SEERMAP

South East Europe Electricity Roadmap

SOUTH EAST EUROPE ELECTRICITY ROADMAP

# Country report

# Romania

**SEERMAP: South East Europe Electricity Roadmap**
**Country report: Romania 2017**

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The South East Europe Electricity Roadmap (SEERMAP) project develops electricity sector scenarios until 2050. The project focuses on 9 countries in South East Europe: Albania, Bosnia and Herzegovina, Bulgaria, Greece, Kosovo*, former Yugoslav Republic of Macedonia, Montenegro, Romania and Serbia. The implications of different investment strategies in the electricity sector are assessed for affordability, energy security, sustainability and security of supply. In addition to analytical work, the project focuses on trainings, capacity building and enhancing dialogue and cooperation within the SEE region.

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

Further information about the project is available at: **www.seermap.rekk.hu**

Funding for the project was provided by the Austrian Federal Ministry of Agriculture, Forestry, Environment and Water Management and the European Climate Foundation.

**The project was carried out by a consortium of 5 partners, and involved 9 local partners as subcontractors. The consortium was led by the Regional Centre for Energy Policy Research (REKK).**

The **Regional Centre for Energy Policy Research (REKK)** is a Budapest based think tank, and consortium leader of the SEERMAP project. The aim of REKK is to provide professional analysis and advice on networked energy markets that are both commercially and environmentally sustainable. REKK has performed comprehensive research, consulting and teaching activities in the fields of electricity, gas and carbon-dioxide markets since 2004, with analyses ranging from the impact assessments of regulatory measures to the preparation of individual companies' investment decisions.

The **Energy Economics Group (EEG),** part of the Institute of Energy Systems and Electrical Drives at the Technische Universität Wien (TU Wien), conducts research in the core areas of renewable energy, energy modelling, sustainable energy systems, and energy markets. EEG has managed and carried out many international as well as national research projects funded by the European Commission, national governments, public and private clients in several fields of research, especially focusing on renewable and new energy systems. EEG is based in Vienna and was originally founded as research institute at TU Wien.

The **Electricity Coordination Centre (EKC)** provides a full range of strategic business and technical consultancy and engineering leading models and methodologies in the area of electric power systems, transmission and distribution systems, power generation and electricity markets. EKC was founded in 1993 and provides consultant services from 1997 in the region of South-East Europe, Europe as well as in the regions of Middle East, Eastern Africa and Central Asia. EKC also organises educational and professional trainings.

The work of **OG Research** focuses on macroeconomic research and state of the art macroeconomic modelling, identification of key risks and prediction of macroeconomic variables in emerging and frontier markets, assessment of economic developments, and advice on modern macroeconomic modelling and monetary policy. The company was founded in 2006 and is based in Prague and Budapest.

The **Energy Regulators Regional Association (ERRA)** is a voluntary organisation comprised of independent energy regulatory bodies primarily from Europe, Asia, Africa, the Middle East and the United States of America. There are now 30 full and 6 associate members working together in ERRA. The Association's main objective is to increase exchange of information and experience among its members and to expand access to energy regulatory experience around the world.

**Local partners in SEERMAP target countries**

The **Energy Policy Group (EPG, Romania)** is a Bucharest-based independent, non-profit think-tank grounded in 2014, specializing in energy policy, markets, and strategy. EPG seeks to facilitate an informed dialogue between decision-makers, energy companies, and the broader public on the economic, social, and environmental impact of energy policies and regulations, as well as energy significant projects. To this purpose, EPG partners with reputed think-tanks, academic institutions, energy companies, and media platforms.

**POLIS University (U_Polis, Albania)** is young, yet ambitious institution, quality research-led university, supporting a focused range of core disciplines in the field of architecture, engineering, urban planning, design, environmental management and VET in Energy Efficiency.

**ENOVA (Bosnia and Herzegovina)** is a multi-disciplinary consultancy with more than 15 years of experience in energy, environment and economic development sectors. The organization develops and implements projects and solutions of national and regional importance applying sound knowledge, stakeholder engagement and policy dialogue with the mission to contributing to sustainable development in South East Europe.

The **Center for the Study of Democracy (CSD, Bulgaria)** is a European-based interdisciplinary non-partisan public policy research institute. CSD provides independent research and policy advocacy expertise in analysing regional and European energy policies, energy sector governance and the social and economic implications of major national and international energy projects.

**FACETS (Greece)** specialises in issues of energy, environment and climate, and their complex interdependence and interaction. Founded in 2006, it has carried out a wide range of projects including: environmental impact assessment, emissions trading, sustainability planning at regional/municipal level, assessment of weather and climate-change induced impacts and associated risks, forecasting energy production and demand, and RES and energy conservation development.

**Institute for Development Policy (INDEP, Kosovo*)** is a Prishtina based think tank established in 2011 with the mission of strengthening democratic governance and playing the role of public policy watchdog. INDEP is focused on researching about and providing policy recommendations on sustainable energy options, climate change and environment protection.

**MACEF (Macedonia)** is a multi-disciplinary NGO consultancy, providing intellectual, technical and project management support services in the energy and environmental fields nationally and worldwide. MACEF holds stake in the design of the energy policy and energy sector and energy resources development planning process, in the promotion of scientific achievements on efficient use of resources and develops strategies and implements action plans for EE in the local self-government unit and wider.

**Institute for Entrepreneurship and Economic Development (IPER, Montenegro)** is an economic thing tank with the mission to promote and implement the ideas of free market, entrepreneurship, private property in an open, responsible and democratic society in accordance with the rule of law in Montenegro. Core policy areas of IPER's research work include: Regional Policy and Regional Development, Social Policy, Economic Reforms, Business Environment and Job Creation and Energy Sector.

**RES Foundation (Serbia)** engages, facilitates and empowers efficient networks of relationships among key stakeholders in order to provide public goods and services for resilience. RES stands for public goods, sustainability and participatory policy making with focus on climate change and energy.

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# 1 | Executive summary

South East Europe is a diverse region with respect to energy policy and legislation, comprising a mix of EU member states, candidate and potential candidate countries. Despite this diversity, shared challenges and opportunities exist. The electricity network of the South East Europe region is highly interconnected, energy policies more harmonised and electricity markets better integrated – as a result of the EU accession process, the Energy Community Treaty and, more recently, the Energy Union initiative supporting a regional perspective on policy development.

The SEERMAP project uses a model-based assessment of different long term electricity investment strategies for Albania, Bosnia and Herzegovina, Bulgaria, Greece, Kosovo*, former Yugoslav Republic of Macedonia, Montenegro, Romania and Serbia. It builds upon previous work in the region, namely IRENA (2017), the DiaCore, BETTER and SLED projects, but also EU-level analysis, notably the EU Reference Scenario 2013 and 2016. The current assessment shows that alternative solutions exist for replacing current generation capacity by 2050, with different implications for affordability, sustainability and security of supply.

In Romania, more than 80% of current fossil fuel generation capacity, approximately 6000 MW, is expected to be decommissioned by the end of 2030, and none of the current generation capacity will operate by 2050. This provides both a challenge to ensure a policy framework which will incentivise needed new investment, and an opportunity to shape the electricity sector over the long term in-line with a broader energy transition unconstrained by the current generation portfolio.

Five models incorporating the electricity and gas markets, the transmission network and macro-economic system were used to assess the impact of 3 core scenarios:

- The 'no target' scenario reflects the implementation of current energy policy (including implementation of renewable energy targets for 2020 and completion of all power plants listed in official planning documents) combined with a $CO_2$ price (applied from 2030 onwards for non-EU states), but no 2050 $CO_2$ target in the EU or Western Balkans;
- The 'decarbonisation' scenario reflects a long-term strategy to significantly reduce $CO_2$ emissions according to indicative EU emission reduction goals for the electricity sector as a whole by 2050, driven by the $CO_2$ price and strong, continuous RES support;
- The 'delayed' scenario envisages an initial implementation of current national investment plans followed by a change in policy from 2035 onwards that leads to the same emission reduction target by 2050 as the 'decarbonisation' scenario. The attainment of the target is driven by the $CO_2$ price and increased RES support from 2035 onwards.

**The modelling work carried out under the SEERMAP project identifies some key findings** with respect to the different electricity pathways that Romania can take:

- Under scenarios with an ambitious decarbonisation target and corresponding RES support schemes, Romania will have an electricity mix with 75% renewable generation, mostly wind and hydro, with a significant contribution from biomass, by 2050. If renewable support is phased out and no $CO_2$ emission target is set, the share of RES in electricity consumption will reach around 54% in 2050. This represents a very moderate increase compared to current levels over this long time horizon.

- Delayed action on renewables is feasible but the increased effort required towards the end of the modelled period to meet the $CO_2$ emission reduction target requires a significant increase in RES support.
- Coal and lignite fired generation is phased out in all scenairos by 2030, in accordance with national plans. National plans do not contain any new coal or lignite plants, and the model does not build any new capacities, confirming that coal is not a cost-efficient generation option in Romania. The total share of fossil fuel based generation decreases in all scenarios compared with current levels by 2050, as natural gas based generation also peaks in 2040-2045. The decrease in the share of natural gas over the long term is driven by the rising price of carbon and gas which results in unprofitable utilisation rates.
- Natural gas plays a transitory role in electricity generation in all three scenarios. Natural gas investments are mostly limited to the 'no target' scenario, partially replacing retiring capacities over time but gas capacity in 2050 is only half of that in 2016. The corresponding growth in natural gas based generation is due to higher utilisation rates (above 50% from 2040, even reaching more than 60% in the 'no target' scenario by 2050). However, gas based generation falls between 2041 and 2050 to 13% of total electricity generation. Contrary to the 'no target' scenario, in the 'delayed' and 'decarbonisation' scenarios gas based generation disappears by 2050 after peaking in 2040.
- Romania approaches self-sufficiency over time due to the doubling of nuclear power generation, the temporary increase of gas based generation and the uptake of renewables in the 'delayed' and 'decarbonisation' scenarios. Its generation and system adequacy indicators remain favourable as well.
- In both scenarios with an emission reduction target, the Romanian electricity sector is fully decarbonised by 2050 with substantial constribution of nuclear generation. In the two scenarios with a decarbonisation target, the utilisation rate of nuclear is around 6% lower then in the 'no target' scenario, due to a higher share of more competitive renewable generation.
- Long term planned RES support does not drive up wholesale electricity prices compared to a scenario with no emission reduction target. The price of electricity follows a similar trajectory under all scenarios and only diverges after 2045. After this year, prices are lower in scenarios with high levels of RES in the electricity mix due to the low marginal cost of RES based electricity production.
- Under all scenarios there is a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels. This characterises the entire SEE region, and the EU as a whole, in all scenarios for the modelled time period. The price increase is driven by the price of carbon and the price of natural gas, both of which increase significantly by 2050.
- Affordability of electricity for households deteriorates in some periods. In the 'delayed' scenario, a substantial (approximately 130%) increase in household electricity expenditure to income occurs by the end of the modelled period compared to current levels. Affordability is most favourable by the end of the period in the 'decarbonisation' scenario, with only a 50% increase in household expenditure on electricity compared to current levels.
- Decarbonisation will require significantly more investment in generation capacity, assumed to be financed by private actors who accept higher CAPEX in exchange for

low OPEX (plus RES support) in their investment decisions. From a social point of view, the high level of investment has a modest positive impact on GDP. There is virtually no impact on the external balance, public debt or employment.

- RES support will gradually fall during the modelled period under scenarios with an emission reduction target, with the exception of the last decade in the 'delayed' scenario, when significant investment in renewables requires high levels of RES support.
- With a modest investment in the transmission network Romania can harness the benefits of increasing renewable penetration in the form of higher NTCs available for electricity trade and decreasing network losses.

**A number of no regret policy recommendations can be provided based on results which are robust across all scenarios:**

- The increasing renewable penetration suggests a policy focus on enabling RES integration; this involves investing in transmission and distribution networks, enabling demand side management and RES production through a combination of technical solutions and appropriate regulatory practices, and promoting investment in storage solutions including hydro and small scale storage.
- Co-benefits of investing in renewable electricity generation, such as a GDP increase, can strengthen the case for increased RES investment. Additional co-benefits, not assessed here, are health and environmental benefits from reduced emissions of air pollutants.
- In order to enable Romania to implement an ambitious renewable policy, a stable renewable energy support framework is needed. A significant share of the RES support for decarbonisation of the electricity sector can be covered by EU ETS revenues, thereby relieving the corresponding surcharge to consumers. Still, delayed action towards renewables will adversely affect the financial burden of households at the end of the modelled period.
- A stable renewable energy support scheme could also contribute to reducing the risks for investors in RES technologies, enabling reductions in the cost of capital. As RES investments are sensitive to financial costs, this would reduce the overall burden on final consumers to finance the RES deployment present in all scenarios.
- Regional level planning, including establishment of regional markets, increasing cross-border capacities and incentivising storage capacities with regional significance, can improve system adequacy compared with plans which emphasise reliance on national production capacities.

# 2 | Introduction

Over the past decades EU energy policy has focused on a number of shifting priorities. Beginning in the 1990s, the EU started a process of market liberalisation in order to ensure that the energy market is competitive, providing cleaner and cheaper energy to consumers. Three so-called energy packages were adopted between 1996 and 2009 addressing market access, transparency, regulation, consumer protection, interconnection, and adequate levels of supply. The integration of the EU electricity market was linked to the goal of increasing competitiveness by opening up national electricity markets to competition from other EU countries. Market integration also contributes to energy security, which had always been a priority but gained renewed importance again during the first decade of the 2000s due to gas supply interruptions from the dominant supplier, Russia. Energy security policy addresses short and long term security of supply challenges and promotes the strengthening of solidarity between member states, completing the internal market, diversification of energy sources, and energy efficiency.

Climate mitigation policy is inextricably linked to EU energy policy. Climate and energy were first addressed jointly via the so-called '2020 Climate and energy package' initially proposed by the European Commission in 2008. This was followed by the '2030 Climate and energy framework', and more recently by the new package of proposed rules for a consumer centred clean energy transition, referred to as the 'winter package' or 'Clean energy for all Europeans'. The EU has repeatedly stated that it is in line with the EU objective, in the context of necessary reductions according to the IPCC by developed countries as a group, to reduce its emissions by 80-95% by 2050 compared to 1990, in order to contribute to keeping global average temperature rise below 2°C compared with pre-industrial levels. The EU formally committed to this target in the 'INDC of the European Union and its 28 member states'. The 2050 Low Carbon and Energy Roadmaps reflect this economy-wide target. The impact assessment of the Low Carbon Roadmap shows that the cost-effective sectoral distribution of the economy-wide emission reduction target translates into a 93-99% emission reduction target for the electricity sector (EC 2011a). The European Commission is in the process of updating the 2050 roadmap to match the objectives of the Paris Agreement, possibly reflecting a higher level of ambition than the roadmap published in 2011.

The South East Europe Electricity Roadmap (SEERMAP) project develops electricity sector scenarios until 2050 for the South East Europe region. Geographically the SEERMAP project focuses on 9 countries in South East Europe: Albania, Bosnia and Herzegovina, Kosovo* (in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence), former Yugoslav Republic of Macedonia, Montenegro and Serbia (WB6) and Bulgaria, Greece and Romania (EU3). The SEERMAP region consists of EU member states, as well as candidate and potential candidate countries. For non-member states some elements of EU energy policy are translated into obligations via the Energy Community Treaty, while member states must transpose and implement the full spectrum of commitments under the EU climate and energy acquis.

Despite the different legislative contexts, the countries in the region have a number of shared challenges. These include an aged electricity generation fleet in need of investment to ensure replacement capacity, consumers sensitive to high end user prices, and challenging fiscal conditions. At the same time, the region shares opportunity in the form of large potential for renewables, large potential of hydro generation which can be a valuable asset for system balancing, a high level of interconnectivity, and high fossil fuel reserves, in particular lignite, which is an important asset in securing electricity supply.

Taking into account the above policy and socio-economic context, and assuming that the candidate and potential candidate countries will eventually become member states, the SEERMAP project provides an assessment of what the joint processes of market liberalisation, market integration and decarbonisation mean for the electricity sector of the South East Europe region. The project looks at the implications of different investment strategies in the electricity sector for affordability, sustainability and security of supply.

The aim of the analysis is to show the challenges and opportunities ahead and the trade-offs between different policy goals. The project can also contribute to a better understanding of the benefits that regional cooperation can provide for all involved countries. Although ultimately energy policy decisions will need to be taken by national policy makers, these decisions must recognise the interdependence of investment and regulatory decisions of neighbouring countries. Rather than outline specific policy advise in such a complex and important topic, our aim is to support an informed dialogue at the national and regional level so that policymakers can work together to find optimal solutions.

# 3 | Methodology

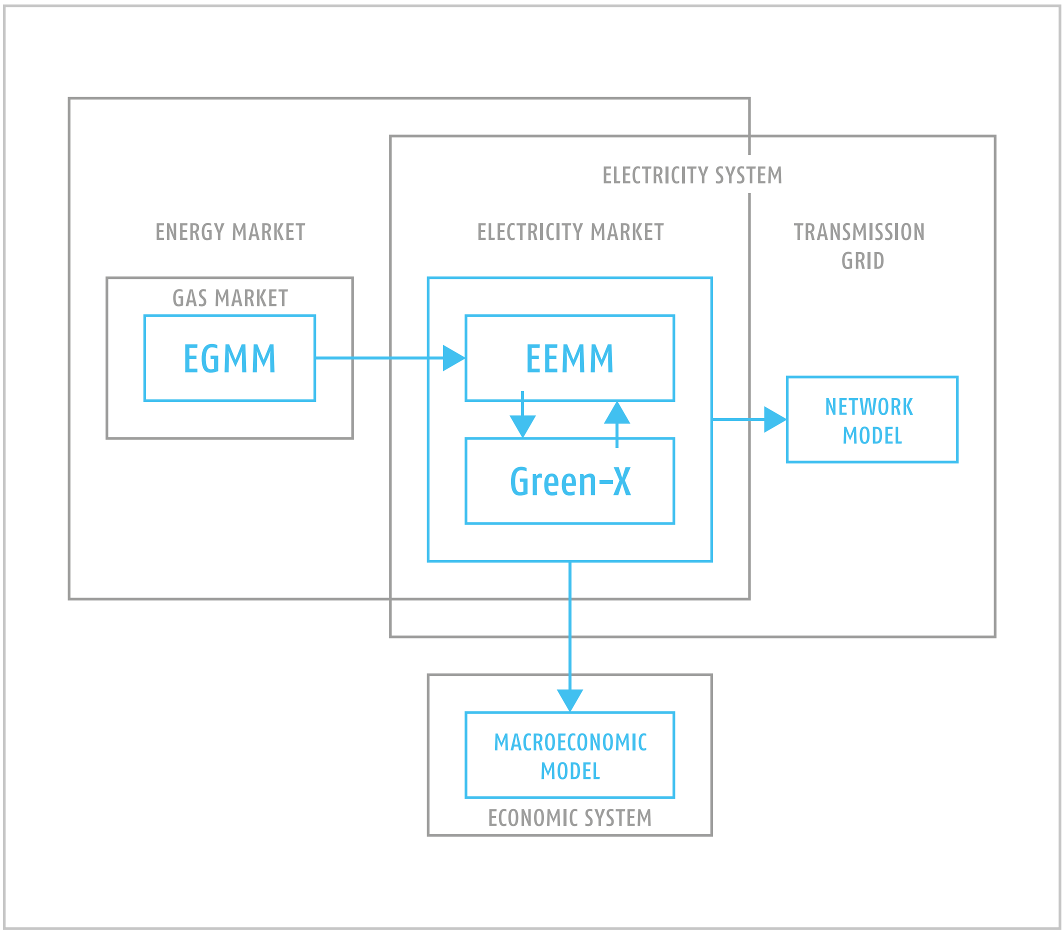
Electricity sector futures are explored using a set of five high resolution models incorporating the crucial factors which influence electricity policy and investment decisions. The European Electricity Market Model (EEMM) and the Green-X model together assess the impact of different scenario assumptions on power generation investment and dispatch decisions. The EEMM is a partial equilibrium microeconomic model. It assumes that the electricity market is fully liberalised and perfectly competitive. In the model, electricity generation as well as cross border capacities are allocated on a market basis without gaming or withholding capacity: the cheapest available generation will be used, and if imports are cheaper than producing electricity domestically demand will be satisfied with imports. Both production and trade are constrained by the available installed capacity and net transfer capacity (NTC) of cross border transmission networks respectively. Due to these capacity constraints, prices across borders are not always equalised. Investment in new generation capacity is either exogenous in the model (based on official policy documents), or endogenous. Endogenous investment is market-driven, whereby power plant operators anticipate costs over the upcoming 10 years and make investment decisions based exclusively on profitability. If framework conditions (e.g. fuel prices, carbon price, available generation capacities) change beyond this timeframe then the utilisation of these capacities may change and profitability is not guaranteed.

The EEMM models 3400 power plant units in a total of 40 countries, including the EU, Western Balkans, and countries bordering the EU. Power flow is ensured by 104 interconnectors between the countries, where each country is treated as a single node. The fact that the model includes countries beyond the SEERMAP region incorporates the impact of EU market developments on the SEERMAP region.

The EEMM model has an hourly time step, modelling 90 representative hours with respect to load, covering all four seasons and all daily variations in electricity demand. The selection of these hours ensures that both peak and base hours are represented, and that the impact of volatility in the generation of intermittent RES technologies on wholesale price levels are captured by the model. The model is conservative with respect to technological developments and thus no significant technological breakthrough is assumed (e.g. battery storage, fusion, etc.).

The Green-X model complements the EEMM with a more detailed view of renewable electricity potential, policies and capacities. The model includes a detailed and harmonised

**FIGURE 1**
THE FIVE MODELS USED FOR THE ANALYSIS
*A detailed description of the models is provided in a separate document ("Models used in SEERMAP")*




methodology for calculating long-term renewable energy potential for each technology using GIS-based information, technology characteristics, as well as land use and power grid constraints. It considers the limits to scaling up renewables through a technology diffusion curve which accounts for non-market barriers to renewables but also assumes that the cost of these technologies decrease over time, in line with global deployment (learning curves). The model also considers the different cost of capital in each country and for each technology by using country and technology specific weighted average cost of capital (WACC) values.

An iteration of EEMM and Green-X model results ensures that wholesale electricity prices, profile based RES market values and capacities converge between the two models.

In addition to the two market models, three other models are used:

- the European Gas Market Model (EGMM) to provide gas prices for each country up to 2050 used as inputs for EEMM;
- the network model is used to assess whether and how the transmission grid needs to be developed due to generation capacity investments, including higher RES penetration;
- macroeconomic models for each country are used to assess the impact of the different scenarios on macroeconomic indicators such as GDP, employment, and the fiscal and external balances.

# 4 | Scenario descriptions and main assumptions

## 4.1 Scenarios

From a policy perspective, the main challenge in the SEE region in the coming years is to ensure sufficient replacement of aging power plants within increasingly liberalised markets, while at the same time ensuring affordability, security of supply and a significant reduction of greenhouse gas emissions. There are several potential long-term capacity development strategies which can ensure a functioning electricity system. The roadmaps assess 3 core scenarios:

- The 'no target' scenario reflects the implementation of current energy policy and no $CO_2$ target in the EU and Western Balkans for 2050;
- The 'decarbonisation' scenario reflects a continuous effort to reach significant reductions of $CO_2$ emissions, in line with long term indicative EU emission reduction goal of 93-99% emission reduction for the electricity sector as a whole by 2050;
- The 'delayed' scenario involves an initial implementation of current investment plans followed by a change in policy direction from 2035 onwards, resulting in the realisation of the same emission reduction target in 2050 as the 'decarbonisation' scenario.

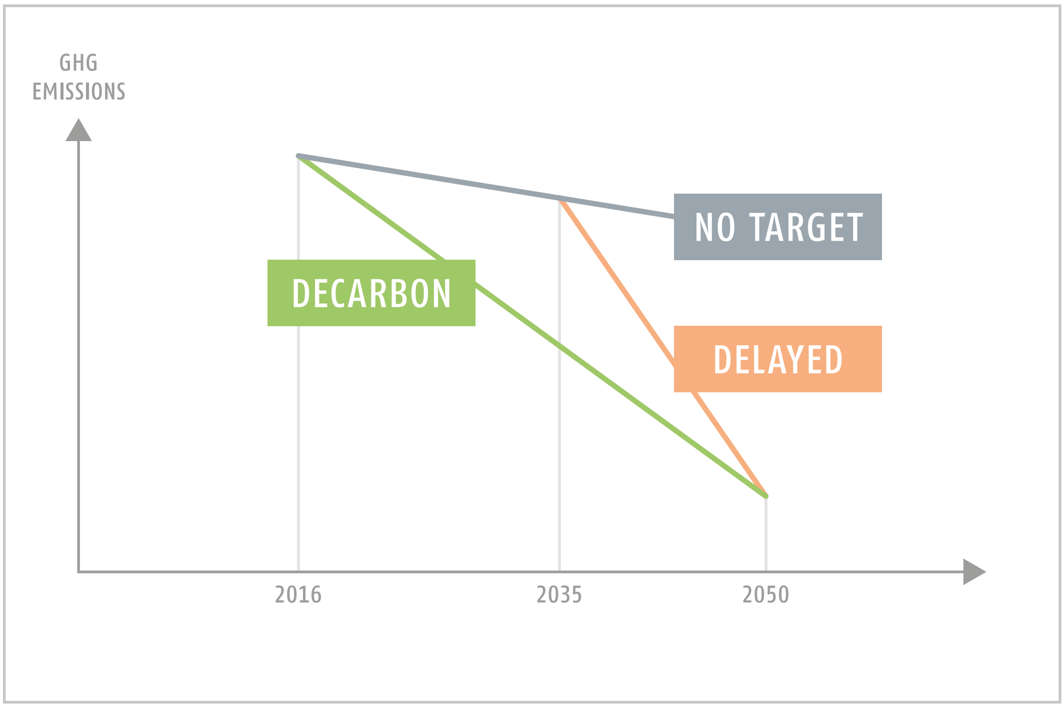
The modelling work does not take into account the impacts of the new Large Combustion Plant BREF (Commission Implementing Decision of 2017/1442), as it entered into force in July 2017.

The same emission reduction target of 94% was set for the EU28+WB6 region in the 'delayed' and 'decarbonisation' scenarios. This implies that the emission reductions will be higher in some countries and lower in others, depending on where emissions can be reduced most cost-efficiently.

The scenarios differ with respect to the mix of new technologies, included in the model in one of two ways: (i) the new power plants entered exogenously into the model based on policy documents, and (ii) the different levels and timing of RES support resulting in different endogenous RES investment decisions. The assumptions of the three core scenarios are the following:

- In the 'no target' scenario all currently planned fossil fuel power plants are entered into the model exogenously. Information on planned power plants is taken from official national strategies/plans and information received from the local partners involved in the project. We have assumed the continuation of current renewable support policies up to 2020 and the gradual phasing out of support between 2021 and 2025. The scenario assumes countries meet their 2020 renewable target but do not set a $CO_2$ emission reduction target for 2050. Although a $CO_2$ target is not imposed, producers face $CO_2$ prices in this scenario, as well as in the others.
- In the 'decarbonisation' scenario, only those planned investments which had a final investment decision in 2016 were considered, resulting in lower exogenous fossil fuel capacity.

**FIGURE 2**
THE CORE SCENARIOS




With a 94% $CO_2$ reduction target, RES support in the model was calculated endogenously to enable countries to reach their decarbonisation target by 2050 with the necessary renewable investment. RES targets are not fulfilled nationally in the model, but are set at a regional level, with separate targets for the SEERMAP region and for the rest of the EU.

- The 'delayed' scenario considers that currently planned power plants are built according to national plans, similarly to the 'no target' scenario. It assumes the continuation of current RES support policies up to 2020 with a slight increase until 2035. This RES support is higher than in the 'no target' scenario, but lower than the 'decarbonisation' scenario. Support is increased from 2035 to reach the same $CO_2$ emission reduction target as the 'decarbonisation' scenario by 2050.

Due to the divergent generation capacities, the scenarios result in different generation mixes and corresponding levels of $CO_2$ emissions, but also in different investment needs, wholesale price levels, patterns of trade, and macroeconomic impacts.

## 4.2 Main assumptions

All scenarios share common framework assumptions to ensure the comparability of scenarios with respect to the impact of the different investment strategies over the next few decades. The common assumptions across all scenarios are described below.

**Demand:**

- Projected electricity demand is based – to the extent possible – on data from official national strategies. Where official projections do not exist for the entire period until 2050, electricity demand growth rates were extrapolated based on the EU Reference scenario for 2013 or 2016 (for non-MS and MS respectively). For Romania we used a demand projection up to 2050 provided by the local partners that foresees an average annual electricity growth rate of 0.7% over the period 2015 to 2050.

- Demand side management (DSM) measures were assumed to shift 3.5% of total daily demand from peak load to base load hours by 2050. The 3.5% assumption is a conservative estimate compared to other projections from McKinsey (2010) or TECHNOFI (2013). No demand side measures were assumed to be implemented before 2035.

**Factors affecting the cost of investment and generation:**

- Fossil fuel prices: Gas prices are derived from the EGMM model while the price of oil and coal were taken from IEA (2016) and EIA (2017) respectively. The price of coal is expected to increase by approximately 15% between 2016 and 2050; in the same period gas prices increase by around 84% and oil prices by around 250%, because of historically low oil prices in 2016. Compared to 2012-2013 levels, this way only 15-20% increase in oil prices is assumed by 2050.
- Cost of different technologies: Information on the investment cost of new generation technologies is taken from EIA (2017).
- Weighted average cost of capital (WACC): The WACC has a significant impact on the cost of investment, with a higher WACC implying a lower net present value and therefore a more limited scope for profitable investment. The WACCs used in the modelling are country-specific, these values are modified by technology-specific and policy instrument-specific risk factors. The country-specific WACC for Romania is 10.1-10% over the whole period. The estimated WACC for onshore wind and PV is somewhat higher than the estimations of Ecofys – Eclareon (2017) foreseeing 7-9.5% for both technologies.
- Carbon price: a price for carbon is applied for the entire modelling period for EU member states and from 2030 onwards in non-member states, under the assumption that all candidate and potential candidate countries will implement the EU Emissions Trading Scheme or a corresponding scheme by 2030. The carbon price is assumed to increase from 33.5 EUR/t$CO_2$ in 2030 to 88 EUR/t$CO_2$ by 2050, in line with the EU Reference Scenario 2016. This Reference Scenario reflects the impacts of the full implementation of existing legally binding 2020 targets and EU legislation, but does not result in the ambitious emission reduction targeted by the EU as a whole by 2050. The corresponding carbon price, although significantly higher than the current price, is therefore a medium level estimate compared with other estimates of EU ETS carbon prices by 2050. For example, the Impact Assessment of the Energy Roadmap 2050 projected carbon prices as high as 310 EUR under various scenarios by 2050 (EC 2011b). The EU ETS carbon price is determined by the marginal abatement cost of the most expensive abatement option, which means that the last reduction units required by the EU climate targets will be costly, resulting in steeply increasing carbon price in the post 2030 period.

**Infrastructure:**

- Cross-border capacities: Data for 2015 was available from ENTSO-E with future NTC values based on the ENTSO-E TYNDP 2016 (ENTSO-E 2016) and the 100% RES scenario of the E-Highway projection (ENTSO-E 2015b).
- New gas infrastructure: In accordance with the ENTSO-G TYNDP 2017 both the Transadriatic (TAP) and Transanatolian (TANAP) gas pipelines (see Annex 2) are built between 2016 and 2021, and the expansion of the Revithoussa and the establishment of the Krk LNG

terminals are taken into account. No further gas transmission infrastructure development was assumed in the period to 2050.

**Renewable energy sources and technologies:**

- Long-term technical RES potential is estimated based on several factors including the efficiency of conversion technologies and GIS-based data on wind speed and solar irradiation, and is reduced by land use and power system constraints. It is also assumed that the long term potential can only be achieved gradually, with renewable capacity increase restricted over the short term. A sensitivity analysis measured the reduced potential of the most contentious RES capacities, wind and hydro. The results of the sensitivity analysis are discussed in section 5.5.
- Capacity factors of RES technologies were based on historical data over the last 5 to 8 years depending on the technology.

Annex 2 contains detailed information on the assumptions.

# 5 | Results

## 5.1 Main electricity system trends

Romania is the only country in the SEERMAP region where nuclear power will play a role in replacing current coal and gas capacities alongside investment in renewables and new gas capacity. The capacity of the Cernavoda plant is planned to be extended in 2028 by an additional 1400 MW.

The model results show that the least cost capacity options under the assumed costs and prices, assuming the contruction of the new nuclear power plant, are almost exclusively renewables (primarily wind and solar, and some biomass) in the scenarios with an emission reduction target, and a mix of natural gas and renewables in the 'no target' scenario. The changes in the capacity mix are driven primarily by increasing carbon prices and decreasing renewable technology costs. Coal based electricity generation disappears in all scenarios after 2030 in accordance with national plans. Model results confirm that coal is not a cost-efficient generation option in Romania.

Renewables play an increasingly important role in all three scenarios. New wind capacity investment is particularly strong, almost tripling by 2050 in the 'delayed' scenario and also increasing significantly in the 'decarbonisation' scenario, due to a combination of high wind potential, decreasing cost of technology and the price of carbon. New solar investments increase at an even higher rate, reaching five times 2016 levels by 2050 in the 'decarbonisation' scenario, but in absolute terms solar additions are more moderate, and the same applies to biomass. Meanwhile hydro capacity increases by approximately 20% across the period in both the 'delayed' and 'decarbonisation' scenarios.

Natural gas plays a transitory role in electricity generation, peaking in 2040-2045 across all three scenarios. The initial increase in gas based generation is driven by the rising price of carbon, which prices out coal and lignite based generation in the SEERMAP

**FIGURE 3**
INSTALLED CAPACITY IN THE 3 CORE SCENARIOS UNTIL 2050 (GW) IN ROMANIA, 2020-2050

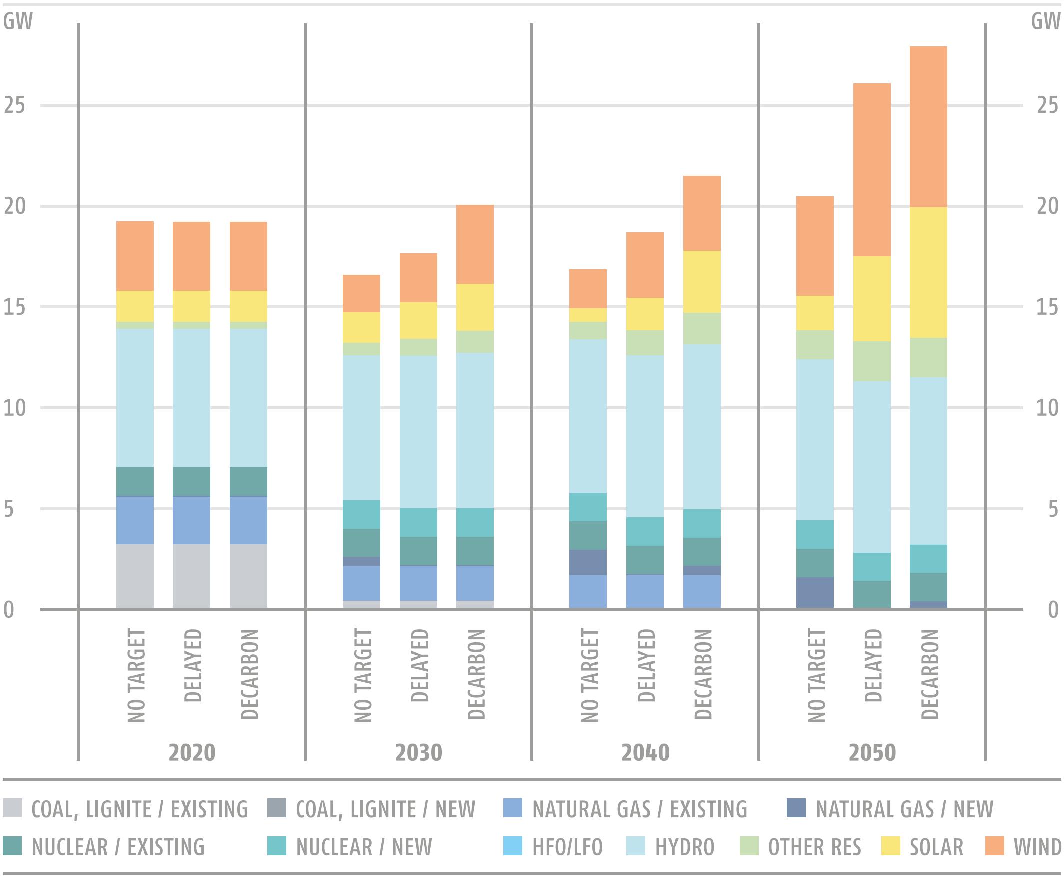



**FIGURE 4**
ELECTRICITY GENERATION AND DEMAND (TWh) AND RES SHARE (% OF DEMAND) IN ROMANIA, 2020-2050

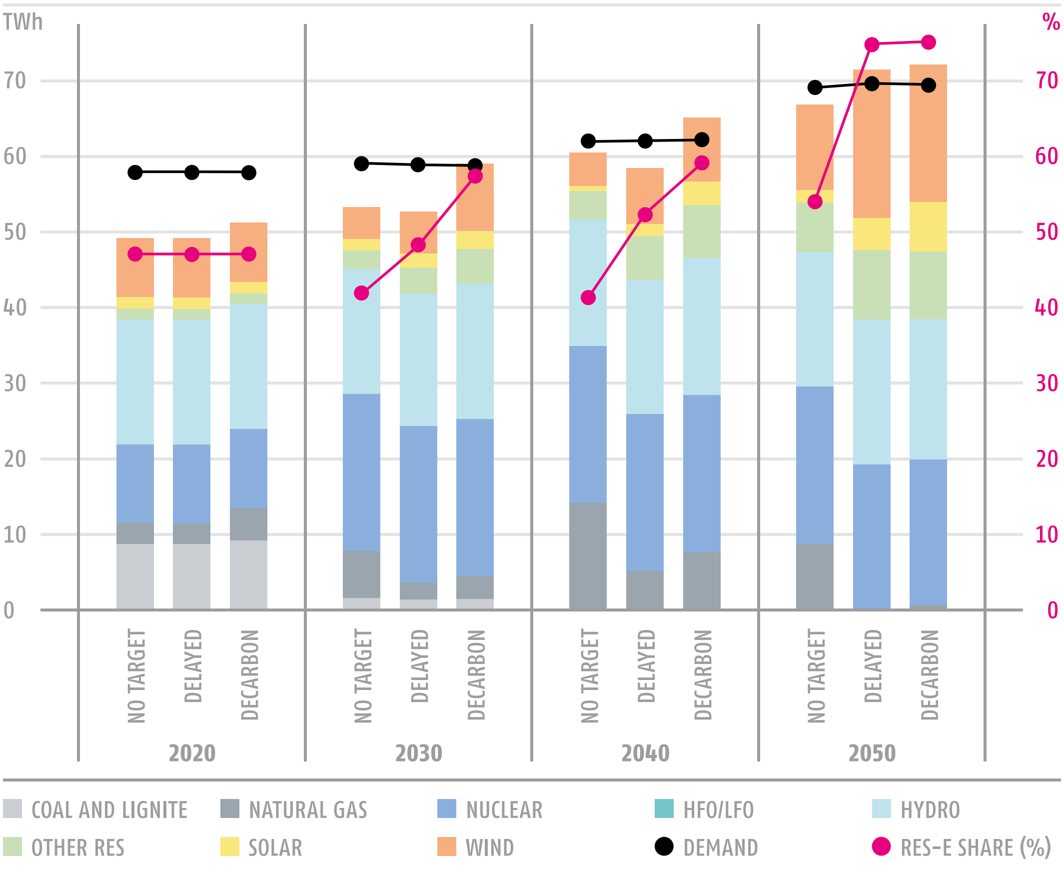
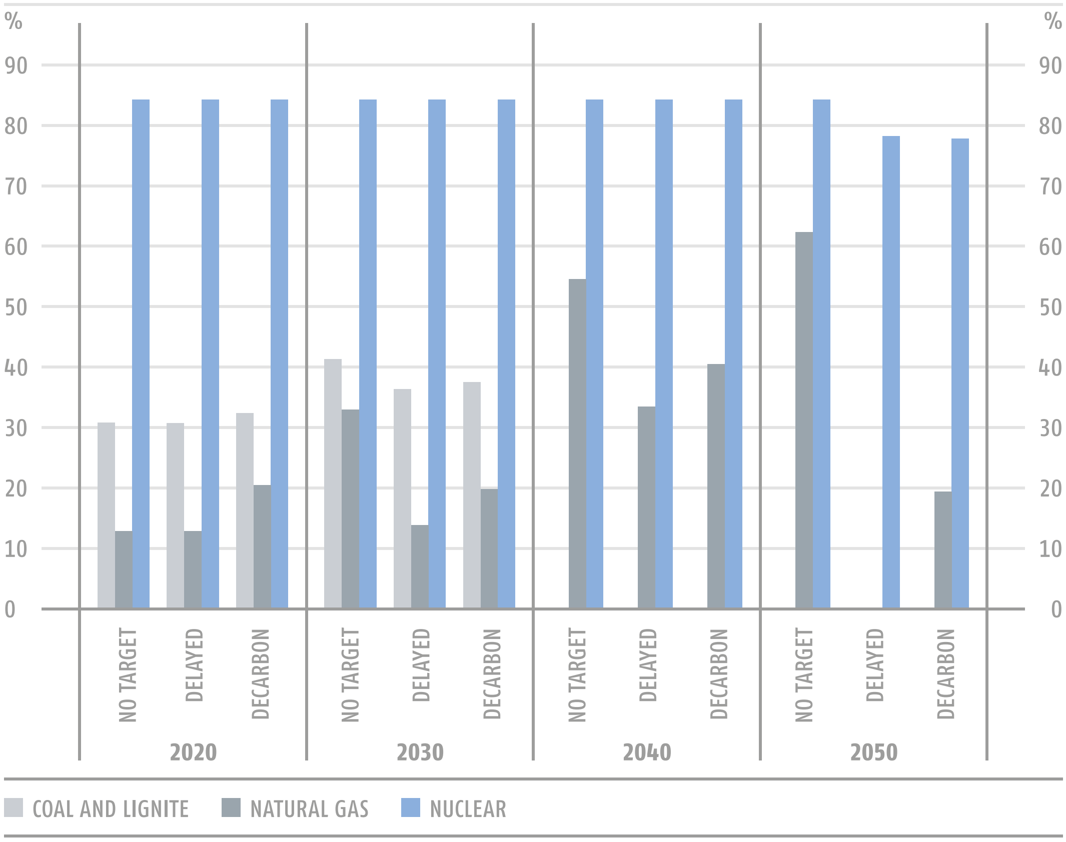


**FIGURE 5**
UTILISATION RATES OF CONVENTIONAL GENERATION IN ROMANIA, 2020-2050 (%)




region before sufficient renewable capacity is installed. Later on gas based generation falls as the carbon price continues to rise and renewable technologies become cheaper.

Natural gas investments are mostly limited to the 'no target' scenario, during which old capacities are partially replaced over time, but by 2050 gas generation capacity is projected to be half of 2016 levels. The corresponding large increase in natural gas based generation is a result of higher utilisation rates (above 50% from 2040). However, gas based generation drops between 2041 and 2050 to 13% of total electricity generation by the end of the modelled time horizon.

Contrary to the 'no target' scenario, in the 'delayed' and 'decarbonisation' scenarios gas based generation disappears after peaking in 2040. The temporary increase in gas based generation is achieved with increasing utilisation rates and only minor capacity additions.

Romania approaches – and in the 'delay' and " decarbonisation' scenarios eventually reaches – self-sufficiency over time due to the doubling of nuclear power generation, the temporary increase of gas based generation and the uptake of renewables.

In the 'no target' scenario, the utilisation of coal capacities increases from 2020 to 2030 but never reaches 40%. Gas utilisation rates grow continuously, with new gas capacities especially competitive in 2050 in this scenario, mainly due to the competitive pricing of domestic gas production. In the two emission reduction target scenarios, gas utilisation peaks at a lower level in 2040 and collapses thereafter due to a crowding out effect of policy driven renewable deployments. This shows that under an ambitious decarbonisation target the cost of gas generation investments made at the beginning of the modelled period can be recovered but investments made closer to 2040 may be stranded. Nuclear utilization also declines at the end of the period in these two scenarios due to the increasing renewable capacities.

## 5.2 Security of supply

Even though the physical and commercial integration between national electricity markets improves security of supply, decision makers often remain sceptical as to the extent and robustness of this improvement, particularly in the context of a high share of domestic renewables. In order to assess the validity of such concerns three security of supply indices were calculated for all countries and scenarios: the generation capacity margin, the system adequacy margin, and the cost of reducing the generation adequacy gap to zero.

The generation adequacy margin is defined as the difference between available capacity and hourly load as a percentage of hourly load. If the resulting value is negative then the load cannot be satisfied with domestic generation capacities alone in a given hour, and imports are needed. The value of the generation adequacy margin was calculated for all of the modelled 90 representative hours, and of the 90 calculated values, the lowest generation adequacy margin value was taken into account in the generation adequacy margin indicator. For this calculation, assumptions were made with respect to the maximum availability of different technologies: fossil fuel based power plants are assumed to be available 95% of the time, hydro storage 100% and for other RES technologies historical availability data was used. System adequacy was defined in a similar way, with net transfer capacity available for imports considered in addition to available domestic capacity. This is a simplified version of the methodology formerly used by ENTSO-E. (See e.g. ENTSO-E, 2015, and previous SOAF reports)

For Romania, the generation adequacy margin is positive throughout the entire modelling period, meaning domestic generation capacity is sufficient to satisfy domestic demand in all hours of the year for all years. The system adequacy margin is even higher.

In the case of negative initial generation adequacy values the cost of reaching a zero generation adequacy margin is calculated, defined as the yearly fixed cost of an open cycle gas turbine (OCGT) that brings the generation adequacy margin to zero. This can be interpreted as a capacity fee, provided that capacity payments are only made to new generation, and that the goal of the payment is to improve generation adequacy margin to zero. Since the generation adequacy margin for Romania was positive across all hours in all years, this cost is zero.

## 5.3 Sustainability

The $CO_2$ emissions of the three core scenarios were calculated based on representative emission factors for the region. Due to data limitations this did not account for greenhouse gases other than $CO_2$, and did not include emissions related to heat production from cogeneration.

The 94% overall decarbonisation target for the EU28+Western Balkans region translates into a higher than average level of decarbonisation in the Romanian electricity sector. By 2050, $CO_2$ emissions in the electricity sector in Romania compared with 1990 are reduced to virtually zero in the 'delayed' and 'decarbonisation' scenarios. This is due to new nuclear capacities entering operation in 2028. Emissions are also reduced significantly in the 'no target' scenario, exhibiting a 95.6% decrease by 2050 due to the high price of carbon and natural gas.

The share of renewable generation as a percentage of gross domestic consumption in the 'no target' scenario 41.8% in 2030 and 54.1% 2050. For the 'delayed' and 'decarbonisation' scenarios is the RES share is 74.9% and 75.2% respectively in 2050. The utilisation of technical RES potential is highest in the 'decarbonisation' scenario, reaching 32% hydro, 45% wind and 38% solar – still less than half of the RES potential by the end of the modelled period.

**FIGURE 6**
GENERATION AND SYSTEM ADEQUACY MARGIN FOR ROMANIA, 2020-2050 (% OF LOAD)

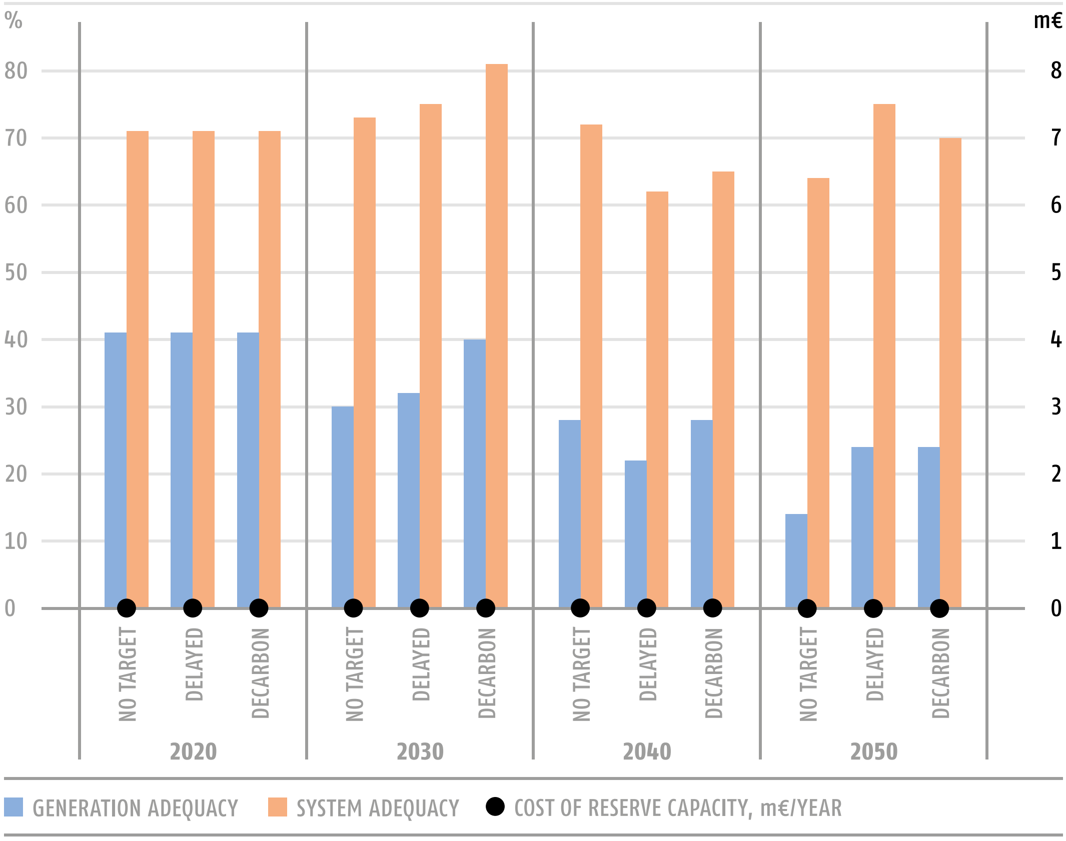
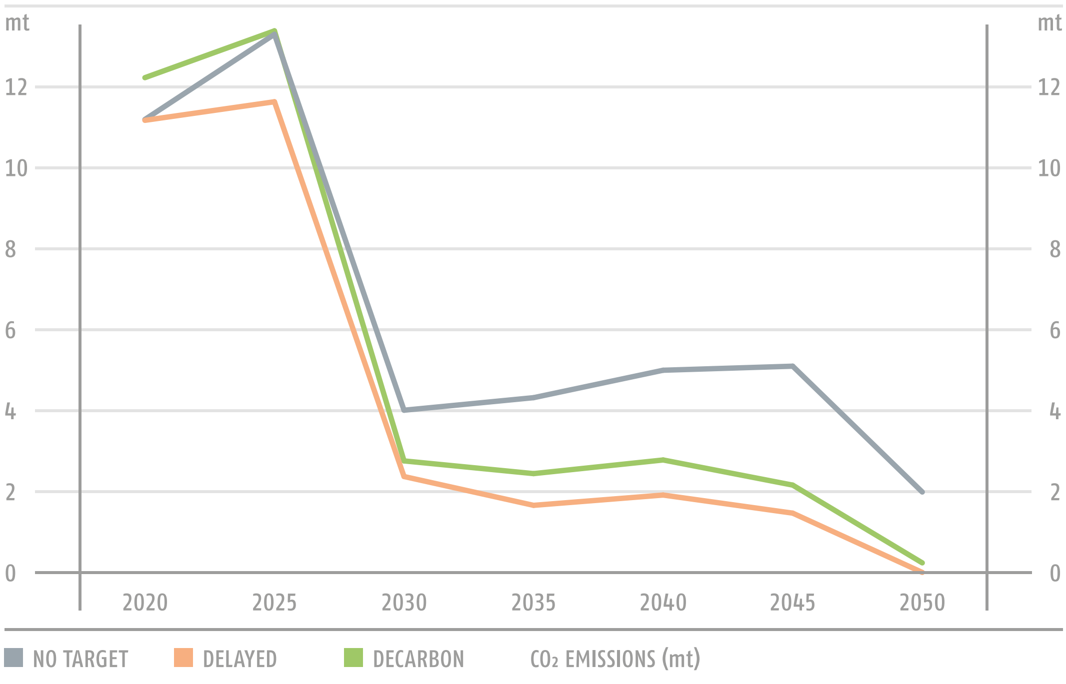



**FIGURE 7**
$CO_2$ EMISSIONS UNDER THE 3 CORE SCENARIOS IN ROMANIA, 2020-2050 (mt)



## 5.4 Affordability and competitiveness

In the market model (EEMM) the wholesale electricity price is determined by the highest marginal cost of the power plants needed to satisfy demand. Over the modelled time period wholesale prices increase significantly, driven by an increase in the carbon price and price of natural gas. The price trajectories are independent of the level of decarbonisation and similar in all scenarios, only separating after 2045 when the two scenarios with decarbonisation targets result in lower wholesale prices. This is due to the fact that towards 2050 the share of renewables is high enough to satisfy demand in most hours at a low cost, driving the average annual price down.

The price development has several implications for policy makers. Retail prices depend on the wholesale price as well as taxes, fees and network costs. It is therefore difficult to project retail price evolution based on wholesale price information alone, but it is an important determinant that will affect affordability for consumers. The average annual price increase over the entire period is 2.9% in the 'no target' scenario and 2.2% in the 'delayed' and 'decarbonisation', with lower growth in the latter two scenarios due to a fall in wholesale prices over the last 5 years of the modelled time period. Although the price increase seems significant, prices in Europe were at historical lows in 2016 for the starting point of the analysis and will rise to approximately 60 EUR/MWh by 2030, similar to 10 years ago. Macroeconomic analysis, presented in Section 5.7, shows that if affordability is measured as the share of household electricity expenditure in disposable income, affordability deteriorates, with highest increases in expenditure by the end of the modelled time horizon in the 'delayed' scenario. At the same time higher prices incentivise investment in new generation and in energy efficiency, and reduce the need for RES support.

The investment needed in new capacities increases significantly over the entire modelled time period. High levels of investment needs arise earlier in the 'decarbonisation' scenario and later in the 'delayed' scenario; in the latter significant effort is needed to meet decarbonisation targets at the end of the period. Throughout the entire modelling period the investment needs are lowest in the 'no target' scenario.

Investments are assumed to be financed by private actors according to a profitability requirement (apart from the capacities planned in the national strategies), factoring in the different cost structure of renewables, i.e. higher capital expenditure and low operating expenditure in their investment decisions. From a social point of view, the consequences of the overall investment level are limited to the impact on GDP. The technology choice affects the net position of electricity trade and the gas trade position, with the higher share of renewables implying more net electricity exports and better gas trade position by the end of the period. This is discussed in more detail in section 5.7.

Despite the very significant investment needs associated with the two scenarios with an emission reduction target, the support needed to incentivise these investments is small in relative terms and decreases over time. In comparison with the wholesale price, the RES support needed to achieve almost complete decarbonisation of the electricity sector in the 'decarbonisation' and the 'no target' scenarios is negligible from 2021 onwards, while the 'delayed' scenario requires greater RES support in the 2040-2050 period.

Although RES technologies are already at grid parity in some locations with costs falling further, some support will still be needed in 2050 to incentivise new investment

**FIGURE 8**
WHOLESALE ELECTRICITY PRICE IN ROMANIA, 2020-2050 (€/MWh)

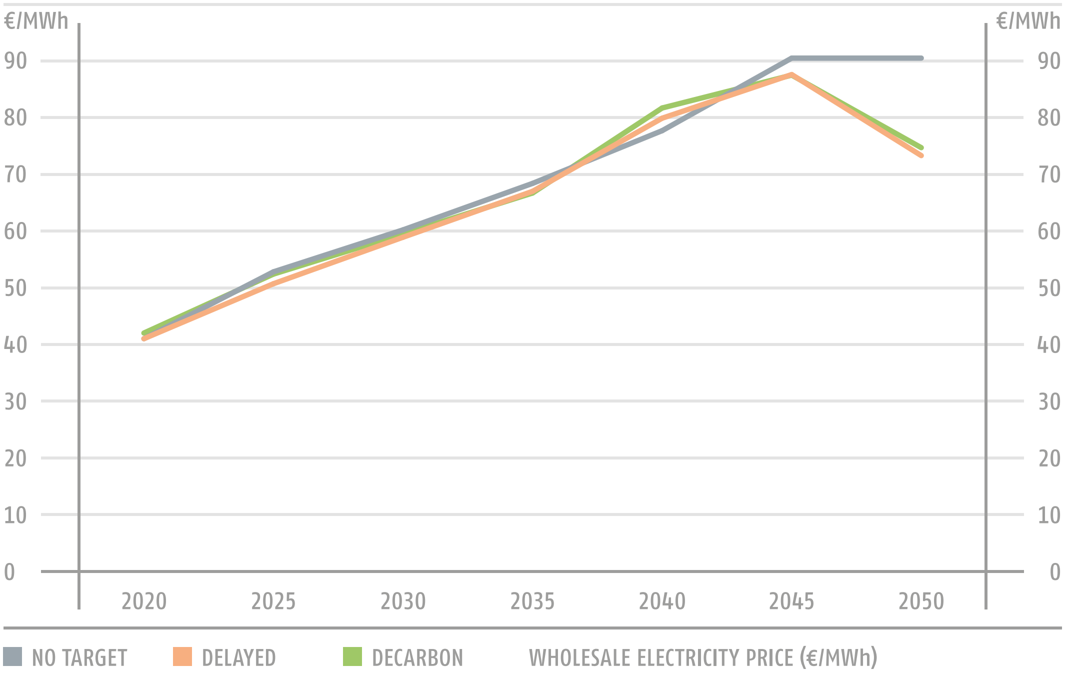



**FIGURE 9**
CUMULATIVE INVESTMENT COST FOR 4 AND 10 YEAR PERIODS, 2016-2050 (bn€)

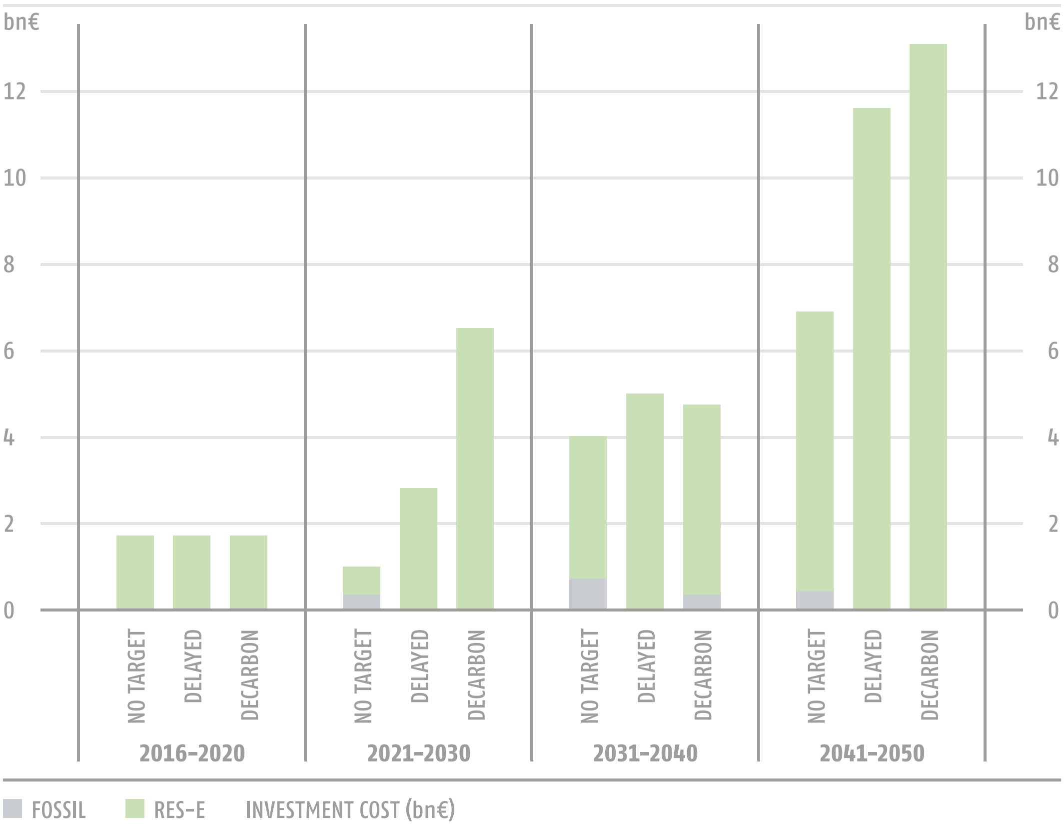
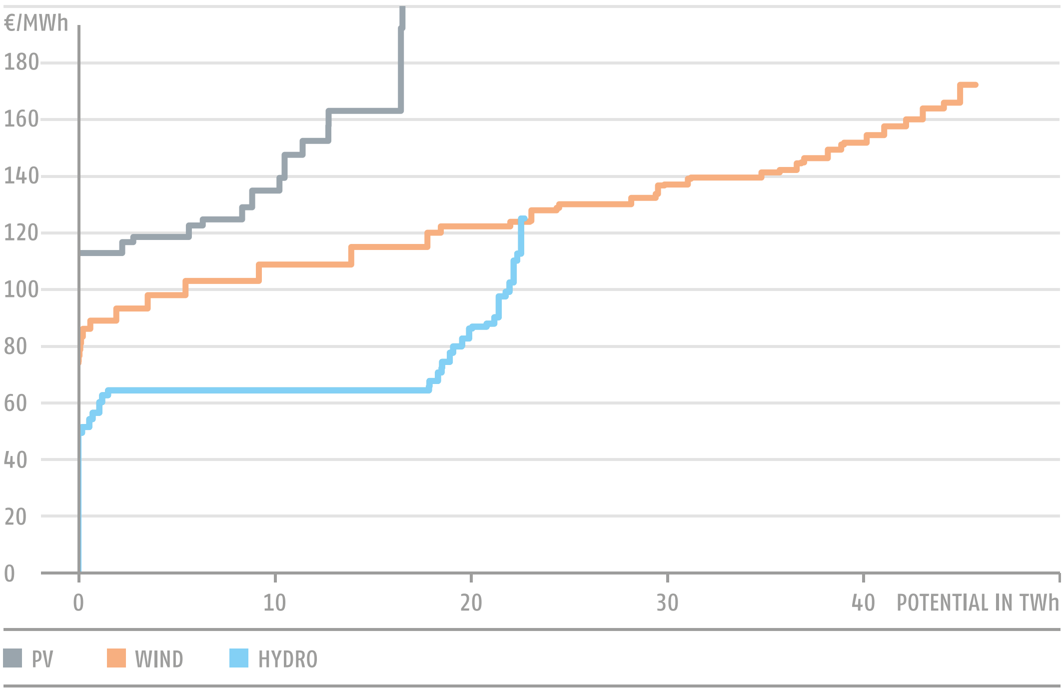


**FIGURE 10**
LONG TERM COST OF RENEWABLE TECHNOLOGIES IN ROMANIA (€/MWh)




because the best locations with highest potential are used first, and the levelised cost of new RES capacities increases over time. The relationship between the cost of RES technologies and installed capacity is shown in Figure 10; the figure does not account for the learning curve impacts which were also considered in the Green-X model.

With the exception of the last decade in the 'delayed' scenario, RES support decreases while investment in RES capacity increases over the entire period. The broad decline in RES support is made possible mainly by the increasing wholesale price for electricity which reduces the need for residual support.

Renewable energy investments may be incentivised through a variety of support schemes that secure funding from different sources, and in the model 'sliding' feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is one potential source of financing for this investment. Figure 12 compares cumulative RES support needs with ETS auction revenues, under an assumption of 100% auctioning and taking into account only allowances used in the electricity sector. In the 'decarbonisation' and 'delayed' scenarios, auction revenues decline significantly beginning in 2030 when higly emitting coal plants disappear from Romania's energy mix. Overall the modelling results show that ETS revenues can cover the necessary RES support from 2021 onwards in all scenarios with the exception of the end of the period the 'delayed' scenario.

For plants that were built in the period 2017-2050, a financial calculation was carried out to determine the stranded costs of fossil generation. New fossil generation capacities included in the scenarios are defined either exogenously by national energy strategy documents or are built by the investment algorithm of the EEMM endogenously. The investment module projects 10 years ahead, meaning that investors have limited knowledge of the policies applied in the distant future. The utilisation rate of coal generation assets drops below 15% and for gas generation below 25% in most SEERMAP countries by 2050. This means that capacities which generally need to have a 30-55

**FIGURE 11**
AVERAGE RES SUPPORT PER MWh OF TOTAL ELECTRICITY CONSUMPTION AND AVERAGE WHOLESALE PRICE, 2016-2050 (€/MWh)

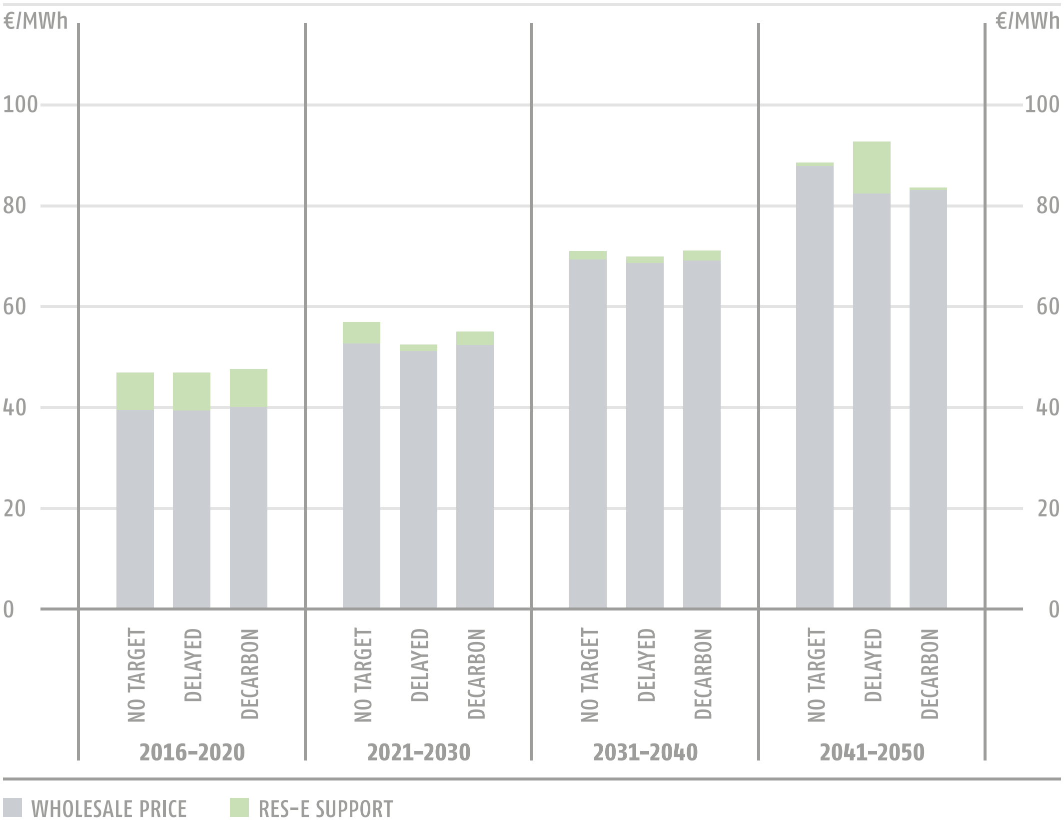
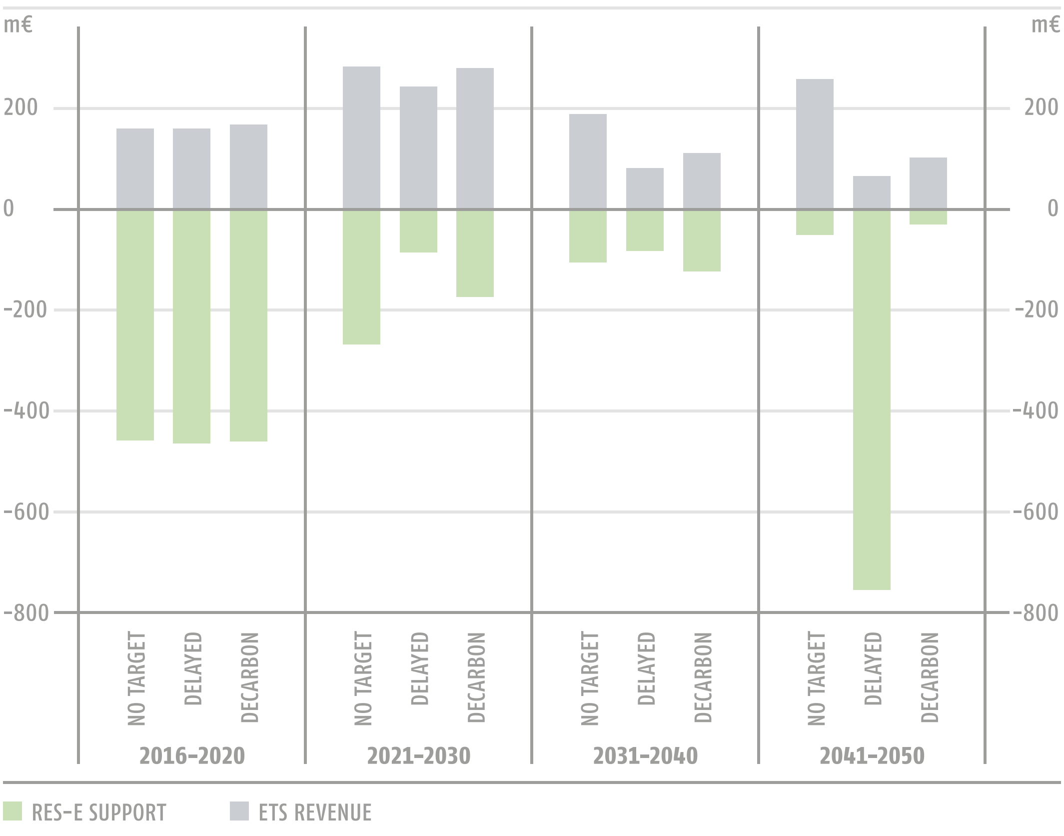



**FIGURE 12**
CUMULATIVE RES SUPPORT AND AUCTION REVENUES FOR 4 AND 10 YEAR PERIODS, 2016-2050 (m€)



year lifetime (30 for CCGT, 40 for OCGT and 55 for coal and lignite plants) with a sufficiently high utilisation rate in order to ensure a positive return on investment will face stranded costs. The phasing out of coal in Romania happens earlier than in the rest of the region, in accordance with national plans.

Large stranded capacities will likely require public intervention, whereby costs are borne by society or electricity consumers. Therefore, the calculation assumes that stranded cost will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) over a period of 10 years after gas and coal capacities finish their operation. Based on this calculation, early retired gas plants would add a 0.2 EUR/MWh surcharge over a 10 year period to cover their economic losses in the 'no target' scenario. Virtually no such cost applies to the 'delayed' and 'decarbonisation' scenarios due to the small new gas capacity additions and high utilisation rates. These costs are not included in the wholesale price values shown in this report.

## 5.5 Sensitivity analysis

The changes in assumptions in the sensitivity analysis were only applied to the 'decarbonisation' scenario since it represents a significant departure from the current policy for many countries. Therefore, it was important to test the robustness of results in order to convincingly demonstrate that the scenario could realistically be implemented under different framework conditions.

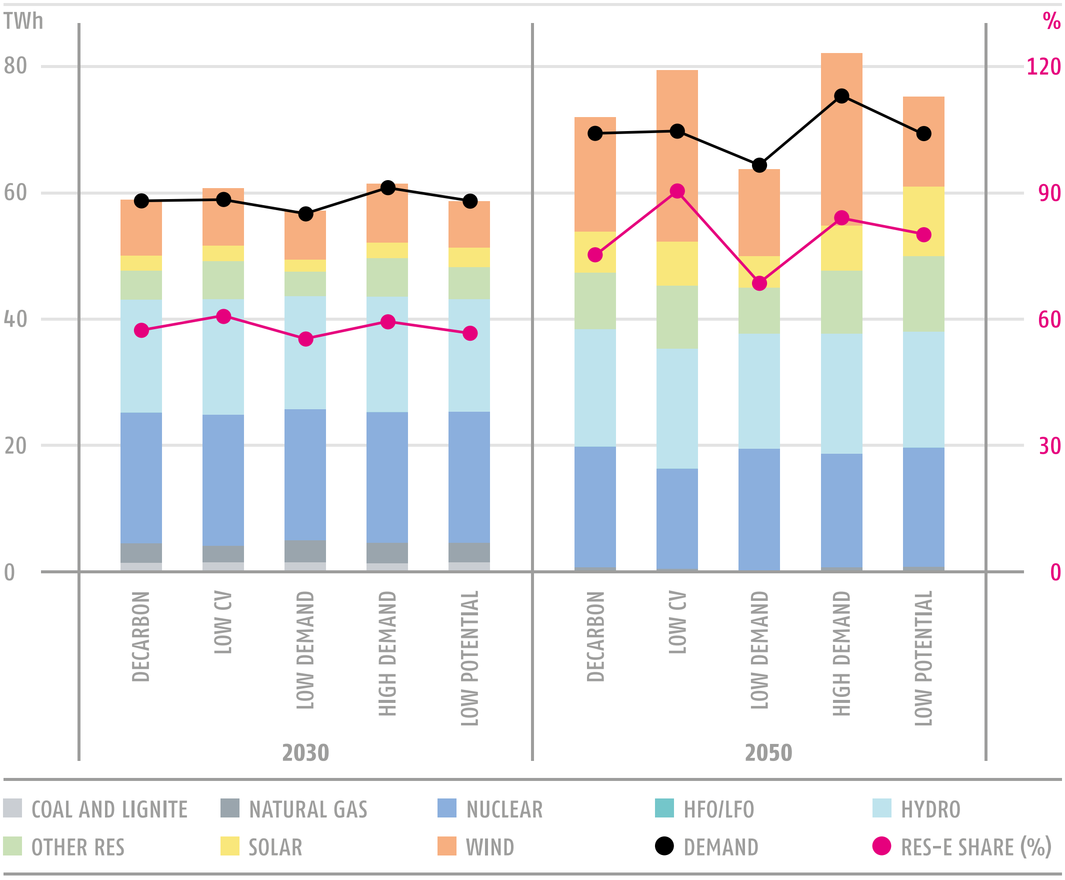
In order to assess the robustness of the results, sensitivity analyses were carried out to test the following assumptions that were considered controversial by stakeholders during consultations:

- Carbon price: to test the impact of a lower $CO_2$ price, a scenario was run which assumed that $CO_2$ prices would be half of the value assumed for the three core scenarios for the entire period until 2050;
- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the growth rate for each year in all the modelled countries (EU28+WB6), resulting in a 8-9% deviation from the core trajectory by 2050;
- RES potential: the potential for large-scale hydropower and onshore wind power were assumed to be 25% lower than in the core scenarios; this is where the NIMBY effect is strongest and where capacity increase is least socially acceptable.

The most important conclusions of the sensitivity analysis are the following:

- The $CO_2$ price is a key determinant of wholesale prices, with a 50% reduction in carbon price resulting in a reduction in the wholesale price by approximately one third over the long term. However, in order to ensure that the same decarbonisation target is met, higher RES support is required in this scenario. As a result, the sum of the wholesale price and RES support is higher in this run than in the decarbonisation scenario.
- A lower carbon price results in some changes in the generation mix; however, a low carbon price which is half of the level assumed in the 'decarbonisation' scenario is still insufficiently low to make lignite and coal based generation profitable in Romania.
- Assuming high demand, a similar generation mix results as under a low carbon price scenario. Demand variation is mostly met by variation in wind generation.

**FIGURE 13**
GENERATION MIX (TWh) AND RES SHARE (% OF DEMAND) IN THE SENSITIVITY RUNS IN 2030 AND 2050




- Lower hydro and wind potential results in increased solar and biomass generation. It also results in significantly higher RES support needed to achieve the same level of decarbonisation, as solar and biomass are higher cost RES technologies than wind and hydro.

## 5.6 Network

Romania's transmission system is already well-connected with its neighbouring countries. In the future additional network investments are expected to be realised to accommodate higher RES integration and cross-border electricity trade and to meet significant growth in peak load. The recorded peak load for Romania in 2016 was 8,752 MW (ENTSO-E DataBase), while it is projected to be 8,696 MW in 2030 (SECI DataBase) and 10,279 MW in 2050. Consequently, investment in both the transmission and distribution network will be needed.

For the comparative assessment, a 'base case' network scenario was constructed with development according to the SECI baseline topology and trade flow assumptions. The network effect of the higher RES deployment futures ('delayed' and 'decarbonisation' scenarios) were compared to this 'base case' scenario.

The network analysis covered the following ENTSO-E impact categories:

- **Contingency analysis:** Analysis of the network constraints anticipates contingencies at the Eastern part of the country; addressing these would require an estimated investment of 117 mEUR.

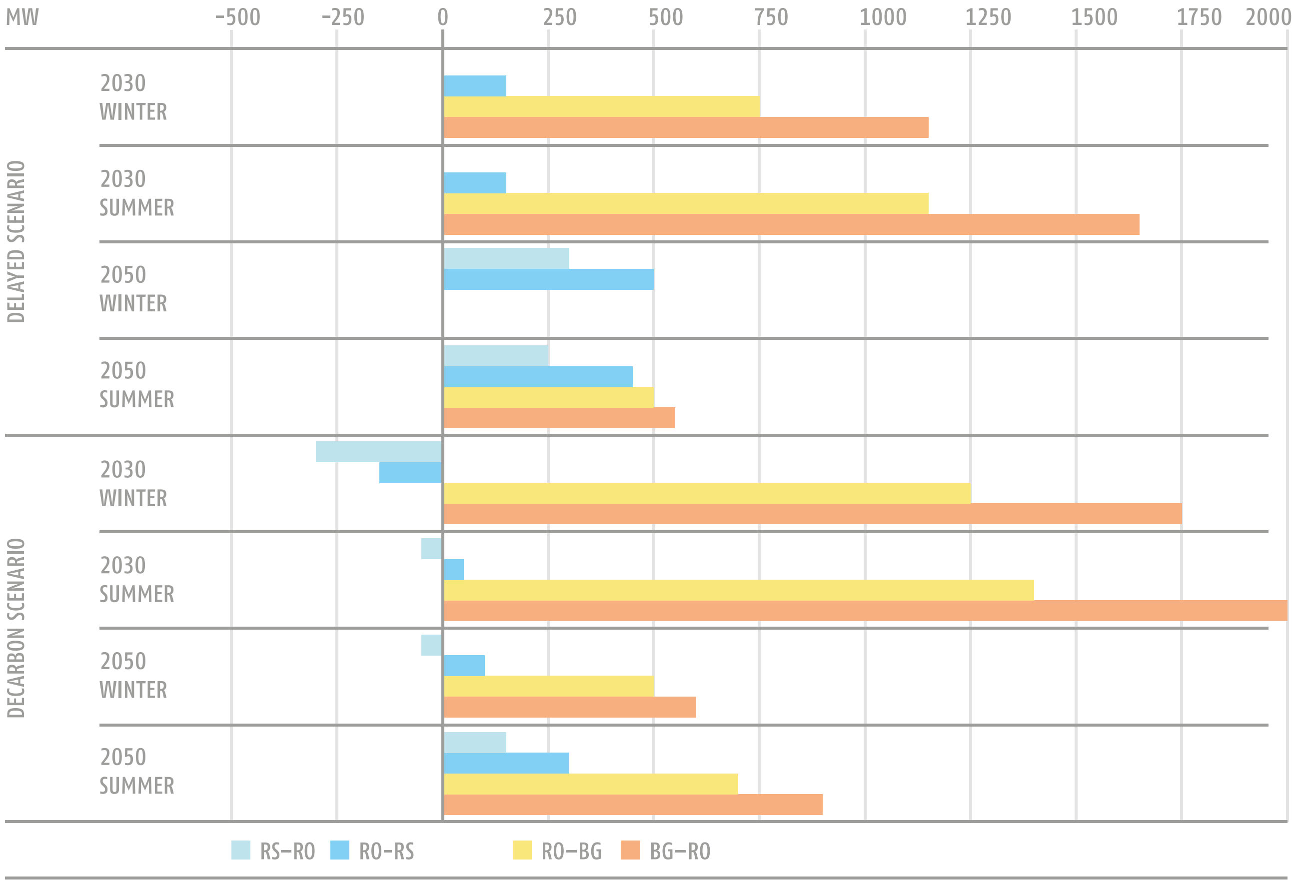



**FIGURE 14**
NTC VALUE CHANGES IN 2030 AND 2050 IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS COMPARED TO THE 'BASE CASE' SCENARIO

**TABLE 1 | OVERLOADINGS IN THE ROMANIAN SYSTEM, 2030**

| Overloading | Solution | Units (km or pcs) | Cost m€ |
|---|---|---|---|
| OHLs 110 kV in the area of Tulcea West (RO) | New single circuit OHL 400 kV Gadalin (RO) – Sucaeva (RO) enables RES penetration from WF | 260 | 52 |
| OHLs 110 kV in the area of east part of Romania with RESs | New 400kV double circuit OHL (one circuit wired) between existing substations, Smardan (RO) – Gutinas (RO) | 140 | 65 |

- **TTC and NTC assessment**: Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between Romania and all of its neighbours for all scenarios relative to the 'base case' scenario. The production pattern (including the production level and its geographic distribution) and load pattern (load level and its geographical distribution, the latter of which is not known) have a significant influence on NTC values between Romania and Bulgaria. Figure 14 presents the changes in NTC values for 2030 and 2050. Typically, two countervailing effects of higher RES deployments can be distinguished on the NTC values. First, the high concentration of RES within a geographic area may cause congestion of the transmission network, reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity

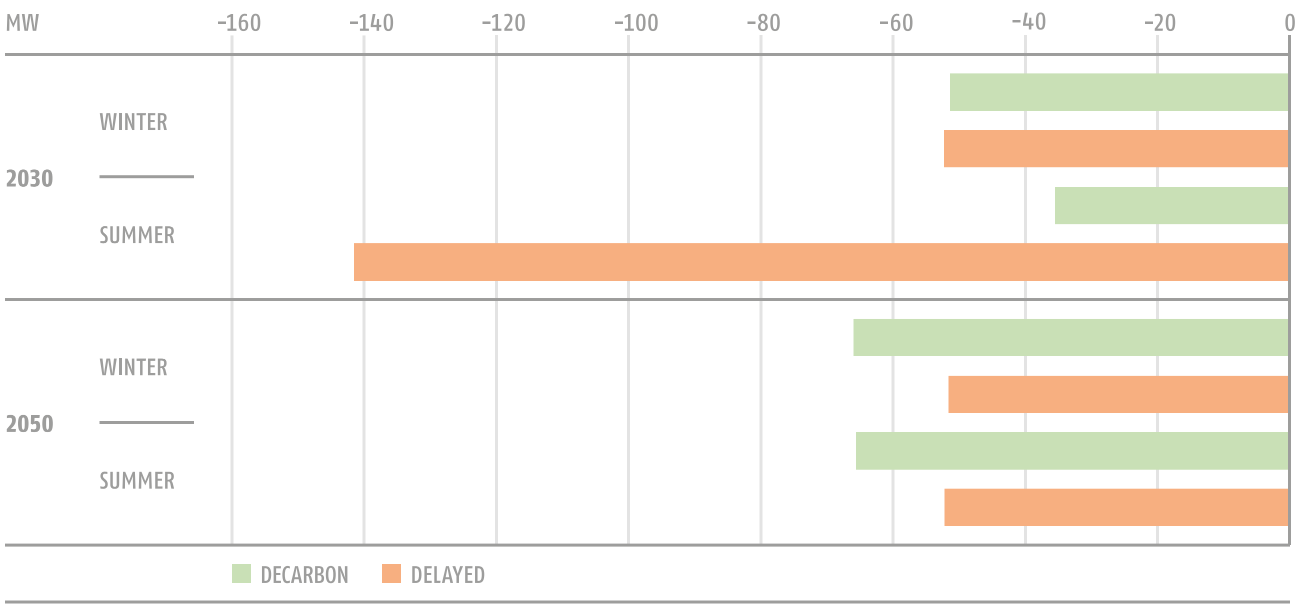



**FIGURE 15**
LOSS VARIATION COMPARED TO THE BASE CASE IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS (MW, NEGATIVE VALUES INDICATE LOSS REDUCTION)

it may increase NTC for a given direction. NTC values for Romania broadly increase as Romania becomes self-sufficient by 2050 in both scenarios.

- **Network losses:** Transmission network losses are affected in different ways. For one, losses are reduced as renewables, especially PV, are connected to the distribution network, reducing the physical distance between generation and consumption. However, high levels of electricity trade increase transmission network losses. The figures show that the effect of higher renewable generation is stronger in Romania resuting in lower losses.

As figure 15 illustrates, the higher RES deployment in the two scenarios reduces transmission losses in the modelled hours by around 50 MW in 2030 and 2050, with the exception of the 'delayed' scenario in 2030 when loss reduction is 140 MW. For the 'decarbonisation' scenario loss reductions of 214 GWh occur in 2030 and 447 GWh in 2050, while in the 'delayed' scenario loss reductions are 318 GWh in 2030 and 251 GWh in 2050. If monetised at the baseload price, the TSO can benefit over 18 mEUR per year.

## 5.7 Macroeconomic impacts

A 'baseline' scenario differing from the three core scenarios was constructed for the macroeconomic analysis to serve as a basis for comparison in which only power plants with a final investment decision by 2016 are built, investment rates in the sector remain unchanged for the remaining period, no decarbonisation targets are set, no additional renewable support is included beyond existing policies, and lower levels of investment are assumed.

Despite the strong economic performance in recent years, GDP growth in Romania is expected to slow gradually to 1.5% in the 2026-2050 period, reflecting low investment rates (partly as the absorption of EU funds diminishes) and a challenging


**FIGURE 16**
GDP AND EMPLOYMENT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

business environment. Both government and external debt will likely remain roughly at the current level of 40% of GDP throughout the modelled horizon.

Household electricity expenditure to income of 1.7% is much lower than the typical ratio in the region because Romania is more economically developed than the SEERMAP average. A projected increase of household electricity expenditure in the 'baseline' scenario is mostly driven by increasing real wholesale electricity prices, counteracted, to a degree, by declining renewable subsidies and income growth.

Additional investment efforts are moderate in the three core scenarios compared with the 'baseline' scenario, and even in the most intensive periods the additional investment is below 0.5% of GDP. The investment profile in the 'no target' scenario does not deviate from the baseline, while in the 'decarbonisation' scenario the investment intensive period starts after 2020 and is relatively persistent. In the 'delayed' scenario there are two investment peaks, from 2021-2025 and 2036-2050.

The macroeconomic results were assessed along three dimensions: macroeconomic gain, macroeconomic vulnerability, and affordability. Macroeconomic gain explains the extent to which the scenarios contribute to greater overall economic activity, measured by GDP and employment across two time dimensions. First, the average difference over the whole time horizon (2016-2050) is compared with the baseline. Then the long term effect is determined by the deviation from the baseline in the 2046-2050 period. It is important to stress that because the population remains the same across scenarios, GDP gains also reflect GDP per capita effects.

Overall, the results suggest that moderate macroeconomic gains result from the core scenarios. In the 'decarbonisation' scenario, the GDP level is on average 0.7% higher until 2050 compared to the 'baseline' scenario. The long term GDP effect is somewhat higher at 1.4%. Gains are more moderate in the 'delayed' scenario (around 0.3% on average and 0.8% in the long term), while practically zero in the 'no target' scenario. Employment effects are muted at around 0.1% on average compared to the 'baseline' scenario in the 'decarbonisation' and 'delayed' scenarios, slightly increasing

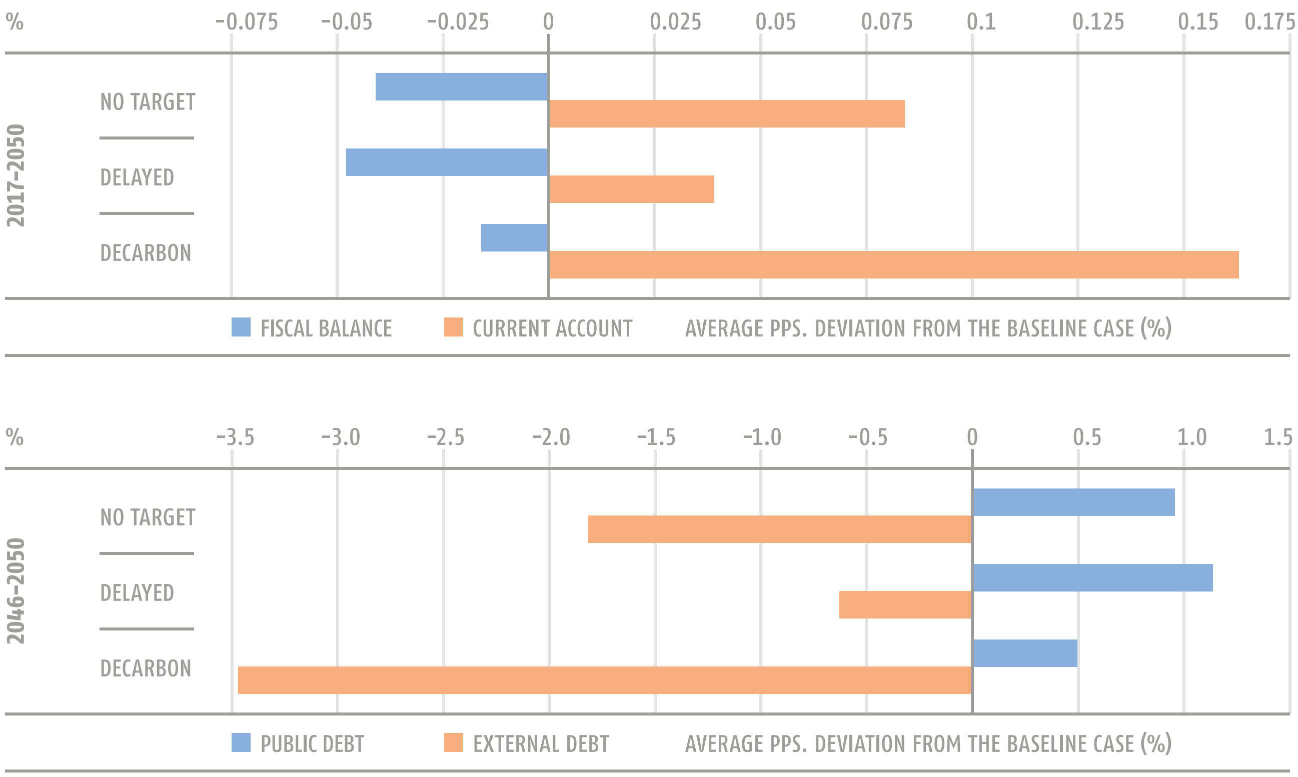



**FIGURE 17**
PUBLIC AND EXTERNAL BALANCES AND DEBT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

in the long term. At the same time, the 'no target' scenario has practically no effect on the economy.

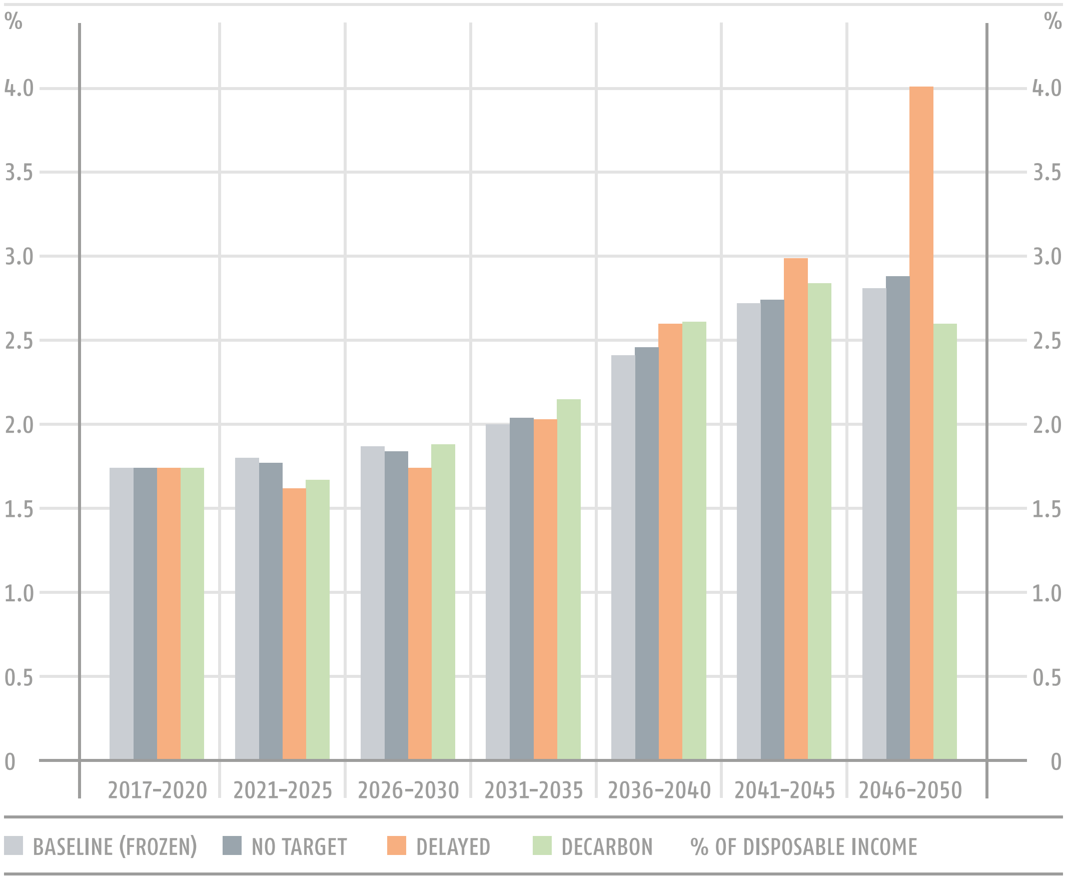
Long term GDP gains in the 'decarbonisation' and 'delayed' scenarios result from two sources. The additional investment compared to the 'baseline' raises the level of productive capital in the economy and the newly installed, mostly foreign technologies, increase overall productivity. The employment gains are lower compared to the GDP effect because of two factors: (i) the energy investments are relatively capital intensive and (ii) the initial employment gains are translated into higher wages in the longer term, as labour supply remains the same across scenarios.

The macroeconomic vulnerability calculation captures how additional investments contribute to the sustainability of the fiscal and external positions of the country. This is captured by the fiscal and external balances, as well as the public and external debt indicators. While the fiscal and the external balances are compared to the 'baseline' scenario over the whole projection horizon (2017-2050), the debt indicators focus only on the long term effects, and calculate the difference from the baseline only at the end of the modelled time horizon. This approach is consistent with the fact that debt is accumulated from past imbalances.

The core scenarios do not change the macroeconomic vulnerability of Romania significantly. The external debt declines by 0.5-3% of GDP in the long term, primarily as the result of a slightly improving current account balance due to lower energy imports compared to the baseline. Otherwise the effect on fiscal deficit and public debt is even smaller.

Affordability measures the burden of the electricity bill for households as the ratio of household electricity expenditure to household disposable income. The measure is tracked closely throughout the whole period in order to identify notable increases.

**FIGURE 18**
HOUSEHOLD ELECTRICITY EXPENDITURE 2017-2050




Affordability deteriorates in some periods for Romania in both the 'delayed' and the 'decarbonisation' scenarios if compared to the baseline. In the former case, household electricity expenditure to income increases by nearly 35% compared to the baseline in the final five year period, while in the latter it increases by 5% during the 2031-2045 period. At the same time, in the 'decarbonisation' scenario electricity expenditure to income declines by close to 10% in the 2046-2050 period due to the fall in wholesale electricity prices. This effect is counteracted in the 'delayed' scenario by a close to 45% increase in renewable subsidies. The 'no target' scenario does not differ substantially from the 'baseline'.

# 6 | Policy conclusions

The modelling work carried out under the SEERMAP project identifies some key findings with respect to the different strategic choices that Romania can take. We review these findings and suggest some policy related insights. The analysis has uncovered some robust findings which are relevant for all scenarios, based on which no regret policy options can be identified.

MAIN POLICY CONCLUSIONS

**Regardless of whether or not Romania pursues an active policy to decarbonise its electricity sector a significant shift away from fossil fuels will take place:**

- Coal plants will be phased out by 2030 in all scenarios in accordance with national plans; the model results also confirm that building new coal and lignite plants in Romania is not cost-efficient;
- Nuclear capacity will double (this is an exogenous assumption in the modeliing);
- Natural gas plays a transitional role on the path towards low carbon generation, peaking in 2040-2045 in the different scenarios;
- The currently high penetration of RES will increase further, reaching as high as 75% of consumption in the 'delayed' and 'decarbonisation' scenarios, due to an increase in wind, solar and biomass capacity;

**Long term planned RES support has some advantages compared with delayed or no action, but also presents some challenges:**

- The modelling demonstrates that it is technically feasible and financially viable for Romania to reach full decarbonisation of its electricity sector;
- Long term planned RES support does not drive up wholesale prices relative to other scenarios with less ambitious RES policies and actually reduces them after 2045;
- The 'decarbonisation' scenario will require more investment than the 'delayed' scenario but avoids the excessive level of RES support at the end of the modelled period;
- Private investment will have a positive effect on GDP growth by about 0.7% on average between 2017 and 2050 in the 'decarbonisation' scenario.

## 6.1 Main electricity system trends

Romania is the only country in the SEERMAP region that will replace its current coal and gas capacities not only with renewables and new gas units but also with nuclear power. In Romania, more than 80% of current fossil fuel generation capacity, approximately 6000 MW, is expected to be decommissioned by the end of 2030, and none of the current generation capacity will remain in operation by 2050. This provides both a challenge to ensure a policy framework which will incentivise needed new investment, and an opportunity to shape the electricity sector over the long term in-line with a broader energy transition unconstrained by the current generation portfolio.

**Whether or not Romania pursues an active policy to support renewable electricity generation, fossil fuel generation capacity will decline precipitously. Coal based generation is phased out according to national plans by 2030; model results confirm that coal is not a cost-efficient option, as no coal capacities are built by the model endogenously. Natural gas generation reaches its peak in**

**2040-2045, with the reduction towards the end of the modelled time horizon in gas based generation driven by a combination of high gas and carbon prices.**

With ambitious decarbonisation targets and corresponding RES support schemes, Romania will have an electricity mix with 75% renewable generation, mostly hydro and wind, by 2050. Absent a $CO_2$ emission reduction target and with renewable subsidies phased out under the 'no target' scenario, the share of RES in electricity consumption will reach only 54% in 2050. This represents a small increase from current levels.

**The increase of RES in all scenarios suggests that a robust no-regret action for the Romanian energy policy is to focus on enabling RES integration involving:**

- investing in transmission and distribution networks,
- enabling demand side management and RES production through a combination of technical solutions and appropriate regulatory practices, and
- promoting investment in storage solutions including hydro and small scale storage.

Natural gas will remain a relevant fuel source over the coming decades, increasing in all scenarios initially, with natural gas based generation peaking in 2040-2045. However, the role of natural gas is transitory in the scenarios with a decarbonisation target, disappearing from the electricity mix by 2050. In the 'no target' scenario new capacities operate with a high utilisation rate resulting in less stranded costs compared to other countries in the SEE region. **Still, the role for gas under the 'decarbonisation' and 'delayed' scenarios, the two scenarios in line with EU climate policy goals, is only temporary.**

**Delayed action in the rollout of renewables is feasible but leads to a disproportionate push for RES deployment towards the end of the modelled period requiring significantly more RES support and creating more of a household financial burden.**

## 6.2 Security of supply

Net electricity imports decrease over time in all scenarios, and Romania reaches self-sufficiency over time due to the doubling of nuclear power generation, the temporary increase of gas and the uptake of renewables in the 'delayed' and 'decarbonisation' scenarios. **Its generation and system adequacy indicators also remain favourable;** installed generation capacity within the country enables Romania to satisfy domestic demand using domestic generation in all seasons and hours of the day for the entire modelled period.

The network modelling results suggest that Romania would have to invest in the transmission and distribution network and cross-border capacity. The estimated level of investment needed in the Romanian transmission network system is 117 mEUR in addition to investments contained in ENTSO-E TYNDP 2016. These upgrades would allow for the integration of new capacities, increase crossborder capacities available for trade, and at the same time reduce network losses.

## 6.3 Sustainability

**The nuclear capacity extension and renewable potential** allows Romania to make an above average contribution to 2050 emission reduction targets. The electricity sector is fully decarbonised by 2050 in the scenarios with a $CO_2$ target and achieves a higher than 95% reduction in the 'no target' scenario compared to 1990 emission levels. RES potential can be realised through policies that eliminate barriers to RES investment. **No-regret steps involve measures enabling RES integration, as well as measures aimed at lowering investment costs, such as de-risking policies addressing the high cost of capital.**

## 6.4 Affordability and competitiveness

**An active policy supporting renewable generation in the electricity sector does not drive up wholesale electricity prices compared to a scenario where no emission reduction target is set.** The wholesale price of electricity is not driven by the level of decarbonisation but by the $CO_2$ price, which is applied across all scenarios, and the price of natural gas, which provides the marginal production needed to meet demand in a significant number of hours of the year for much of the modelled time period in all scenarios.

The wholesale price of electricity follows a similar trajectory under all scenarios and only diverges after 2045, when wholesale electricity prices in the two scenarios with a decarbonisation target fall due to a high share of low marginal cost RES in the electricity mix.

**All scenarios demonstrate a significant increase in the wholesale electricity price compared with current (albeit historically low) price levels.** This trend is observable across the SEE region and the EU as a whole in all scenarios for the modelled time period, driven by carbon and gas prices, both of which increase significantly by 2050. While higher wholesale prices will reach end consumers, it is also an important signal for attracting investment to replace retiring capacity. The macroeconomic analysis shows that despite the high absolute increase in wholesale prices, household electricity expenditure relative to household income remains limited in all scenarios due to gains in household disposable income and the low initial share of household electricity expenditure in total disposable income. It is important to note that the level and timing of changes in the household burden is scenario dependent and poses a shock in the 'delayed' scenario at the end of the modelled period.

**Decarbonisation will necessitate a very significant increase of investment in generation capacity. These investments are assumed to be financed by private actors** who accept higher investment costs in exchange for low operation (including fuel) and maintenance costs. From a broad societal point of view, the swell of investment has a positive impact on the GDP.

Although not modelled, **wholesale electricity price volatility is also expected to increase,** ceteris paribus, in scenarios with a higher shares of intermittent renewables. **Demand and supply side measures can reduce price volatility.** Governments will need to determine the acceptable level of price volatility in relation to the costs of supply and demand side measures and decide on appropriate policy measures.

High initial investment needs of RES technologies are extremely sensitive to the cost of capital, which is high in Romania compared with far lower values in Western

European member states. Although much of the value of the cost of capital depends on the country risk profile linked to broad macroeconomic performance, policymakers can reduce the cost of capital through interventions by ensuring a stable energy policy framework and establishing de-risking measures. These should be considered as no-regret steps that minimise system cost and consumer expenditures.

**Electricity decarbonisation consistent with EU targets requires continued RES support during the entire period until 2050 under all scenarios.** However, the need for support is capped by increasing electricity wholesale prices which incentivise significant RES investment even without support. Furthermore, a potentially significant share of the RES support can be covered from EU ETS revenues after 2031, thereby lowering the burden to consumers. **The need for long term RES support must be facilitated by long term evidence based policy planning,** to provide investors with the necessary stability to ensure that sufficient renewable investments will take place.

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# Annexes

# Annex 1 | Model output tables

## TABLE A1 | 'NO TARGET' SCENARIO

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Installed capacity, MW | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 450 | 850 | 1 250 | 1 250 | 1 600 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 029 | 7 199 | 7 369 | 7 625 | 7 791 | 7 991 |
| | Wind | | 3 026 | 3 435 | 3 434 | 1 851 | 481 | 1 929 | 3 003 | 4 958 |
| | Solar | | 1 317 | 1 534 | 1 534 | 1 534 | 1 030 | 692 | 1 075 | 1 696 |
| | Other RES | | 129 | 360 | 460 | 604 | 726 | 866 | 1 198 | 1 443 |
| Gross consumption, GWh | | | 54 795 | 57 980 | 58 941 | 59 121 | 59 670 | 61 974 | 64 695 | 69 108 |
| Net electricity generation, GWh | Total | | 53 881 | 49 227 | 53 847 | 53 297 | 54 532 | 60 512 | 65 714 | 66 893 |
| | Coal and lignite | | 13 778 | 8 758 | 9 570 | 1 596 | 0 | 0 | 0 | 0 |
| | Natural gas | | 4 382 | 2 716 | 6 139 | 6 215 | 12 044 | 14 131 | 14 380 | 8 749 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 776 | 20 776 | 20 776 | 20 776 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 16 527 | 16 527 | 16 527 | 16 746 | 17 252 | 17 845 |
| | Wind | | 6 998 | 7 832 | 7 830 | 4 222 | 1 097 | 4 399 | 6 849 | 11 306 |
| | Solar | | 1 359 | 1 543 | 1 543 | 1 543 | 1 036 | 696 | 1 082 | 1 707 |
| | Other RES | | 714 | 1 414 | 1 801 | 2 418 | 3 052 | 3 763 | 5 376 | 6 511 |
| Net import, GWh | Total | | 914 | 8 753 | 5 095 | 5 824 | 5 138 | 1 462 | -1 019 | 2 216 |
| | BG | | 1 298 | 7 031 | 4 295 | -523 | -2 552 | -7 264 | -6 514 | -6 637 |
| | HU | | -675 | 1 299 | -110 | 2 373 | 4 233 | 6 108 | 11 904 | 18 140 |
| | RS | | -968 | -581 | 171 | -1 305 | -1 020 | -2 775 | -9 226 | -11 561 |
| | UA_W | | 717 | 460 | 196 | 441 | 424 | 644 | 515 | 719 |
| | MD | | 543 | 543 | 543 | 4 839 | 4 053 | 4 750 | 2 302 | 1 555 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net import ratio, % | | | 1.7% | 15.1% | 8.6% | 9.9% | 8.6% | 2.4% | -1.6% | 3.2% |
| RES-E share (RES-E production/gross consumption, %) | | | 46.1% | 47.1% | 47.0% | 41.8% | 36.4% | 41.3% | 47.2% | 54.1% |
| Utilisation rates of RES-E technical potential, % | Hydro | | na | na | na | na | na | na | na | 31% |
| | Wind | | na | na | na | na | na | na | na | 28% |
| | Solar | | na | na | na | na | na | na | na | 10% |
| Utilisation rates of conventional power production, % | Coal and lignite | | 30.5% | 30.9% | 38.5% | 41.4% | na | na | na | na |
| | Natural gas | | 16.4% | 12.9% | 33.4% | 33.0% | 53.9% | 54.6% | 55.6% | 62.4% |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% |
| Natural gas consumption of power generation, TWh | | | 8.87 | 5.53 | 11.46 | 11.10 | 21.49 | 24.87 | 25.36 | 16.00 |
| Security of supply | Generation adequacy margin | | 65% | 41% | 37% | 30% | 26% | 28% | 27% | 14% |
| | System adequacy margin | | 82% | 71% | 72% | 73% | 76% | 72% | 77% | 64% |
| $CO_2$ emission | Emission, Mt $CO_2$ | | 17.8 | 11.2 | 13.3 | 4.0 | 4.3 | 5.0 | 5.1 | 2.0 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.8% | 75.4% | 70.7% | 91.2% | 90.5% | 89.0% | 88.8% | 95.6% |
| Spreads | Clean dark spread, €(2015)/MWh | | 16.3 | 14.9 | 18.9 | 14.8 | 13.5 | 13.9 | 6.5 | -13.6 |
| | Clean spark spread, €(2015)/MWh | | -3.2 | -1.1 | -0.7 | -1.6 | -1.1 | -2.2 | -0.8 | -8.3 |
| Price impacts | Electricity wholesale price, €(2015)/MWh | | 34.7 | 41.0 | 52.8 | 60.2 | 68.4 | 77.7 | 90.5 | 90.5 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 7.4 | 5.7 | 2.6 | 1.4 | 1.7 | 1.1 | 0.3 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 2.9 | 5.1 | 2.3 | 3.0 | 4.0 | 5.4 | 2.5 |
| Investment cost, m€/5 year period | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 46 | 0 | 367 | 367 | 365 | 0 | 444 |
| | Total Fossil | | na | 46 | 0 | 367 | 367 | 365 | 0 | 444 |
| | Total RES-E | | na | 1 689 | 220 | 419 | 554 | 2 742 | 2 595 | 3 874 |
| | Total | | na | 1 735 | 220 | 786 | 921 | 3 108 | 2 595 | 4 318 |
| Main assumptions | Coal price, €(2015)/GJ | | 1.78 | 1.95 | 1.93 | 1.89 | 1.98 | 2.04 | 2.04 | 2.04 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A2 | 'DELAYED' SCENARIO

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 0 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 418 | 7 588 | 7 758 | 8 032 | 8 187 | 8 492 |
| | Wind | | 3 026 | 3 436 | 4 000 | 2 443 | 1 173 | 3 244 | 5 533 | 8 592 |
| | Solar | | 1 317 | 1 534 | 1 795 | 1 795 | 1 494 | 1 608 | 2 652 | 4 201 |
| | Other RES | | 129 | 355 | 661 | 839 | 916 | 1 250 | 1 646 | 1 998 |
| **Gross consumption, GWh** | | | 54 795 | 57 981 | 58 978 | 58 900 | 59 779 | 62 088 | 65 250 | 69 676 |
| **Net electricity generation, GWh** | Total | | 53 878 | 49 189 | 54 101 | 52 695 | 50 762 | 58 476 | 65 901 | 71 453 |
| | Coal and lignite | | 13 777 | 8 742 | 8 872 | 1 403 | 0 | 0 | 0 | 0 |
| | Natural gas | | 4 380 | 2 708 | 3 681 | 2 140 | 4 457 | 5 140 | 3 939 | 0 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 776 | 20 776 | 20 743 | 19 267 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 17 515 | 17 515 | 17 515 | 17 779 | 18 258 | 19 119 |
| | Wind | | 6 998 | 7 837 | 9 121 | 5 571 | 2 675 | 7 398 | 12 617 | 19 593 |
| | Solar | | 1 359 | 1 543 | 1 806 | 1 806 | 1 503 | 1 617 | 2 668 | 4 227 |
| | Other RES | | 714 | 1 396 | 2 671 | 3 485 | 3 836 | 5 766 | 7 675 | 9 248 |
| **Net import, GWh** | Total | | 917 | 8 792 | 4 877 | 6 205 | 9 017 | 3 613 | -651 | -1 777 |
| | BG | | 1 427 | 6 826 | 3 052 | -4 067 | -4 101 | -7 038 | -2 896 | -880 |
| | HU | | -632 | 1 602 | -699 | 2 038 | 4 436 | 3 596 | 999 | -1 212 |
| | RS | | -1 116 | -614 | 1 827 | 2 928 | 5 366 | 3 616 | 609 | 3 947 |
| | UA_W | | 695 | 435 | 154 | 471 | 507 | 532 | 93 | 25 |
| | MD | | 543 | 543 | 543 | 4 835 | 2 811 | 2 906 | 544 | -3 658 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net import ratio, %** | | | 1.7% | 15.2% | 8.3% | 10.5% | 15.1% | 5.8% | -1.0% | -2.6% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 46.1% | 47.1% | 52.8% | 48.2% | 42.7% | 52.4% | 63.2% | 74.9% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 33% |
| | Wind | | na | na | na | na | na | na | na | 48% |
| | Solar | | na | na | na | na | na | na | na | 25% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 30.4% | 30.8% | 35.7% | 36.4% | na | na | na | na |
| | Natural gas | | 16.3% | 12.9% | 20.0% | 13.9% | 29.0% | 33.5% | 25.7% | na |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.2% | 78.2% |
| **Natural gas consumption of power generation, TWh** | | | 8.86 | 5.52 | 6.90 | 3.96 | 8.25 | 9.51 | 7.29 | 0 |
| **Security of supply** | Generation adequacy margin | | 65% | 41% | 44% | 32% | 22% | 22% | 22% | 24% |
| | System adequacy margin | | 82% | 71% | 78% | 75% | 69% | 62% | 64% | 75% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 17.8 | 11.2 | 11.6 | 2.4 | 1.7 | 1.9 | 1.5 | 0 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.8% | 75.4% | 74.4% | 94.8% | 96.4% | 95.8% | 96.8% | 100.0% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 16.3 | 14.9 | 16.7 | 13.5 | 12.1 | 16.2 | 3.7 | -30.8 |
| | Clean spark spread, €(2015)/MWh | | -3.2 | -1.1 | -2.8 | -2.9 | -2.5 | 0 | -3.6 | -25.5 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 41.0 | 50.7 | 58.9 | 67.0 | 79.9 | 87.6 | 73.3 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 7.5 | 1.8 | 0.9 | 0.6 | 1.9 | 2.8 | 17.7 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 2.9 | 4.4 | 1.3 | 1.2 | 1.5 | 1.5 | 0 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 46 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 46 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 1 678 | 2 312 | 517 | 660 | 4 357 | 5 260 | 6 362 |
| | Total | | na | 1 725 | 2 312 | 517 | 660 | 4 357 | 5 260 | 6 362 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.78 | 1.95 | 1.93 | 1.89 | 1.98 | 2.04 | 2.04 | 2.04 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A3 | 'DECARBONISATION' SCENARIO

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Installed capacity, MW | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 50 | 450 | 450 | 450 | 400 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 562 | 7 732 | 7 902 | 8 175 | 8 187 | 8 298 |
| | Wind | | 3 026 | 3 436 | 4 595 | 3 921 | 3 306 | 3 731 | 5 481 | 7 980 |
| | Solar | | 1 317 | 1 534 | 1 795 | 2 320 | 2 372 | 3 057 | 4 775 | 6 473 |
| | Other RES | | 129 | 355 | 769 | 1 083 | 1 271 | 1 578 | 1 684 | 1 963 |
| Gross consumption, GWh | | | 54 795 | 57 962 | 58 949 | 58 806 | 60 095 | 62 182 | 65 361 | 69 518 |
| Net electricity generation, GWh | Total | | 53 878 | 51 244 | 59 718 | 59 034 | 60 730 | 65 174 | 69 429 | 72 133 |
| | Coal and lignite | | 13 777 | 9 179 | 9 556 | 1 450 | 0 | 0 | 0 | 0 |
| | Natural gas | | 4 380 | 4 326 | 6 415 | 3 051 | 6 751 | 7 638 | 5 925 | 682 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 776 | 20 776 | 20 501 | 19 179 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 17 881 | 17 881 | 17 881 | 18 145 | 18 258 | 18 624 |
| | Wind | | 6 998 | 7 837 | 10 480 | 8 942 | 7 540 | 8 508 | 12 499 | 18 199 |
| | Solar | | 1 359 | 1 543 | 1 806 | 2 334 | 2 386 | 3 076 | 4 805 | 6 513 |
| | Other RES | | 714 | 1 396 | 3 145 | 4 600 | 5 396 | 7 031 | 7 441 | 8 936 |
| Net import, GWh | Total | | 917 | 6 718 | -769 | -228 | -635 | -2 991 | -4 068 | -2 615 |
| | BG | | 1 427 | 7 276 | 4 713 | 359 | -2 765 | -5 447 | -3 031 | -289 |
| | HU | | -632 | 1 034 | -629 | 1 011 | 3 302 | 3 346 | -361 | 1 759 |
| | RS | | -1 116 | -2 465 | -5 535 | -6 884 | -3 629 | -4 280 | -1 195 | -593 |
| | UA_W | | 695 | 330 | 140 | 448 | 542 | 561 | 132 | 62 |
| | MD | | 543 | 543 | 543 | 4 838 | 1 915 | 2 829 | 387 | -3 554 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net import ratio, % | | | 1.7% | 11.6% | -1.3% | -0.4% | -1.1% | -4.8% | -6.2% | -3.8% |
| RES-E share (RES-E production/gross consumption, %) | | | 46.1% | 47.1% | 56.5% | 57.4% | 55.3% | 59.1% | 65.8% | 75.2% |
| Utilisation rates of RES-E technical potential, % | Hydro | | na | na | na | na | na | na | na | 32% |
| | Wind | | na | na | na | na | na | na | na | 45% |
| | Solar | | na | na | na | na | na | na | na | 38% |
| Utilisation rates of conventional power production, % | Coal and lignite | | 30.4% | 32.4% | 38.4% | 37.6% | na | na | na | na |
| | Natural gas | | 16.3% | 20.5% | 34.9% | 19.9% | 35.8% | 40.5% | 31.4% | 19.5% |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 83.2% | 77.8% |
| Natural gas consumption of power generation, TWh | | | 8.86 | 8.51 | 11.97 | 5.65 | 12.15 | 13.83 | 10.74 | 1.18 |
| Security of supply | Generation adequacy margin | | 65% | 41% | 47% | 40% | 41% | 28% | 24% | 24% |
| | System adequacy margin | | 82% | 71% | 82% | 81% | 91% | 65% | 64% | 70% |
| $CO_2$ emission | Emission, Mt $CO_2$ | | 17.8 | 12.2 | 13.4 | 2.8 | 2.4 | 2.8 | 2.2 | 0.2 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.8% | 73.1% | 70.5% | 93.9% | 94.6% | 93.9% | 95.3% | 99.5% |
| Spreads | Clean dark spread, €(2015)/MWh | | 16.3 | 16.0 | 18.5 | 14.1 | 11.7 | 17.9 | 3.6 | -29.4 |
| | Clean spark spread, €(2015)/MWh | | -3.2 | 0 | -1.1 | -2.3 | -2.9 | 1.8 | -3.7 | -24.0 |
| Price impacts | Electricity wholesale price, €(2015)/MWh | | 34.7 | 42.0 | 52.4 | 59.5 | 66.7 | 81.7 | 87.5 | 74.7 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 7.5 | 2.4 | 3.0 | 2.4 | 1.3 | 0.2 | 0.6 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 3.2 | 5.1 | 1.6 | 1.7 | 2.2 | 2.3 | 0.3 |
| Investment cost, m€/5 year period | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 46.2 | 0 | 0 | 366.3 | 0 | 0 | 0 |
| | Total Fossil | | na | 46.2 | 0 | 0 | 366.3 | 0 | 0 | 0 |
| | Total RES-E | | na | 1 678 | 4 171 | 2 365 | 1 926 | 2 465 | 6 284 | 6 819 |
| | Total | | na | 1 725 | 4 171 | 2 365 | 2 292 | 2 465 | 6 284 | 6 819 |
| Main assumptions | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A4 | SENSITIVITY ANALYSIS – LOW CARBON PRICE

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 50 | 450 | 450 | 450 | 400 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 566 | 7 880 | 8 050 | 8 309 | 8 331 | 8 479 |
| | Wind | | 3 026 | 3 338 | 4 521 | 3 995 | 4 132 | 5 985 | 8 819 | 11 993 |
| | Solar | | 1 317 | 1 534 | 1 879 | 2 461 | 2 794 | 3 569 | 4 956 | 7 105 |
| | Other RES | | 129 | 367 | 965 | 1 381 | 1 637 | 1 694 | 1 995 | 2 207 |
| **Gross consumption, GWh** | | | 54 839 | 58 024 | 59 050 | 58 999 | 60 181 | 62 682 | 65 239 | 69 888 |
| **Net electricity generation, GWh** | Total | | 53 202 | 53 295 | 59 002 | 60 845 | 63 955 | 69 179 | 76 119 | 79 583 |
| | Coal and lignite | | 14 654 | 10 993 | 10 514 | 1 512 | 0 | 0 | 0 | 0 |
| | Natural gas | | 2 827 | 4 740 | 4 058 | 2 632 | 5 431 | 5 490 | 4 506 | 463 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 773 | 20 403 | 18 688 | 15 902 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 17 892 | 18 258 | 18 258 | 18 486 | 18 624 | 18 969 |
| | Wind | | 6 998 | 7 612 | 10 310 | 9 110 | 9 423 | 13 649 | 20 111 | 27 207 |
| | Solar | | 1 359 | 1 543 | 1 891 | 2 476 | 2 811 | 3 591 | 4 986 | 7 026 |
| | Other RES | | 714 | 1 443 | 3 901 | 6 081 | 7 259 | 7 560 | 9 204 | 10 016 |
| **Net import, GWh** | Total | | 1 637 | 4 730 | 49 | -1 846 | -3 774 | -6 498 | -10 880 | -9 695 |
| | BG | | 1 534 | 5 510 | 3 966 | -965 | -1 722 | -5 051 | -1 106 | -1 160 |
| | HU | | -60 | 1 481 | 698 | 268 | 366 | -684 | -5 972 | -5 660 |
| | RS | | -1 056 | -3 334 | -5 353 | -5 267 | -5 157 | -3 125 | -703 | 1 214 |
| | UA_W | | 676 | 530 | 196 | 129 | 290 | 201 | 149 | -88 |
| | MD | | 543 | 543 | 543 | 3 989 | 2 450 | 2 161 | -3 249 | -4 001 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net import ratio, %** | | | 3.0% | 8.2% | 0.1% | -3.1% | -6.3% | -10.4% | -16.7% | -13.9% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 46.1% | 46.7% | 57.6% | 60.9% | 62.7% | 69.1% | 81.1% | 90.5% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 33.0% |
| | Wind | | na | na | na | na | na | na | na | 66.9% |
| | Solar | | na | na | na | na | na | na | na | 42.2% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 32.4% | 38.8% | 42.3% | 39.2% | na | na | na | na |
| | Natural gas | | 10.6% | 22.5% | 22.1% | 17.1% | 28.8% | 29.1% | 23.9% | 13.2% |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 82.8% | 75.8% | 64.5% |
| **Natural gas consumption of power generation, TWh** | | | 6.0 | 9.3 | 7.6 | 4.9 | 9.9 | 10.0 | 8.2 | 0.8 |
| **Security of supply** | Generation adequacy margin | | 65% | 41% | 49% | 44% | 47% | 48% | 54% | 38% |
| | System adequacy margin | | 82% | 71% | 84% | 85% | 98% | 86% | 97% | 90% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 18.2 | 14.3 | 13.5 | 2.7 | 2.0 | 2.0 | 1.7 | 0.2 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.0% | 68.5% | 70.2% | 94.1% | 95.6% | 95.6% | 96.4% | 99.6% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 13.4 | 12.1 | 12.5 | 3.2 | -1.4 | 7.8 | -15.0 | -54.1 |
| | Clean spark spread, €(2015)/MWh | | -6.0 | -3.9 | -7.1 | -13.1 | -16.0 | -8.3 | -22.3 | -48.7 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 31.8 | 38.2 | 46.5 | 48.7 | 53.5 | 71.6 | 69.0 | 50.0 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 8.2 | 8.4 | 9.4 | 11.4 | 11.8 | 14.1 | 28.6 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 3.7 | 5.2 | 1.5 | 1.4 | 1.6 | 1.7 | 0.2 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 46 | 0 | 0 | 366 | 0 | 0 | 0 |
| | Total Fossil | | na | 46 | 0 | 0 | 366 | 0 | 0 | 0 |
| | Total RES-E | | na | 1 589 | 4 312 | 3 056 | 3 135 | 4 093 | 6 587 | 7 506 |
| | Total | | na | 1 635 | 4 312 | 3 056 | 3 501 | 4 093 | 6 587 | 7 506 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.78 | 1.95 | 1.93 | 1.89 | 1.98 | 2.04 | 2.04 | 2.04 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 4.30 | 7.50 | 11.25 | 16.75 | 21.00 | 25.00 | 34.50 | 44.00 |

## TABLE A5 | SENSITIVITY ANALYSIS – LOW DEMAND

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 50 | 50 | 50 | 50 | 0 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 562 | 7 732 | 7 902 | 8 071 | 8 187 | 8 153 |
| | Wind | | 3 026 | 3 436 | 4 595 | 3 385 | 2 753 | 3 151 | 4 942 | 6 067 |
| | Solar | | 1 317 | 1 534 | 1 795 | 1 956 | 1 850 | 2 046 | 3 308 | 4 940 |
| | Other RES | | 129 | 355 | 733 | 930 | 1 022 | 1 135 | 1 514 | 1 643 |
| **Gross consumption, GWh** | | | 54 795 | 57 393 | 57 649 | 56 784 | 57 504 | 58 366 | 60 751 | 64 500 |
| **Net electricity generation, GWh** | Total | | 53 880 | 50 719 | 59 433 | 57 244 | 57 465 | 59 845 | 63 957 | 63 856 |
| | Coal and lignite | | 13 778 | 9 045 | 9 553 | 1 537 | 0 | 0 | 0 | 0 |
| | Natural gas | | 4 381 | 3 936 | 6 330 | 3 474 | 6 305 | 7 073 | 3 862 | 0 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 776 | 20 776 | 20 457 | 19 513 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 17 881 | 17 881 | 17 881 | 17 881 | 18 258 | 18 258 |
| | Wind | | 6 998 | 7 837 | 10 479 | 7 721 | 6 277 | 7 185 | 11 270 | 13 835 |
| | Solar | | 1 359 | 1 543 | 1 806 | 1 968 | 1 861 | 2 059 | 3 328 | 4 971 |
| | Other RES | | 714 | 1 396 | 2 948 | 3 887 | 4 366 | 4 872 | 6 782 | 7 280 |
| **Net import, GWh** | Total | | 915 | 6 673 | -1 784 | -459 | 39 | -1 479 | -3 207 | 644 |
| | BG | | 1 356 | 7 029 | 5 155 | 1 137 | -2 054 | -6 073 | -2 817 | 71 |
| | HU | | -622 | 1 216 | -1 394 | 783 | 4 003 | 4 580 | 2 081 | 2 576 |
| | RS | | -1 069 | -2 524 | -6 142 | -7 622 | -6 264 | -4 392 | -2 628 | 1 107 |
| | UA_W | | 707 | 409 | 54 | 420 | 493 | 612 | 189 | 239 |
| | MD | | 543 | 543 | 543 | 4 823 | 3 861 | 3 793 | -31 | -3 350 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net import ratio, %** | | | 1.7% | 11.6% | -3.1% | -0.8% | 0.1% | -2.5% | -5.3% | 1.0% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 46.1% | 47.6% | 57.4% | 55.4% | 52.8% | 54.8% | 65.2% | 68.7% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 31.6% |
| | Wind | | na | na | na | na | na | na | na | 33.8% |
| | Solar | | na | na | na | na | na | na | na | 29.3% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 30.5% | 31.9% | 38.4% | 39.9% | na | na | na | na |
| | Natural gas | | 16.4% | 18.7% | 34.4% | 22.6% | 41.1% | 46.1% | 25.2% | na |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 83.0% | 79.2% |
| **Natural gas consumption of power generation, TWh** | | | 8.9 | 7.8 | 11.8 | 6.4 | 11.7 | 13.1 | 7.1 | 0 |
| **Security of supply** | Generation adequacy margin | | 65% | 42% | 50% | 41% | 43% | 30% | 29% | 13% |
| | System adequacy margin | | 82% | 73% | 85% | 83% | 93% | 71% | 74% | 60% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 17.8 | 11.9 | 13.4 | 3.0 | 2.3 | 2.6 | 1.4 | 0 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.8% | 73.7% | 70.6% | 93.4% | 94.8% | 94.2% | 96.8% | 100.0% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 16.3 | 15.6 | 18.4 | 14.6 | 15.3 | 25.2 | 0.2 | -28.7 |
| | Clean spark spread, €(2015)/MWh | | -3.2 | -0.3 | -1.2 | -1.8 | 0.7 | 9.1 | -7.1 | -23.4 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 41.7 | 52.3 | 60.0 | 70.2 | 89.0 | 84.1 | 75.4 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 7.5 | 3.6 | 2.1 | 1.6 | 0.3 | 0 | 0 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 3.1 | 5.2 | 1.8 | 1.7 | 2.3 | 1.6 | 0 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 46.2 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 46 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 1 678 | 3 612 | 1 109 | 1 574 | 1 681 | 5 341 | 3 383 |
| | Total | | na | 1 725 | 3 612 | 1 109 | 1 574 | 1 681 | 5 341 | 3 383 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A6 | SENSITIVITY ANALYSIS – HIGH DEMAND

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| Installed capacity, MW | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 50 | 450 | 450 | 450 | 400 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 566 | 7 880 | 8 050 | 8 347 | 8 331 | 8 479 |
| | Wind | | 3 026 | 3 436 | 4 620 | 4 093 | 4 056 | 6 006 | 8 822 | 11 996 |
| | Solar | | 1 317 | 1 534 | 1 879 | 2 461 | 2 879 | 3 799 | 5 359 | 7 169 |
| | Other RES | | 129 | 355 | 947 | 1 395 | 1 632 | 1 659 | 1 977 | 2 201 |
| Gross consumption, GWh | | | 54 795 | 58 534 | 60 272 | 60 887 | 62 821 | 66 302 | 69 778 | 75 512 |
| Net electricity generation, GWh | Total | | 53 880 | 51 792 | 61 100 | 61 540 | 64 834 | 71 417 | 78 416 | 82 211 |
| | Coal and lignite | | 13 778 | 9 298 | 9 639 | 1 356 | 0 | 0 | 0 | 0 |
| | Natural gas | | 4 381 | 4 755 | 6 876 | 3 205 | 6 416 | 7 278 | 5 656 | 729 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 776 | 20 698 | 19 529 | 17 948 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 17 892 | 18 258 | 18 258 | 18 580 | 18 624 | 19 043 |
| | Wind | | 6 998 | 7 837 | 10 536 | 9 335 | 9 249 | 13 697 | 20 118 | 27 299 |
| | Solar | | 1 359 | 1 543 | 1 891 | 2 476 | 2 896 | 3 822 | 5 392 | 7 168 |
| | Other RES | | 714 | 1 396 | 3 830 | 6 135 | 7 238 | 7 342 | 9 097 | 10 025 |
| Net import, GWh | Total | | 915 | 6 742 | -828 | -653 | -2 013 | -5 115 | -8 639 | -6 699 |
| | BG | | 1 374 | 7 313 | 4 654 | -231 | -3 054 | -4 755 | -2 762 | -1 352 |
| | HU | | -342 | 875 | -1 560 | 883 | 3 027 | 1 600 | -335 | -1 075 |
| | RS | | -1 383 | -2 501 | -4 655 | -6 601 | -3 206 | -4 209 | -4 672 | -1 154 |
| | UA_W | | 723 | 511 | 189 | 442 | 445 | 423 | 183 | 125 |
| | MD | | 543 | 543 | 543 | 4 854 | 775 | 1 826 | -1 053 | -3 243 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Net import ratio, % | | | 1.7% | 11.5% | -1.4% | -1.1% | -3.2% | -7.7% | -12.4% | -8.9% |
| RES-E share (RES-E production/gross consumption, %) | | | 46.1% | 46.6% | 56.7% | 59.5% | 59.9% | 65.5% | 76.3% | 84.1% |
| Utilisation rates of RES-E technical potential, % | Hydro | | na | na | na | na | na | na | na | 33.0% |
| | Wind | | na | na | na | na | na | na | na | 66.9% |
| | Solar | | na | na | na | na | na | na | na | 42.6% |
| Utilisation rates of conventional power production, % | Coal and lignite | | 30.5% | 32.8% | 38.7% | 35.2% | na | na | na | na |
| | Natural gas | | 16.4% | 22.6% | 37.4% | 20.9% | 34.0% | 38.6% | 30.0% | 20.8% |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.0% | 79.3% | 72.8% |
| Natural gas consumption of power generation, TWh | | | 8.9 | 9.3 | 12.8 | 5.9 | 11.6 | 13.2 | 10.3 | 1.3 |
| Security of supply | Generation adequacy margin | | 65% | 40% | 46% | 40% | 42% | 41% | 46% | 31% |
| | System adequacy margin | | 82% | 70% | 80% | 80% | 90% | 78% | 86% | 80% |
| $CO_2$ emission | Emission, Mt $CO_2$ | | 17.8 | 12.5 | 13.6 | 2.7 | 2.3 | 2.6 | 2.1 | 0.3 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.8% | 72.5% | 70.0% | 94.0% | 94.9% | 94.2% | 95.5% | 99.4% |
| Spreads | Clean dark spread, €(2015)/MWh | | 25.4 | 32.2 | 42.6 | 49.6 | 56.2 | 69.4 | 71.9 | 61.5 |
| | Clean spark spread, €(2015)/MWh | | 0.3 | 6.3 | 8.2 | 11.1 | 13.8 | 20.2 | 19.1 | 8.7 |
| Price impacts | Electricity wholesale price, €(2015)/MWh | | 34.7 | 42.4 | 52.7 | 59.4 | 66.5 | 80.0 | 82.6 | 72.2 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 7.5 | 8.3 | 7.5 | 7.6 | 6.9 | 6.7 | 16.7 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 3.2 | 5.1 | 1.5 | 1.6 | 2.0 | 2.0 | 0.3 |
| Investment cost, m€/5 year period | Coal and lignite | | na | 46.2 | 0 | 0 | 366.3 | 0 | 0 | 0 |
| | Natural gas | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 46 | 0 | 0 | 366 | 0 | 0 | 0 |
| | Total RES-E | | na | 1 678 | 4 294 | 3 100 | 2 978 | 4 388 | 6 632 | 7 297 |
| | Total | | na | 1 725 | 4 294 | 3 100 | 3 345 | 4 388 | 6 632 | 7 297 |
| Main assumptions | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A7 | SENSITIVITY ANALYSIS – LOW RENEWABLE POTENTIAL

| | | | 2016 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Installed capacity, MW** | Coal, lignite | Existing | 5 165 | 3 235 | 2 840 | 440 | 0 | 0 | 0 | 0 |
| | | New | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | Existing | 3 058 | 2 353 | 2 048 | 1 703 | 1 703 | 1 703 | 1 703 | 0 |
| | | New | 0 | 50 | 50 | 50 | 450 | 450 | 450 | 400 |
| | Nuclear | Existing | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 | 1 413 |
| | | New | 0 | 0 | 0 | 1 400 | 1 400 | 1 400 | 1 400 | 1 400 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 6 700 | 6 859 | 7 531 | 7 701 | 7 871 | 8 041 | 8 056 | 8 182 |
| | Wind | | 3 026 | 3 177 | 4 043 | 3 230 | 2 530 | 3 305 | 4 832 | 6 296 |
| | Solar | | 1 317 | 1 634 | 2 101 | 3 054 | 4 103 | 5 972 | 8 499 | 10 974 |
| | Other RES | | 129 | 331 | 908 | 1 222 | 1 516 | 1 671 | 2 001 | 2 705 |
| **Gross consumption, GWh** | | | 54 795 | 57 961 | 58 948 | 58 824 | 60 410 | 62 490 | 65 596 | 69 370 |
| **Net electricity generation, GWh** | Total | | 53 834 | 50 777 | 59 388 | 58 771 | 61 974 | 67 445 | 72 862 | 75 412 |
| | Coal and lignite | | 13 784 | 9 210 | 9 584 | 1 460 | 0 | 0 | 0 | 0 |
| | Natural gas | | 4 387 | 4 411 | 6 550 | 3 158 | 6 859 | 7 851 | 6 089 | 751 |
| | Nuclear | | 10 436 | 10 436 | 10 436 | 20 776 | 20 776 | 20 774 | 20 050 | 18 946 |
| | HFO/LFO | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | | 16 214 | 16 527 | 17 803 | 17 803 | 17 803 | 17 803 | 17 927 | 18 331 |
| | Wind | | 6 945 | 7 245 | 9 220 | 7 365 | 5 769 | 7 536 | 11 019 | 14 357 |
| | Solar | | 1 375 | 1 644 | 2 114 | 3 072 | 4 128 | 6 008 | 8 551 | 11 042 |
| | Other RES | | 694 | 1 303 | 3 681 | 5 136 | 6 639 | 7 471 | 9 226 | 11 986 |
| **Net import, GWh** | Total | | 961 | 7 184 | -439 | 53 | -1 564 | -4 954 | -7 265 | -6 042 |
| | BG | | 1 400 | 7 930 | 4 809 | 893 | -1 443 | -3 864 | -2 693 | -1 758 |
| | HU | | -531 | 698 | -1 080 | 738 | 3 550 | 1 551 | -1 251 | -1 318 |
| | RS | | -1 127 | -2 375 | -4 895 | -6 846 | -6 307 | -5 956 | -4 057 | -13 |
| | UA_W | | 676 | 387 | 183 | 427 | 485 | 453 | 292 | 93 |
| | MD | | 543 | 543 | 543 | 4 839 | 2 151 | 2 861 | 443 | -3 046 |
| | UA_E | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | TR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net import ratio, %** | | | 1.8% | 12.4% | -0.7% | 0.1% | -2.6% | -7.9% | -11.1% | -8.7% |
| **RES-E share (RES-E production/gross consumption, %)** | | | 46.0% | 46.1% | 55.7% | 56.7% | 56.8% | 62.1% | 71.2% | 80.3% |
| **Utilisation rates of RES-E technical potential, %** | Hydro | | na | na | na | na | na | na | na | 31.7% |
| | Wind | | na | na | na | na | na | na | na | 35.1% |
| | Solar | | na | na | na | na | na | na | na | 65.1% |
| **Utilisation rates of conventional power production, %** | Coal and lignite | | 30.5% | 32.5% | 38.5% | 37.9% | na | na | na | na |
| | Natural gas | | 16.4% | 21.0% | 35.6% | 20.6% | 36.4% | 41.6% | 32.3% | 21.4% |
| | Nuclear | | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 84.3% | 81.4% | 76.9% |
| **Natural gas consumption of power generation, TWh** | | | 8.9 | 8.7 | 12.2 | 5.8 | 12.4 | 14.2 | 11.0 | 1.3 |
| **Security of supply** | Generation adequacy margin | | 65% | 41% | 47% | 40% | 41% | 26% | 24% | 12% |
| | System adequacy margin | | 82% | 70% | 82% | 82% | 86% | 62% | 62% | 52% |
| **$CO_2$ emission** | Emission, Mt $CO_2$ | | 17.8 | 12.3 | 13.5 | 2.8 | 2.5 | 2.9 | 2.2 | 0.3 |
| | $CO_2$ emission reduction compared to 1990, % | | 60.8% | 72.9% | 70.4% | 93.8% | 94.5% | 93.7% | 95.1% | 99.4% |
| **Spreads** | Clean dark spread, €(2015)/MWh | | 25.4 | 32.0 | 42.4 | 49.8 | 56.4 | 71.1 | 74.9 | 64.2 |
| | Clean spark spread, €(2015)/MWh | | 0.3 | 6.1 | 8.0 | 11.3 | 14.1 | 21.9 | 22.1 | 11.4 |
| **Price impacts** | Electricity wholesale price, €(2015)/MWh | | 34.7 | 42.1 | 52.5 | 59.6 | 66.8 | 81.7 | 85.6 | 74.8 |
| | Total RES-E support/gross consumption, €(2015)/MWh, five year average | | na | 6.5 | 7.2 | 5.0 | 5.5 | 5.8 | 7.8 | 65.7 |
| | Revenue from $CO_2$ auction/gross consumption, €(2015)/MWh | | 2.8 | 3.2 | 5.1 | 1.6 | 1.7 | 2.3 | 2.3 | 0.3 |
| **Investment cost, m€/5 year period** | Coal and lignite | | na | 46.2 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Natural gas | | na | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total Fossil | | na | 46 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Total RES-E | | na | 1 345 | 3 936 | 2 226 | 2 917 | 3 497 | 5 580 | 6 340 |
| | Total | | na | 1 391 | 3 936 | 2 226 | 2 917 | 3 497 | 5 580 | 6 340 |
| **Main assumptions** | Coal price, €(2015)/GJ | | 1.8 | 2.0 | 1.9 | 1.9 | 2.0 | 2.0 | 2.0 | 2.0 |
| | Lignite price, €(2015)/GJ | | 0.98 | 1.07 | 1.06 | 1.04 | 1.09 | 1.12 | 1.12 | 1.12 |
| | Natural gas price, €(2015)/MWh | | 17.20 | 18.02 | 22.25 | 24.17 | 26.33 | 29.92 | 31.75 | 31.71 |
| | $CO_2$ price, €(2015)/t | | 8.60 | 15.00 | 22.50 | 33.50 | 42.00 | 50.00 | 69.00 | 88.00 |

## TABLE A8 | BREAK DOWN OF CUMULATIVE CAPITAL EXPENDITURE BY RES TECHNOLOGY (m€)

| Capital expenditures | No target 2016-2050 | Delayed 2016-2050 | Decarbon 2016-2050 |
|---|---|---|---|
| Biogas | 573 | 884 | 1 823 |
| Solid biomass | 1 160 | 1 415 | 3 580 |
| Biowaste | 1 010 | 1 010 | 844 |
| Geothermal ele. | 741 | 1 309 | 757 |
| Hydro large-scale | 857 | 1 426 | 951 |
| Hydro small-scale | 208 | 574 | 1 217 |
| Central PV | 449 | 959 | 1 392 |
| Decentralised PV | 792 | 2 158 | 3 547 |
| CSP | – | – | – |
| Wind onshore | 6 302 | 11 409 | 11 598 |
| Wind offshore | 0 | 0 | 0 |
| RES-E total | 12 093 | 21 147 | 25 708 |

## TABLE A9 | DEVELOPMENT OF SUPPORT EXPENDITURES (FOR RES TOTAL) OVER TIME (5-YEAR TIME PERIODS)

| Support expenditures in M€ | 2016-2020 | 2021-2025 | 2026-2030 | 2031-2035 | 2036-2040 | 2041-2045 | 2046-2050 | Total |
|---|---|---|---|---|---|---|---|---|
| **No target** | **2 289** | **1 834** | **838** | **470** | **576** | **384** | **119** | **6 510** |
| Central PV | 315 | 369 | 171 | 94 | 149 | 66 | – | 1 165 |
| Decentralised PV | 236 | 285 | 147 | 80 | 126 | 57 | – | 931 |
| Wind onshore | 901 | 734 | 243 | 118 | 54 | – | – | 2 050 |
| **Delayed** | **2 318** | **572** | **277** | **187** | **631** | **967** | **6 576** | **11 529** |
| Central PV | 320 | 20 | 9 | 5 | 18 | 39 | 288 | 698 |
| Decentralised PV | 240 | 20 | 9 | 8 | 38 | 74 | 568 | 958 |
| Wind onshore | 910 | 177 | 69 | 49 | 292 | 456 | 3 166 | 5 119 |
| **Decarbon** | **2 301** | **780** | **955** | **778** | **449** | **71** | **222** | **5 556** |
| Central PV | 317 | 52 | 63 | 54 | 49 | 17 | 122 | 674 |
| Decentralised PV | 238 | 42 | 59 | 56 | 22 | 1 | 21 | 438 |
| Wind onshore | 905 | 625 | 780 | 655 | 378 | 52 | 80 | 3 474 |

# Annex 2 | Assumptions

## Assumed technology investment cost trajectories: RES and fossil

**TABLE A10 | ASSUMED SPECIFIC COST TRAJECTORIES FOR RES TECHNOLOGIES (2016 €/kW)**

| Technology | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Biogas (low cost options: landfill and sewage gas) | 1 663 | 1 608 | 1 555 | 1 504 | 1 454 | 1 406 | 1 360 | 1 315 |
| Biogas (high cost options: agricultural digestion in small-scale CHP plants) | 5 602 | 5 378 | 5 163 | 4 956 | 4 758 | 4 568 | 4 385 | 4 210 |
| Solid biomass (low cost options: cofiring) | 619 | 597 | 574 | 553 | 533 | 513 | 494 | 476 |
| Solid biomass (medium cost options: large-scale CHP) | 2 505 | 2 410 | 2 318 | 2 230 | 2 145 | 2 064 | 1 985 | 1 910 |
| Solid biomass (high cost options: small/medium-scale CHP) | 4 067 | 3 912 | 3 764 | 3 621 | 3 483 | 3 351 | 3 223 | 3 101 |
| Biowaste | 6 840 | 6 573 | 6 317 | 6 070 | 5 833 | 5 606 | 5 387 | 5 177 |
| Geothermal electricity (average cost trend for SEERMAP region – i.e. mix of high-temperature (default technology concepts) and medium-temperature resources (novel enhanced systems)) | 2 570 | 3 273 | 2 410 | 2 963 | 3 482 | 3 269 | 3 038 | 3 167 |
| Hydro large-scale* | 1 304 | 1 333 | 1 464 | 1 396 | 1 618 | 1 667 | 1 608 | 1 765 |
| Hydro small-scale* | 1 321 | 1 338 | 1 402 | 1 763 | 1 919 | 1 956 | 1 944 | 1 994 |
| Photovoltaics* | 1 309 | 1 015 | 908 | 824 | 764 | 693 | 640 | 596 |
| Wind onshore* | 1 491 | 1 395 | 1 311 | 1 271 | 1 246 | 1 199 | 1 150 | 1 125 |
| Wind offshore* | 3 797 | 2 693 | 2 636 | 2 521 | 2 407 | 2 293 | 2 416 | 2 346 |

Source: Green-X database

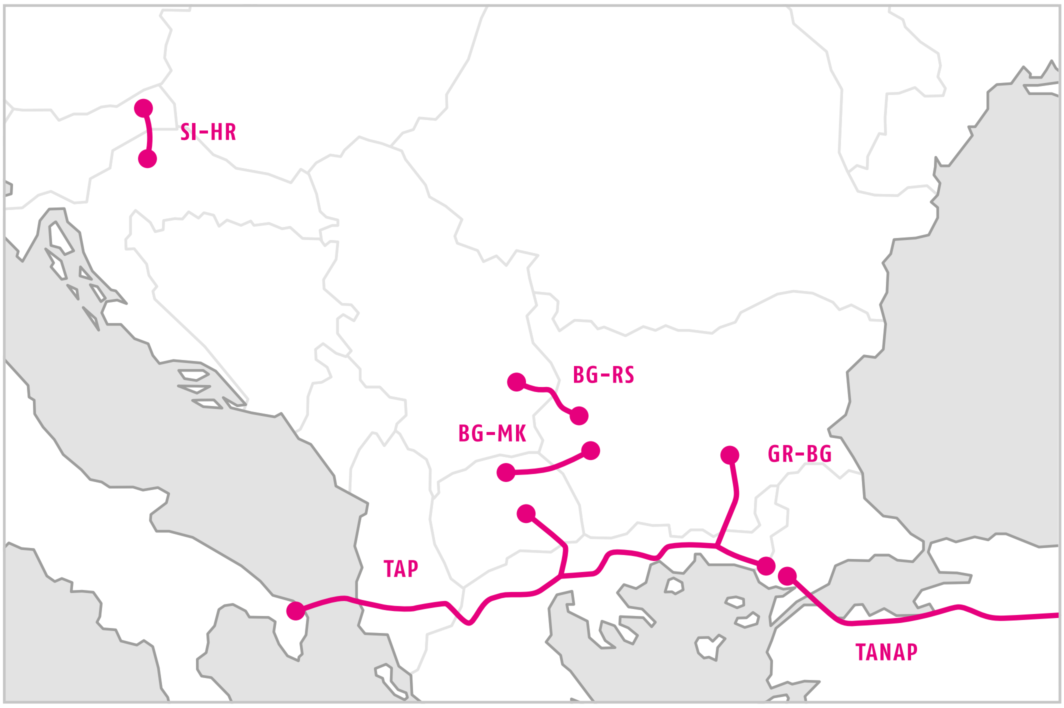
## Infrastructure (table for the whole region)

**TABLE A11 | NEW GAS INFRASTRUCTURE IN THE REGION**

| Pipeline | From | To | Capacity, GWh/day | Date of commissioning |
|---|---|---|---|---|
| BG-RS | BG | RS | 51 | 2018 |
| RS-BG | RS | BG | 51 | 2018 |
| TR-GR2_TAP | TR | GR | 350 | 2019 |
| GR-MK_TAP | GR | MK | 25 | 2019 |
| AZ-TR_TANAP | AZ | TR | 490 | 2018 |
| GR-BG | GR | BG | 90 | 2018 |
| GR-BG | GR | BG | 151 | 2021 |
| GR-IT_TAP | GR | IT | 334 | 2019 |
| SI-HR2 | SI | HR | 162 | 2019 |
| HR-SI | HR | SI | 162 | 2019 |
| GR-AL | GR | AL | 40 | 2019 |
| BG-MK | BG | MK | 27 | 2020 |
| HR-LNG | | HR | 108 | 2020 |
| BG-RO | BG | RO | 14 | 2016 |
| RO-BG | RO | BG | 14 | 2016 |
| GR-LNG expansion | | GR | 81 | 2017 |
| RO-HU (BRUA) | RO | HU | 126 | 2020 |
| HU-RO (BRUA) | HU | RO | 77 | 2020 |

Source: ENTSO-G TYNDP

**FIGURE A1**
NEW GAS INFRASTRUCTURE INVESTMENT ASSUMED TO TAKE PLACE IN ALL SCENARIOS




Source: ENTSO-G TYNDP 2017

**TABLE A12 | CROSS BORDER TRANSMISSION NETWORK CAPACITIES**

| From | To | Year of commissioning | Capacity, MW O → D | Capacity, MW D → O |
|---|---|---|---|---|
| ME | IT | 2019 | 500 | 500 |
| ME | IT | 2023 | 700 | 700 |
| BA_FED | HR | 2022 | 650 | 950 |
| BG | RO | 2020 | 1 000 | 1 200 |
| GR | BG | 2021 | 0 | 650 |
| RS | RO | 2023 | 500 | 950 |
| ME | RS | 2025 | 400 | 600 |
| AL | RS | 2016 | 700 | 700 |
| AL | MK | 2020 | 250 | 250 |
| RS | ME | 2025 | 500 | 500 |
| RS | BA_SRP | 2025 | 600 | 500 |
| BA_SRP | HR | 2030 | 350 | 250 |
| HR | RS | 2030 | 750 | 300 |
| HU | RO | 2035 | 200 | 800 |
| RS | RO | 2035 | 500 | 550 |
| RS | BG | 2034 | 50 | 200 |
| RS | RO | 2035 | 0 | 100 |
| RS | BG | 2034 | 400 | 1 500 |
| GR | BG | 2030 | 250 | 450 |
| KO* | MK | 2030 | 1 100 | 1 200 |
| KO* | AL | 2035 | 1 400 | 1 300 |
| MD | RO | 2030 | 500 | 500 |
| BG | GR | 2045 | 1 000 | 1 000 |
| HU | RO | 2043 | 1 000 | 1 000 |
| HU | RO | 2047 | 1 000 | 1 000 |
| IT | ME | 2045 | 2 000 | 2 000 |
| IT | GR | 2037 | 2 000 | 2 000 |
| IT | GR | 2045 | 3 000 | 3 000 |

Source: ENTSO-E TYNDP 2017

## Generation units and their inclusion in the core scenarios

TABLE A13 | LIST OF GENERATION UNITS INCLUDED EXOGENOUSLY IN THE MODEL IN THE CORE SCENARIOS

| Unit name | Installed capacity [MW] | Expected year of commissioning | Expected year of decommissioning | Fuel type | Type | CCS | No target | Delay | De-carbon |
|---|---|---|---|---|---|---|---|---|---|
| TPP Iernut 1 (Mures) | 100.0 | 1963 | 2020 | natural gas | OCGT | no | yes | yes | yes |
| CHP Paroseni I. | 150.0 | 2007 | 2027 | coal | thermal | no | yes | yes | yes |
| Bucaresti Sud CHP 1 | 50.0 | 1965 | 2005 | natural gas | OCGT | no | yes | yes | yes |
| DROBETA 1 | 60.0 | 1985 | 2015 | coal | thermal | no | yes | yes | yes |
| DROBETA 4 | 60.0 | 1985 | 2024 | coal | thermal | no | yes | yes | yes |
| DROBETA 5 | 60.0 | 1985 | 2015 | coal | thermal | no | yes | yes | yes |
| DROBETA 6 | 60.0 | 1985 | 2015 | coal | thermal | no | yes | yes | yes |
| CHP Orodea I. A-B | 50.0 | 1966 | 2015 | coal | thermal | no | yes | yes | yes |
| Bucaresti Sud CHP 2 | 50.0 | 1966 | 2006 | natural gas | OCGT | no | yes | yes | yes |
| TPP Iernut 2 (Mures) | 100.0 | 1966 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| TPP Iernut 3 (Mures) | 100.0 | 1966 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| TPP Iernut 4 (Mures) | 100.0 | 1966 | 2020 | natural gas | OCGT | no | yes | yes | yes |
| TPP Iernut 5 (Mures) | 200.0 | 1966 | 2020 | natural gas | OCGT | no | yes | yes | yes |
| CHP Orodea I. C | 50.0 | 1967 | 2015 | coal | thermal | no | yes | yes | yes |
| TPP Iernut 6 (Mures) | 200.0 | 1967 | 2020 | natural gas | OCGT | no | yes | yes | yes |
| Bucaresti Sud CHP 3-4 | 195.0 | 1967 | 2007 | natural gas | OCGT | no | yes | yes | yes |
| TPP Isalnita 7 | 315.0 | 1967 | 2027 | coal | thermal | no | yes | yes | yes |
| TPP Isalnita 8 | 315.0 | 1968 | 2028 | coal | thermal | no | yes | yes | yes |
| TPP Mintia 2 | 210.0 | 1969 | 2016 | coal | thermal | no | yes | yes | yes |
| CHP Galati 3 | 105.0 | 1969 | 2020 | natural gas | OCGT | no | yes | yes | yes |
| TPP Borzesti Cd | 210.0 | 1969 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| Palas Constanta CHPP 1 | 50.0 | 1970 | 2010 | natural gas | OCGT | no | yes | yes | yes |
| Palas Constanta CHPP 2 | 50.0 | 1971 | 2011 | natural gas | OCGT | no | yes | yes | yes |
| CHP Orodea I. D-E | 50.0 | 1971 | 2015 | coal | thermal | no | yes | yes | yes |
| TPP Mintia 3 | 235.0 | 1971 | 2023 | coal | thermal | no | yes | yes | yes |
| TPP Braila 2A | 227.0 | 1973 | 2013 | natural gas | OCGT | no | yes | yes | yes |
| TPP Brazi | 235.0 | 1973 | 2013 | natural gas | OCGT | no | yes | yes | yes |
| TPP Mintia 4 | 210.0 | 1973 | 2016 | coal | thermal | no | yes | yes | yes |
| TPP Braila 2B | 210.0 | 1974 | 2014 | natural gas | OCGT | no | yes | yes | yes |
| CHP Galati, 4 | 60.0 | 1975 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| TPP Mintia 5 | 210.0 | 1975 | 2016 | coal | thermal | no | yes | yes | yes |
| Bucaresti Vest CHP 1-2 | 250.0 | 1975 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| Bucaresti Sud CHP 5 | 125.0 | 1975 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| Bucaresti Sud CHP 6 | 125.0 | 1975 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| TPP Rovinari III. | 330.0 | 1976 | 2026 | lignite | thermal | no | yes | yes | yes |
| TPP Mintia 6 | 210.0 | 1977 | 2016 | coal | thermal | no | yes | yes | yes |
| TPP Rovinari IV. | 330.0 | 1977 | 2027 | lignite | thermal | no | yes | yes | yes |
| TPP Rovinari V. | 330.0 | 1978 | 2018 | lignite | thermal | no | yes | yes | yes |
| TPP Rovinari VI. | 330.0 | 1979 | 2019 | lignite | thermal | no | yes | yes | yes |
| TPP Turceni 1 | 330.0 | 1980 | 2015 | lignite | thermal | no | yes | yes | yes |
| TPP Turceni 3 | 330.0 | 1980 | 2028 | lignite | thermal | no | yes | yes | yes |
| TPP Turceni 4 | 330.0 | 1981 | 2030 | lignite | thermal | no | yes | yes | yes |
| CHP Galati, 5 | 105.0 | 1983 | 2015 | natural gas | OCGT | no | yes | yes | yes |
| TPP Turceni 5 | 330.0 | 1983 | 2019 | lignite | thermal | no | yes | yes | yes |
| CHP Galati, 6 | 105.0 | 1984 | 2023 | natural gas | OCGT | no | yes | yes | yes |
| TPP Turceni 6 | 330.0 | 1985 | 2015 | lignite | thermal | no | yes | yes | yes |
| CHP Iasi II. A | 110.0 | 1986 | 2032 | coal | thermal | no | yes | yes | yes |
| CHP Govora 3. | 50.0 | 1986 | 2023 | coal | thermal | no | yes | yes | yes |
| CHP Suceava A | 60.0 | 1987 | 2014 | coal | thermal | no | yes | yes | yes |
| CHP Govora 4 | 50.0 | 1987 | 2023 | coal | thermal | no | yes | yes | yes |
| TPP Craiova I. | 150.0 | 1987 | 2030 | lignite | thermal | no | yes | yes | yes |
| TPP Turceni 7 | 330.0 | 1987 | 2031 | lignite | thermal | no | yes | yes | yes |
| TPP Craiova II. | 150.0 | 1988 | 2030 | lignite | thermal | no | yes | yes | yes |
| CHP Suceava B | 60.0 | 1989 | 2014 | coal | thermal | no | yes | yes | yes |
| NPP Cernavoda I. | 706.5 | 1996 | 2056 | nuclear | nuclear | no | yes | yes | yes |
| Bacau | 60.0 | 1997 | 2014 | lignite | thermal | no | yes | yes | yes |
| NPP Cernavoda II. | 706.5 | 2007 | 2067 | nuclear | nuclear | no | yes | yes | yes |
| Cet Vest 3 | 195.0 | 2009 | 2050 | natural gas | CCGT | no | yes | yes | yes |
| Arad | 60.0 | 1993 | 2027 | natural gas | OCGT | no | yes | yes | yes |
| Brazi | 894.0 | 2012 | 2050 | natural gas | CCGT | no | yes | yes | yes |
| Grazovesti | 100.0 | 1964 | 2023 | natural gas | CCGT | no | yes | yes | yes |
| 92 small new TPPs | 614.0 | 2010 | 2050 | natural gas | CCGT | no | yes | yes | yes |
| TPP Brazi 5-6 | 210.0 | 1978 | 2028 | natural gas | OCGT | no | yes | yes | yes |
| CET Progresu | 100.0 | 1986 | 2023 | natural gas | OCGT | no | yes | yes | yes |
| CHP Govora 5-6 | 100.0 | 1986 | 2017 | lignite | thermal | no | yes | yes | yes |
| 7 small old TPPs | 75.0 | 1980 | 2030 | natural gas | thermal | no | yes | yes | yes |
| CHP Oradea | 50.0 | 2016 | 2050 | natural gas | CCGT | no | yes | yes | yes |
| Nuclear | 1400.0 | 2028 | 2068 | nuclear | nuclear | no | yes | yes | yes |

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