_com_2020_952.pdf

Electricity

- International Energy Agency (IEA) (2021a), Analytical Frameworks for Electricity Security, available at: https://iea.blob.core.windows.net/assets/c00b1c6c-ac9c-4d4b-b512-03dce54fc37b/Analytical_Frameworks_for_Electricity_Security.pdf
- International Energy Agency (IEA) (2021b), Power Systems in Transition, available at: https://www.iea.org/reports/power-systems-in-transition
- International Energy Agency (IEA) (2021c), Secure Energy Transitions in the Power Sector, available at: https://www.iea.org/reports/secure-energy-transitions-in-the-power-sector
- International Energy Agency (IEA) (2021d),

Electricity Market Report – July 2021, available at: https://iea.blob.core.windows.net/assets/01e1e998-8611-45d7-acab-5564bc22575a/ElectricityMarketReportJuly2021.pdf
- International Energy Agency (IEA) (2020a), Electricity Market Report, available at: https://www.iea.org/reports/electricity-market-report-december-2020
- International Energy Agency (IEA) (2020, 2021), Global EV Outlook 2020, 2021, OECD/IEA, Paris
- International Energy Agency (IEA) (2020b), Innovation in batteries and electricity storage, available at: https://www.iea.org/reports/innovation-in-batteries-and-electricity-storage
- Energy Community (2021), Electricity Interconnection Targets in the Energy Community Contracting Parties, Vienna, Austria
- Institute of Energy for South East Europe (IENE) (2020), The Integrated Electricity Markets in Greece and SE Europe, the Role of the International Electricity Interconnections and the Impact on Industry, Study (M54), Athens
- Institute of Energy for South East Europe (IENE) (2018), Prospects for the Electric Vehicle Market in Greece and Business Opportunities, Study (M47), available at: https://www.iene.gr/articlefiles/m47%20-%20meleti%20final.pdf

Oil

- International Energy Agency (IEA) (2021), Oil 2021 – Analysis and forecast to 2026, available at: https://iea.blob.core.windows.net/assets/1fa45234-bac5-4d89-a532-768960f99d07/Oil_2021-PDF.pdf
- International Energy Agency (IEA) (2020), Oil 2020 – Analysis and forecast to 2025, available at: https://www.iea.org/reports/oil-2020
- Oxford Institute of Energy Studies (2021), Oil Monthly Issues 1-6
- Mitrova, T. et al. (2021), Decarbonization of Oil & Gas: International Experience and Russian Priorities, Skolkovo, available at: https://energy.skolkovo.ru/downloads/documents/SEneC/Research/SKOLKOVO_EneC_Decarbonization_of_oil_and_gas_EN_22032021.pdf
- OPEC (2020), World Oil Outlook 2045, available at: https://www.opec.org/opec_web/static_files_project/media/downloads/press_room/Launch%20of%20the%20WOO2020%20-%20presentation.pdf

Economy

- World Bank (2021), Macro Poverty Outlook – Europe and Central Asia, available at: https://pubdocs.worldbank.org/en/107191492012467509/mpo-eca.pdf
- International Monetary Fund, World Economic Outlook Databases of October 2020 and April 2021, available at: https://www.imf.org/en/Publications/WEO/weo-database/2020/October and https://www.imf.org/en/Publications/WEO/weo-database/2021/April
- European Commission (2021a), National Recovery and Resilience Plans' assessments, available at: https://ec.europa.eu/info/business-economy-euro/recovery-coronavirus/recovery-and-resilience-facility/recovery-and-resilience-plans-assessments_en
- European Commission (2021b), Quarterly Report on the Euro Area, Volume 20, No 1 (2021), available at: https://ec.europa.eu/info/sites/default/files/economy-finance/ip146_en.pdf
- European Commission (2021c), European Economic Forecast – Winter 2021 (Interim), available at: https://ec.europa.eu/info/sites/default/files/economy-finance/ip144_en_1.pdf
- OECD (2020), COVID-19 Crisis Response In South East European Economies, available at: https://www.oecd.org/coronavirus/policy-responses/covid-19-crisis-response-in-south-east-european-economies-c1aacb5a/
- PwC (2020), Impact of COVID-19 and Economic Downturn on South East Europe Power and Utility Sector, available at: https://www.pwc.hr/en/assets/covid19/PwC-Perspective-COVID-19-and-Economic-Downturn-Impact-on-SEE-Power-and-Utility-Sector-202005.pdf

IV. Sponsors' and Supporters' Profiles

HELLENIC PETROLEUM

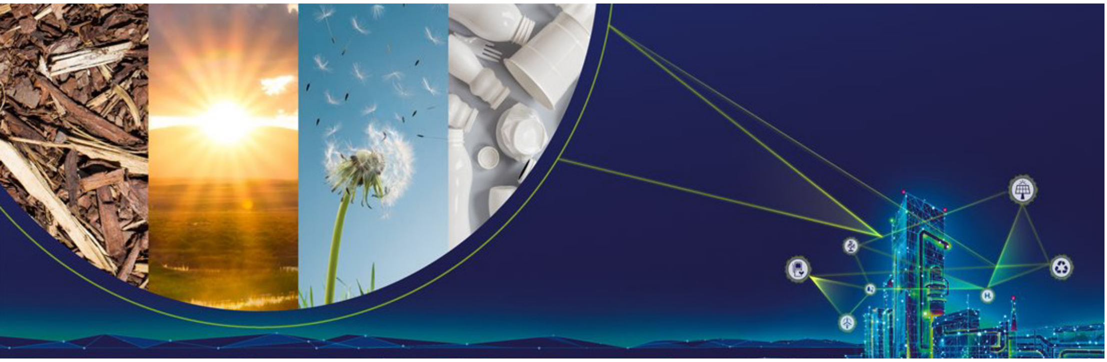
HELLENIC PETROLEUM GROUP

Founded in 1998, HELLENIC PETROLEUM is one of the leading energy groups in South East Europe, with activities spanning across the energy value chain and presence in six countries. The shares of the parent company HELLENIC PETROLEUM Holdings S.A. are primarily listed on the Athens Exchange (ATHEX: ELPE) with a secondary listing on the London Stock exchange (LSE: HLPD), while the Group's international bond issue is listed on the Luxemburg Stock Exchange.

In 2020, Group Adjusted EBITDA amounted to €333m, on total revenues of €5.8bn. HELLENIC PETROLEUM's key shareholders are Paneuropean Oil and Industrial Holdings S.A. (47%) and the Hellenic Republic Asset Development Fund (35.5%), with the remaining held by institutional (8.5%) and private (9%) investors.

Refining is the Group's core business, accounting for 75% of total assets. It owns three of the four refineries in Greece, of 344 kbpd total capacity, with a 60% share of the Greek wholesale oil products market.

The Group is the domestic ground fuels marketing leader, with a retail network of c.1,700 service stations throughout Greece as well as LPG, industrial, aviation and marine fuels and lubricants businesses. HELLENIC PETROLEUM is a leading player in SE European markets. Through its network of over 300 petrol stations is one of the key fuels marketing players in Cyprus, Serbia, Bulgaria, Montenegro and Republic of North Macedonia. HELLENIC PETROLEUM is the sole petrochemicals producer in Greece, mainly active in the propylene-polypropylene value chain. Domestic market share exceeds 50%, while exports, mainly in Turkey and other Mediterranean countries account for c. 70% of sales.



Moreover, HELLENIC PETROLEUM is active in the field of renewable energy sources with a portfolio of 80 MW in operation, which is expected to reach 300 MW upon the completion of the Kozani, N. Greece PV project and more than 1,7GW in various development stages.

The Group's exploration and production activities are focused on Greece through developing an exploration portfolio in onshore and offshore areas, either independently or in collaboration with leading companies in the sector such as Total, ExxonMobil, Repsol, Energean and Edison. HELLENIC PETROLEUM is also active in the power and gas sectors.

Power generation and trading activities are carried out through ELPEDISON, a JV with EDISON, which owns and operates two CCGT plants in Greece, totaling 840MW and is also present in the retail electricity market. The Group is present in the wholesale, supply and distribution of natural gas through its 35% stake in DEPA companies. The distribution company, DEPA Infrastructure is in sale process, following an international tender.

Hellenic Energy Exchange (HEnEx)

EnExGroup consists of Hellenic Energy Exchange S.A. (HEnEx S.A.) and EnEx Clearing House S.A. (EnExClear S.A.).

HEnEx S.A. was founded on 18.6.2018, following a spin-off of the Electricity Market branch of LAGIE S.A. and currently DAPEEP.S.A. Building upon accrued experience of more than a decade, operating continuously and consistently the Day-Ahead Scheduling Energy Transactions System, HEnEx S.A. has been designated by the Greek Regulator (Regulatory Authority for Energy-RAE) as Nominated Electricity Market Operator (NEMO) for the operation of the Day-Ahead and Intraday Electricity Markets.

Since 16.3.2020, following the approval of the Hellenic Capital Market Commission (HCMC), HEnEx S.A is also operating the Energy Financial Market, as Market Operator of the Energy Derivatives Market.

EnExClear S.A., a subsidiary of HEnEx founded on 02.11.2018, is responsible for the clearing and settlement of transactions concluded in the Day-Ahead and Intraday Markets, as well as the clearing and settlement of positions in the Balancing Market. EnExGroup has also undertaken the organization and operation of Greek Gas and Environmental Markets.

Independent Power Transmission Operator S.A. (IPTO)

The Independent Power Transmission Operator S.A. (IPTO) was established with Law 4001/2011 and was organized and operates as an Independent Transmission Operator in line with the provisions of EU Directive 2009/72/EC. The Company has the responsibilities and performs the duties of Owner and Operator of the Hellenic Electricity Transmission System (HETS), in accordance with the provisions of Law 4001/2011 the requirements in the Grid Code and the HETS operation license.

IPTO's compliance with the requirements applicable to the Independent Transmission Operator model was certified by the Regulatory Authority for Energy in December 2012.

The mission of IPTO is the operation, control, maintenance and development of the Hellenic Electricity Transmission System, to ensure the country's supply with electricity in an adequate, safe, efficient and reliable manner, as well as the operation of the electricity market for transactions outside the Day Ahead Scheduling, pursuant to the principles of transparency, equality and free competition.

Due to this critical role of the Company, all the necessary measures have been taken and all those necessary procedures have been set in place to ensure its independence, the strict adherence to the "equal treatment" principle for all System Users and Participants in the Electricity Market, transparency in its operation and respect of the confidentiality of the information which IPTO manages.

IPTO, as of 20 June 2019, has been following the Ownership Unbundling model and is fully harmonized with Directive 2009/72/EC. As Operator of the Hellenic Electricity Transmission System (HETS), IPTO's mission is to assure the country's supply with electricity in a safe, efficient and reliable manner, promoting free competition in the Greek electricity market, while ensuring the equal treatment of HETS users.

DEPA Commercial S.A.

Public Gas Corporation (DEPA Commercial)

DEPA Commercial is a modern and competitive company, with a dynamic presence in the energy sector and a substantial contribution to the growth of the Greek economy. The business plan implemented by the company, integrates the ESG criteria, aiming at "green" entrepreneurship, increasing its positive environmental and social footprint, while at the same time remaining committed to efficient and transparent corporate governance.

Through comprehensive planning, targeted investments, and the use of smart technologies, the company is striving to improve the quality of life for local communities, even in the most remote areas of the country, and at the same time contribute substantially to the reduction of energy poverty by offering budget-friendly and efficient energy. DEPA Commercial is focused on meeting the diverse needs of its customers by providing natural gas for households, industrial consumers, generators as well as fuel for gas-powered vehicles.In shipping, DEPA Commercial as the coordinator of the European co-financed projects Poseidon Med II and BLUE HUBS, introduces the maritime transport of the Eastern Mediterranean into the LNG era.
In this direction, the company is launching the construction of a new LNG bunkering vessel (BLUE HUBS program) and is proceeding to the acquisition of two tanker trucks for LNG refueling within the port of Piraeus. DEPA Commercial is a member of the research consortium for the implementation of the project SecureGas, funded by the European Union's Horizon 2020 research and innovation programme, aiming at increasing the security and resilience of gas network infrastructure, by taking into account physical and cyber threats.

The company also participates in the new Alexandroupolis LNG Terminal, a project of great importance at a national and European level, that enhances security of supply and access to LNG in SE Europe. Moreover, it takes part in the project of the Greek-Bulgarian gas pipeline IGB, which connects the Greek gas market with the markets of Central Europe and Ukraine.

DEPA Commercial is ready to enter the new era of "clean" energy, planning its dynamic entry into RES and other alternative means of energy production, such as hydrogen and biomethane, two fuels with a neutral environmental footprint.

Enerji Piyasaları İşletme A.Ş. (EPİAŞ)

Energy Exchange Istanbul (EXIST) or Enerji Piyasaları İşletme A.Ş. (EPİAŞ) by its Turkish name is an energy exchange company legally incorporated under the Turkish Electricity Market Law and enforced by the Energy Markets Operation License granted by the Energy Markets Regulatory Authority (EMRA) of Turkey. Main activities of EPİAŞ include efficient, transparent and reliable planning, creation, development, and operation of energy markets as defined under the market operating license.

EPİAŞ is responsible for managing and operating energy markets, including spot power and gas commodities. As by 2021 Future Delivery Electricity and Gas Markets will become available for the markets participants. Moreover EXIST/ EPİAŞ also responsible for the Renewable Energy Certificates (YEK-G) mechanism as well as the market soon to be open in 2021.

EPİAŞ has, since its e establishment, been carrying out its operations in line with the mission: to be an efficient, transparent, and reliable operator, and the vision: help Turkey become the regional energy trade hub. 2018 was a year of remarkable steps taken in the natural gas market in line with that vision.

In particular, 2017 staged numerous developments including, among others, grant of an authorization to EPİAŞ for operating the OWNGM, publication of the Organized Wholesale Natural Gas Market (OWNGM), and publication of Market Operating Rules and Procedures (MORP). In the framework of such developments, steps taken along with the goal to start the market continued more intensively in 2018.

New products and developments have been implemented in order to further the Spot Natural Gas Market we operate. In this context, as of June 1, 2020, "Weekly Products" were offered to our participants in the spot market, and a part from daily contracts, they were given the opportunity to trade on a 2-day weekend contract, a 5-day weekday contract, and a 7-day week-long contract. In addition, in line with the feedback received from our participants, as of December, we switched to an advance daily based model in the working structure of the transaction collateral limit and blocking system in our spot market.

ELPEDISON

ELPEDISON, the first Independent electricity producer in Greece and the biggest and most reliable electricity and Natural Gas supplier, is the outcome of the collaboration between two big Groups in the Energy sector.

ELPEDISON is the result of the joint venture between Hellenic Petroleum, one of the largest commercial and industrial energy Groups in Greece and South-East Europe and Edison, the longest-running electricity production utility in Europe and the largest private energy company in Italy.

Thanks to the knowledge and the experience that has inherited by its parent companies, ELPEDISON aspires to always be a leading company in its sector, playing a significant role in the power generation while offering its high quality energy products and services with stability and consistency. ELPEDISON, with its two privately-owned power plants in Thisvi (Voiotia)and Thessaloniki, of a total installed capacity of 820 MW, uses natural gas as fuel and ensures a clean and continuous electricity flow, based on a highly environmentally-friendly power generation process.

ELPEDISON covers the electricity needs of both residential and business customers, whether industrial or commercial, always offering competitive prices and high quality energy products and services.

Our Vision: Be the leader in providing outstanding & innovative energy solutions

Our Mission: We are committed to produce and sell power safely, contributing to the security of supply and sustainable development. We provide our customers with a top quality experience through our products and services. We operate with enthusiasm in what we do and we pride ourselves at offering our employees a place where they can excel, creating value.

Our Values:
• Safety• Safety is a top priority in all what we do
• Commitment-Engaged in heart and mind
• Customer focus-Care for our customers
• Integrity-Be ethical, fair, reliable and transparent
• Excellence-Challenge and improve the way we do things

IBEX

IBEX EAD (Independent Bulgarian Energy Exchange) was established January 2014, as a fully-owned subsidiary of Bulgarian Energy Holding EAD. IBEX holds a 10-year license (No-422-11) granted by the Energy and Water Regulatory Commission (EWRC) for organizing a Power Exchange for electricity in Bulgaria and in 2020 was nominated again by EWRC for a nominated electricity market operator (NEMO) in Bulgaria for a period of four years. IBEX works to establish and develop organised electricity market in Bulgaria based on transparent and non-discriminatory principles.

IBEX is a full member of the MRC (Multi-Regional Coupling), as well as an associated member of the PCR (Price Coupling of Regions)., IBEX EAD has been a full member of the association of European energy exchanges EUROPEX since January 2016 and is also a member of the All NEMO Committee.

The efforts of IBEX EAD are aimed entirely at providing a reliable, transparent and competitive electricity trading platforms to enable its more than 80 market participants (traders, consumers, generators and TSO/DSO companies) to enter into transactions through a variety of products. For this purpose, IBEX offers access to different trading platforms and organised market segments for short-term to long term products. The company currently operates three market segments-Day-ahead (launched on 19th January 2016), Intraday (launched on 12th April 2018) and Bilateral Contracts (launched on 24th October 2016, with its Auctions and Continuous trading screens). In terms of financial products, EEX AG in cooperation with IBEX offers Bulgarian power futures on its market as of June 2019. In October 2020 the company added yet another service to its portfolio- access to the IDM market segment via API (application programming interfaces).

In addition to developing the local wholesale market in its role of a power exchange operator, IBEX is part of several market coupling initiatives. In November 2019 through the border with Romania it joined the Single Intraday Coupling (SIDC) as part of the project's second wave. The BG-GR border is expected to be integrated in 2022. In the Day-ahead timeframe, Bulgaria was successfully coupled with Greece on 11.5.2021. The testing for the BG-RO MC project starts on 20th September 2021 with go-live planned for the last week of October 2021.

ENERGEAN OIL & GAS

Established in 2007, Energean is a London Premium Listed FTSE 250 and Tel Aviv 35 Listed E&P company with operations in nine countries across the Mediterranean and UK North Sea. Since IPO, Energean has grown to become the leading independent, gas-focused E&P company in the Eastern Mediterranean, with a strong production and development growth profile.

The Company explores and invests in new ideas, concepts and solutions to produce and develop energy efficiently, at low cost and with a low carbon footprint. The company has an 80% gas weighted portfolio with almost 1 billion barrels of oil equivalent 2P reserves, while its production comes mainly from the Abu Qir field in Egypt and fields in Southern Europe.

The company's flagship project is the 3.5 Tcf Karish, Karish North and Tanin development, offshore Israel, where it intends to use the newbuild fully-owned FPSO Energean Power, which will be the only FPSO in the Eastern Mediterranean, to produce first gas, commencing mid-2022.

Energean has signed contracts for 7.2 Bcm/yr of gas sales on plateau into the Israeli domestic market, which have floor pricing, take-or-pay and/or exclusivity provisions that largely insulate the project's revenues against global commodity price fluctuations and underpin Energean's goal of paying a meaningful and sustainable dividend.

With a strong track record of growing reserves and resources, Energean is focused on maximising production from its large-scale gas-focused portfolio to deliver material free cash flow and maximise total shareholder return in a sustainable way. ESG and health and safety are paramount to Energean; it aims to run safe and reliable operations, whilst targeting carbon-neutrality across its operations by 2050.

These aspirations were significantly advanced with the completion of the Edison E&P acquisition in December 2020, which is now being successfully integrated in Energean's business.

MOTOR OIL

MOTOR OIL is an energy group based in Greece. It was founded in 1970 and its refinery, one of the top refineries in Europe (11,5 Nelson Complexity Index) started operating in the region of Corinth in 1972. It plays a leading role in the sectors of crude oil refining and marketing of petroleum products in Greece, as well as the greater eastern Mediterranean region, supplying its customers with a wide range of high-quality products. It exports in more than 45 countries and has about 2500 employees.

Since 2001 the Company shares have been listed on the Athens Exchange. It is also a constituent of the ATHEX Composite Share Price Index, the FTSE/ATHEX LARGE CAP index, the MSCI Greece Small Cap Index and the FTSE4Good Index Series.

Motor Oil also has a significant presence in the area of trade due to the liquid fuel retail networks of its subsidiaries AVIN OIL and Coral (formerly SHELL HELLAS S.A.). Coral, a Shell licencee, also operates in Cyprus, Serbia, Croatia & North Macedonia.

In the lubricants sector, the Group is represented by its subsidiary, LPC S.A. LPC is active in the industrial production of basic lubricants, the production, and trade of packaged lubricants and the sale of paraffin.The company exports its products to more than 45 countries and is the agent for internationally known VALVOLINE lubricants in Greece.

The Group enjoys a presence in the liquified gas sector through Coral Gas S.A. The company stores, packages and markets bottled and bulk liquified gas and liquified gas for vehicles (autogas). In 2017, the company established a subsidiary in Cyprus intending to expand its activities abroad.

Additionally, the Group has a presence in the power and natural gas market through its subsidiary NRG TRADING HOUSE ENERGY S.A. NRG offers electricity and natural gas programs, and primarily aims to provide comprehensive services to home and commercial consumers through top-level services that meet all energy needs. Motor Oil is also active in the Renewable Energy Sector.

Hellenic Gas Transmission System Operator (DESFA)

Desfa is responsible for the operation, management, utilization and development of the Greek Natural Gas System and its interconnections, in a technically sound and economically efficient way, in order to best serve its Users with safety, reliability and adequacy.

Possessing extensive experience and a highly skilled workforce, Desfa, whose shareholders are, from 2018, 34% the Greek State and 66% Senfluga SA (joint company of Snam, Enagás, Fluxys and Damco), contributes decisively to the security of supply and the diversification of supply sources of Greece and the wider region, while facilitating the development of competition in the Greek energy market.

On the way to a cleaner and more sustainable energy future, Desfa is transformed, with the vision of its further consolidation as a reliable partner in the framework of the ongoing international energy projects in Southeast Europe and beyond.

t the same time, Desfa implements a series of significant investments for the upgrade, expansion and interconnection of the National Natural Gas System, with a key role for the smooth energy transition of Greece and the goal of its emergence as an international energy hub.

On a consistent basis, Desfa also implements activities aimed at strengthening its positive social and environmental footprint, consistent in its vision to be a model of business excellence and corporate responsibility in every aspect of its operation.

ΔΕΔΑ

ΔΗΜΟΣΙΑ ΕΠΙΧΕΙΡΗΣΗ ΔΙΚΤΥΩΝ ΔΙΑΝΟΜΗΣ ΑΕΡΙΟΥ

DEDA

The Public Enterprise of Gas Distribution Networks (namely DEDA) demonstrates a well-established presence with innovative projects and actions, hence it is broadly considered as a pioneer in both national and European level, contributing to our country's transitional process towards the digitized and "clean" energy new era.

Our ambitious yet realistic 2021-2025 Development Plan serves as a compass for the company, as DEDA develops energy infrastructure of key importance across several Greek regions, thus providing natural gas access to thousands of households, small and medium enterprises, industries and public buildings, such as schools and hospitals.

DEDA's Development Program is the largest gas distribution network expansion project currently implemented in Europe. It provides for the construction of 1,860 new kilometers of network and at least 70,000 consumer connections of all categories (residential, commercial, industrial) - ultimately reaching 170,000 by 2036 - in 34 cities in the Regions of Eastern Macedonia and Thrace, Central Macedonia, Western Macedonia Epirus, Central Greece and Western Greece.

With a total budget of €300 million, it capitalizes on DEDA's own funds, national and EU resources. The benefits of DEDA projects may be regarded as a multiplying factor for employment, the environment, the economy and, of course, the entire society. Further, energy costs are significantly reduced for households, businesses and industry, while, at the same time the environmental footprint is reduced, as growth and employment are significantly boosted. It should also be indicatively noted that the projects, while fully developed, will mobilize direct and indirect investments totaling €1 billion and will create about 6,000 new jobs.

DEDA moves forward every day, shielding every corner of the country from an energy point of view, with safe and, at the same time, innovative and environmentally respecting infrastructure, that serves the needs of local communities, thus becoming a substantial factor for the sustainable development of the country.

HHRM
HELLENIC HYDROCARBON
RESOURCES MANAGEMENT

HHRM SA

Founded in 2011 with the Greek state as its sole shareholder, Hellenic Hydrocarbon Resources Management (HHRM SA) manages national interests regarding the exploration, research, and production of hydrocarbons. The company also works methodically to accelerate the development and monetization of Greece's upstream hydrocarbon industry, with a particular focus on natural gas, in view of the significant and positive impacts the industry could have on Greece's economic and social development.

Driven by the belief that the world needs to urgently transition to a sustainable carbon-neutral economy, and bearing in mind the pivotal role of natural gas as a bridging fuel, HHRM's management established a new vision for the company focused on being an enabler of Greece's energy transition goals. To this end, the company has recently undertaken numerous initiatives to strengthen environmental and social governance in the sector through new governance frameworks, while steps are being taken aimed at accelerating the exploitation of the country's natural gas deposits.

Likewise, and as part of the company's role in supporting the attainment of the goals set out in Greece's National Energy and Climate Plan (NECP), HHRM has established a New Ventures department focused on exploring synergies between the oil and gas industry and new energy technologies such as Carbon Capture and Storage, offshore wind farms, and hydrogen.

As the single administrator of Greece's hydrocarbons data archive, HHRM prioritizes taking measures to strengthen its data library with new geophysical and geochemical data, and continuously update its assessment of the hydrocarbon potential of Greece's geological basins. Because of this, HHRM has unparalleled technical know-how and expertise regarding Greece's hydrocarbon potential. The company has created strategic synergies with academic institutes, major market players, and government authorities and is working with investors and legislators to leverage its offshore expertise to contribute to the deployment of new energy technologies. HHRM maintains an open-door policy and attractive conditions for potential investors, and looks forward to welcoming new partners to further develop Greece's energy resources.

Hellenic Copper and Aluminium industry S.A.

ElvalHalcor Hellenic Copper and Aluminium industry S.A. (ElvalHalcor), is a global industrial leader with advanced technology, 84 years' experience and expertise, focused in sustainable operation and growth, offering aluminium and copper processing industrial products and solutions for dynamically growing markets.

ElvalHalcor was formed in December 2017 via the merger of Elval, a leading European aluminium rolling company, and Halcor, the largest copper tubes producer in Europe. ElvalHalcor is listed on the Athens Stock Exchange (ELHA).

ElvalHalcor is a leader in the global aluminium and copper markets. Halcor, the copper & alloys extrusion division of ElvalHalcor, is the leading European copper tubes producer. Elval (the aluminium rolling division of ElvalHalcor), is one of the leading global manufacturers of aluminium rolled products being at the top of the market.

The Company has a strong production base across 17 industrial units with cutting edge technology and a market presence in 102 countries.

With 84 years of experience and know-how, ElvalHalcor has a highly extrovert business model with solid presence in more than 100 countries globally by developing sustainable and high value-added products and solutions that meet the requirements of the most demanding customers. ElvalHalcor contributes to climate neutrality and circular economy by offering high value-added sustainable aluminium and copper products and technologically advanced tailor-made solutions in growing dynamic markets. ElvalHalcor is a leader in the copper and aluminium industries and having grown based on sustainability principles.

ElvalHalcor seizes the opportunities created in rapidly developing markets fueled by global megatrends: the transition to climate neutrality, circular economy and the growth of renewable energy and e-mobility by offering sustainable and high value-added products and solutions that meet the requirements of the most demanding customers.

GREENTOP
ENERGY SYSTEMS S.A.

GREENTOP

Greentop Energy Systems S.A., is a privately-owned Greek Company, established in 2009. It belongs to entrepreneurs with stake interest on shipping, real estate and construction. Chartered to exploit and develop renewable energy sources from greenfield, the Company mainly focuses on wind and solar projects.

The Company employs highly qualified well recognized professionals with extensive experience and successful carriers in the stream of the Renewable Energy Market and the Construction sector.

Realizing the prospects of renewables in Greece, Greentop exploited various areas with wind and solar potential. Following the required licensing regulations, the Company created a project portfolio of more than 360MW in wind and solar capacity.

In house know-how complimented by certified specialized and experienced outsourcing, analyses and carries detailed assessments and studies ensuring the technical suitability and economic viability of each site and potential project.

EnSCo Energy Services Company AG

EnSCo is amongst a handful of companies able to trade energy in almost all the CWE and C/SEE countries. In its six years of operation (2015-2021) EnSCo has established itself as a reliable partner in the European energy sector with presence in the major European markets.

EnSCo's Main Activities include: Electricity Trade The main activity of the parent company (ENSCO AG based in Switzerland) in cross-border electricity trading across Europe.

- Energy Services (provided by the Greek subsidiary EnSCo SA)
- Energy Audits to industrial, commercial and residential sectors
- Energy Conservation (EC) & rational use of energy
- Demand Side Management (DSM) projects
- Small combined heat & power (CHP) project development
- Renewable energy project development
- Electricity Supply Balancing Services
- Small RES and CHP producer representation to the wholesale energy markets

n addition to electricity trading EnSCo SA offers a range of integrated energy services including:

- Energy Audits and Consulting
- Diagnosis of present energy use and energy conservation potential
- Hierarchical positioning energy efficiency measures, including: energy conservation (EC), rational use of energy (RUE), demand side management (DSM), building management systems (BMS), combined heat & power (CHP) and renewable energy sources (RES)
- Identification of alternative options for electricity and natural gas suppliers
- Technical and Economic Assessment of high priority projects
- Project Implementation
- Project development, licensing, project design, equipment selection, project management
- Project Implementation Monitoring and Commissioning of Operations
- Technical Personnel Training
- Operations Monitoring during contracted term

KYRIAKIDES GEORGOPOULOS
Law Firm

KG Law Firm

KYRIAKIDES GEORGOPOULOS (KG) Law Firm is a leading Greek multi-tier business law firm and the largest in Greece, dating back to 1930's and recognized as one of the most prestigious law firms in Greece. The firm numbers over 100 highly skilled lawyers who are actively involved in the provision of legal services to high profile Greek and international clients in complex and innovative cross-border deals. With offices in Athens and Thessaloniki, our multi-disciplinary teams set the standards for commercially-aware, responsive service in the most complicated and sophisticated legal issues. KG pioneered in the Greek market by becoming ISO certified since 2006 and still remains one of a handful of ISO 9001 certified law firms in Greece. Our firm is well known for having one of the very few practice groups in the country dedicated exclusively to energy infrastructure related projects. We have played a significant role in the liberalization of the electricity and gas market and we continue to be active in most of the privatization initiatives in these sectors whilst our track record of more than 40 years supports our leading role in the market (Greece and the region of south east Europe).

Besides our oil and gas expertise, our continuous exposure allowed us to develop an innovative specialization in renewable energy sources (e.g. wind, solar, hydro, biomass, waste to energy, biogas and geothermal). Our team addresses with success the rapid transformation of the energy sector and continues to lead most of the important and innovative 'country first' transactions and has developed extensive knowledge on the development of energy storage, LNG-to-power, licensing of FSRU's. Our advice is attuned to our clients' commercial imperatives, as well as the political, technical and stakeholder relationship aspects of our clients' businesses and operations. We use a multidisciplinary, team-based approach to legal advice and problem solving, combining experience and expertise in regulatory law, mergers and acquisitions, project finance, business and corporate law.

KG Law Firm's Energy Infrastructure performance is consistently ranked highly by the most prestigious of international directories, such as Chambers & Partners Global, Chambers & Partners Europe, Legal 500 EMEA, as well as IFLR1000.

INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

Institute of Energy for SE Europe (IENE)
3 Alex. Soutsou Street, 10671, Athens Greece
ISBN: 978-960-999940-5-7

Layout: BarkDesign • Printed in Greece by G. Kostopoulos Graphic Arts

South East Europe
Energy Outlook **2021/2022**

LEAD SPONSOR

HELLENIC PETROLEUM

SPONSORS

EnEx Energy Exchange Group

ipto INDEPENDENT POWER TRANSMISSION OPERATOR

ΔΕΠΑ DEPA Commercial S.A.

EPİAŞ

elpedison Δίπλα σας με όλη μας την ενέργεια

SUPPORTERS

IBEX

ENERGEAN

MOTOR OIL

DESFA

ΔΕΔΑ ΔΗΜΟΣΙΑ ΕΠΙΧΕΙΡΗΣΗ ΔΙΚΤΥΩΝ ΔΙΑΝΟΜΗΣ ΑΕΡΙΟΥ

HHRM HELLENIC HYDROCARBON RESOURCES MANAGEMENT

ELVALHALCOR HELLENIC COPPER AND ALUMINIUM INDUSTRY S.A.

GREENTOP ENERGY SYSTEMS S.A.

EnSCo sustainable efficiency

KG KYRIAKIDES GEORGOPOULOS Law Firm

IENE
INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE

www.iene.eu

ISBN 978-960-99940-5-7