SEERMAP

South East Europe Electricity Roadmap

SOUTH EAST EUROPE ELECTRICITY ROADMAP

Country report

Bulgaria

SEERMAP: South East Europe Electricity Roadmap
Country report: Bulgaria 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 **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.

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.

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.

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.

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, with a mix of EU member states, candidate and potential candidate countries. Despite this diversity, shared challenges and opportunities exist among the countries of the region. The electricity network of the South East Europe region is highly interconnected, energy policies are increasingly harmonised and the electricity market increasingly integrated as a result of the EU accession process, the Energy Community Treaty and more recently the Energy Union initiative warranting a regional perspective on policy development.

A model-based assessment of different long term electricity investment strategies was carried out for the region within the scope of the SEERMAP project. The project builds on previous work in the region, in particular IRENA (2017), the DiaCore and BETTER EU research projects and the SLED project, as well as on EU level analysis, in particular the EU Reference Scenario 2013 and 2016. The current assessment shows that alternative solutions exist to replace current generation capacity by 2050, with different implications for affordability, sustainability and security of supply. In Bulgaria approximately 45% of current fossil fuel generation capacity, more than 2600 MW, is expected to be decommissioned by the end of 2030, and 97% of current fossil generation capacity will be decommissioned by 2050. This provides both a challenge for ensuring a policy framework which will incentivise investment in new generation, and an opportunity to reshape the electricity sector over the long term in-line with a broader economic strategy and unconstrained by the current generation portfolio.

A set of five models covering 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 Bulgaria can take:

- Under the two scenarios with an ambitious decarbonisation target and corresponding RES support schemes, Bulgaria will achieve an electricity mix with 53-54% renewable generation by 2050, composed primarily of wind, some hydro and solar. If renewable support is phased out and no CO_2 emission target is set, the share of RES in electricity consumption will reach around 33% in 2050.

- Delayed action on renewables is feasible, but has a serious disadvantage: the increased effort required towards the end of the modelled period to meet the CO_2 emissions target requires a significant jump in RES support in the 2045-2050 period.
- Whether or not Bulgaria pursues an active policy to support renewable electricity generation, a significant replacement of fossil fuel generation capacity will take place; coal and lignite capacities are almost completely phased out under all scenarios by 2050, accounting for less than 3% of today's level. The decline of fossil fuels begins early, and by 2030 close to 45% will be closed due to the rising price of carbon which results in unprofitable utilisation rates.
- Decarbonisation of the electricity sector does not drive up wholesale electricity prices compared to a scenario where no emission reduction target is set. 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 electricity production.
- Under all scenarios wholesale electricity prices increase compared with current, albeit historically low price levels. This is true for the entire SEE region- and in fact the EU as a whole- in all scenarios for the modelled time period. The widespread trend is driven by the price of carbon and the price of natural gas, both of which increase significantly by 2050. The macroeconomic analysis shows that the increase over time in household electricity expenditure relative to household income is significant in Bulgaria. In Bulgaria the electricity expenditure ratio to income will increase from the current 4 to 8 % by 2050. However, this increase is not induced by the RES support, as both the 'decarbonisation' and 'no target' scenarios present a similar trend. One benefit of higher wholesale prices is the positive signal it sends to investors in a sector currently beset by underinvestment.
- Natural gas will gain importance in the coming decades, its utilisation increases in all scenarios. Gas based generation rises early in the modelled period in the 'no target' and 'decarbonisation' scenarios replacing outgoing coal capacities. The importance of gas proves proves to be transitory in the 'decarbonisation' and 'delayed' scenarios, as in the last modelled decade gas based generation falls drastically. In the 'no target' scenario in 2050 however, the contribution of gas to the electricity mix in 2050 remains sizable, over 13% of total generation. This implies that Bulgaria might rely more heavily on gas imports in the middle time horizon, raising security of supply concerns, if no domestic gas resources are added to the resource pool.
- In all scenarios, Bulgaria will import electricity after 2035, but a decarbonisation policy has the benefit of reducing import dependency by 10 % compared to the 'no target' scenario.
- 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 (and RES support) in their investment decisions. From a social point of view, the high level of investment has a positive impact on GDP and a small positive impact on employment. At the same time, with higher levels of renewables, the external balance does not deteriorate, but maintains its baseline level.
- The need for support decreases as electricity wholesale prices climb and incentivise significant RES investment even without support. As the assessment shows, almost 40% of the newly installed RES generation would be realised even without further support for new RES generation by 2050.
- Required network investments in transmission and cross border capacities are not excessive (60 mEUR in 2030 and 32 mEUR in 2050 beyond capacities included in TYNDP

2016) if compared to the RES generation investment needs. However, our modelling does not cover the distribution network level, so these costs are not included in the figures.

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

- The high penetration of RES across all scenarios 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.
- RES potential can be maximised through policies eliminating barriers to RES investment. De-risking policies addressing high financing cost of capital prevalent throughout the region and in Bulgaria would pave the way for cost-efficient renewable energy investments.
- With current investment levels in Bulgaria and in the SEERMAP region far lower than projected in this roadmap, the countries are likely to need exogenous support to mobilise funds for these investments in networks and RES generation. The European Commission will be instrumental in initialising this process.
- In order to ensure that the modelled least cost energy system can be translated into reality, it is necessary to base renewable energy policies on sound analysis, take into account the interests of consumers and avoid institutional capture. This is particularly important as the vulnerability of consumers in Bulgaria is high, and ineffective implementation of policies may result in significant price increases, producing a backlash against renewable energy.
- Co-benefits of investing in renewable electricity generation can strengthen the case for increased RES investment, including a boost to GDP as a result of increased investment in generation capacity, an improved external balance due to reduced gas imports, and a lower wholesale energy price which can result from very high penetration of RES. Additional co-benefits, not assessed here, are health and environmental benefits from reduced emissions of air pollutants.
- In order to enable Bulgaria to transform its electricity sector to the level suggested by the EU Roadmap, an active, long-term and stable renewable energy support framework is needed. Projected RES support for decarbonisation of the electricity sector of Bulgaria can be covered by EU ETS revenues, thereby relieving the corresponding surcharge to consumers.
- Policy makers need to address the trade-offs presented by fossil fuel investments. Coal and lignite based generation capacities are expected to be priced out of the market before the end of their lifetime in all scenarios; this is also true for gas generation capacities under scenarios with an ambitious decarbonisation target, resulting in stranded assets. These long term costs need to be weighed against any short term benefits, particularly associated with gas, that temporarily bridges the transition from coal and lignite to renewables.
- Regional level planning, including establishment of regional markets, increasing cross-border capacities and incentivising storage capacities, can improve system adequacy compared with plans which emphasise reliance on national production capacities.
- Irrespective of the scenario implemented, Bulgaria may have to address the increased financial burden of electricity bills for households and a long term policy to address energy poverty may need to be developed. The evolution of wholesale electricity prices is driven by regional and European level supply and demand, and in an integrated and competitive European electricity market policy makers cannot protect consumers from price impacts with domestic investment decisions.

2 | Introduction

2.1 Policy context

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.

2.2 The SEERMAP project at a glance

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 the region: 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 (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.

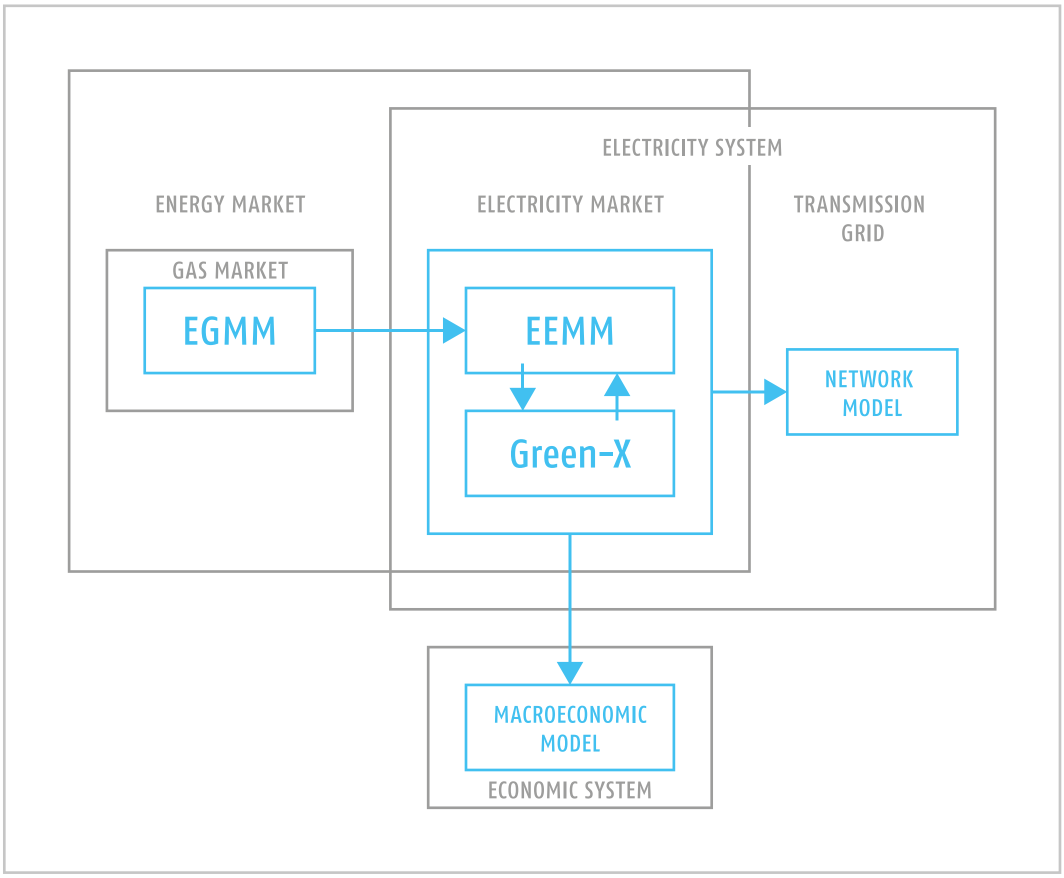
2.3 Scope of this report

This report summarises the contribution of the SEERMAP project to the ongoing policy debate on how to enhance the decarbonisation of the electricity sector in Bulgaria. We inform on the work undertaken, present key results gained and offer a summary of key findings and recommendations on the way forward. Please note that further information on the analysis conducted on other SEERMAP countries can be found in the individual SEERMAP country reports, and a Regional Report is also produced.

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

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")



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 allows for the incorporation of the impacts of EU market developments on the focus 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 load hours are represented, and that the impact of volatility in the generation of intermittent RES technologies on wholesale price levels is 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 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.

The 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

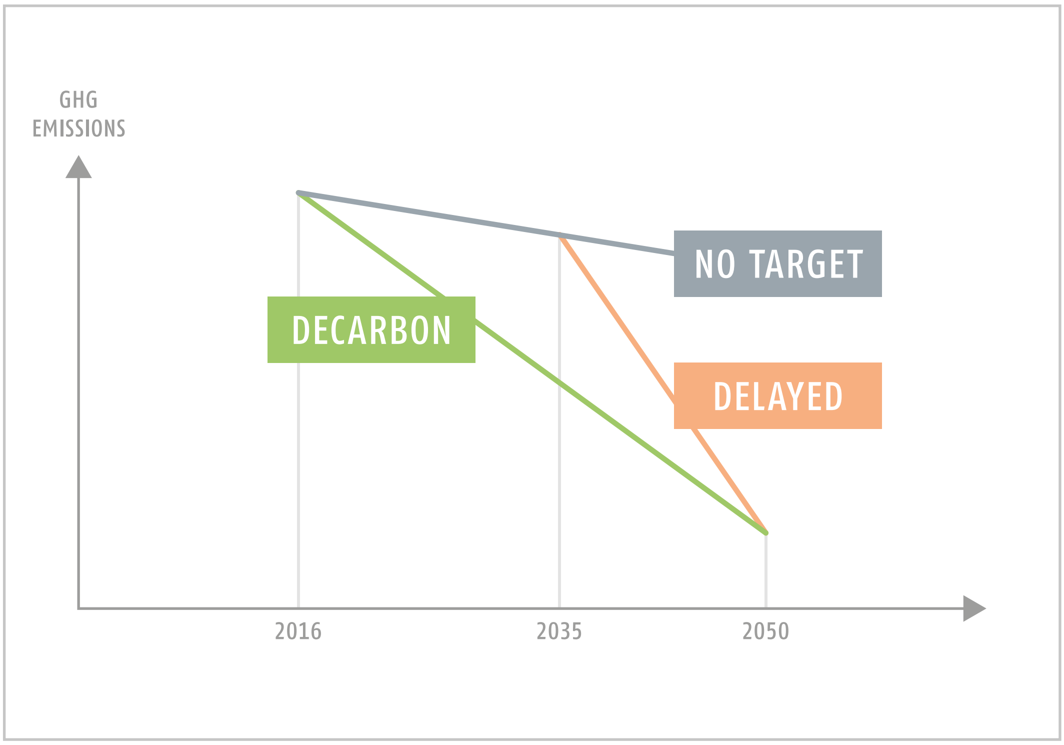
4.1 Scenarios

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 roadmap assesses 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 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.

FIGURE 2
THE CORE SCENARIOS



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. 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 Bulgaria, the starting year for the projections was 2015 for which actual data from ENTSO-E was available. The PRIMES EU Reference scenario growth rates were used from 2015 onwards due to lack of national long term projections. This means an average annual electricity growth rate of around 0.6% over the period between 2016 and 2050. The PRIMES EU Reference scenarios assume low levels of energy efficiency and low levels of electrification of transport and space heating compared with a decarbonisation scenario.
- 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 93% and oil prices by around 250%, because of historically low prices in 2016. Compared to 2012-2013 levels, this way only 15-20% increase of oil price is assumed by 2050. Cost of different technologies: Information on the investment cost of new generation technologies is taken from EIA Annual Energy Outlook (2017). In case of Bulgaria, new discoveries of natural gas fields in the Black Sea area could change the future supply and price level of natural gas. In this modelling we did not take into account any new gas discovery for Bulgaria on its Black Sea territory due to the high related uncertainty.
- 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 Bulgaria was assumed to be 10.7% in 2015 that stays virtually constant in the modelling period. The estimated WACC for onshore wind and PV are bit higher than the Ecofys – Eclareon (2017) estimates, where values are 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/tCO_2 in 2030 to 88 EUR/tCO_2 by 2050, in line with the EU Reference Scenario 2016.

Infrastructure:

- Cross-border capacities: Data for 2015 was available from ENTSO-E with future NTC values based on the ENTSO-E TYNDP 2016 and the 100% RES scenario of the E-Highway projection (ENTSO-E 2016).
- 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.

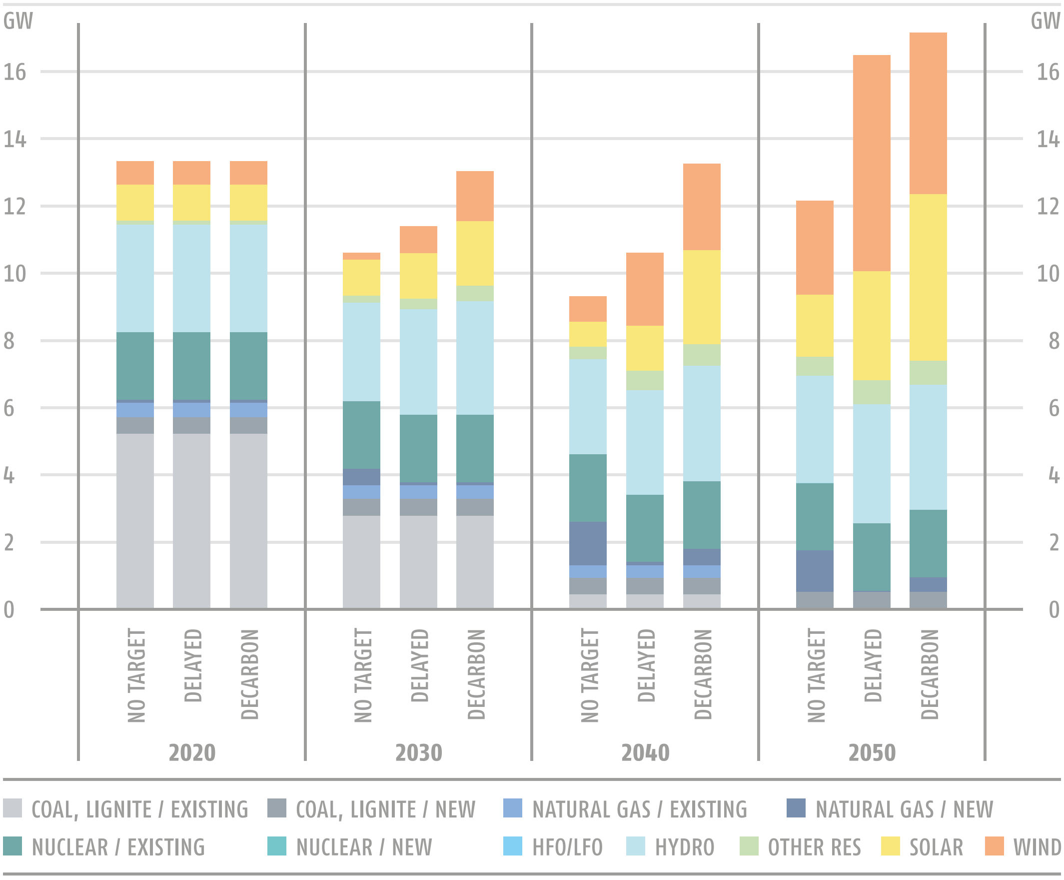
5 | Results

5.1 Main electricity system trends

Approximately 45% of current fossil fuel generation capacity, or more than 2600 MW, is expected to be decommissioned by the end of 2030, and 97% of today's fossil capacities will be decommissioned by 2050.

The model results show that in the emission reduction target scenarios the least cost capacity options are renewables (especially wind and solar, where capacity increase is highest) under the assumed costs and prices, while in the ‘no target’ scenario it is a mix of natural gas and renewables. The generation mix shifts significantly from fossil fuel towards renewables in all three scenarios, driven primarily by increasing carbon and wholesale electricity prices and decreasing renewable technology costs. Coal based electricity generation is nearly completely removed in all scenarios by 2050. Gas capacity shows significant growth in the ‘no target’ scenario, more than tripling its capacity. However, in the ‘delayed’ and ‘decarbonisation’ scenarios gas based generation plays only a transitory role, remaining below 2% in the ‘decarbonisation’ and 0% in the ‘delayed’ scenario by 2050.

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

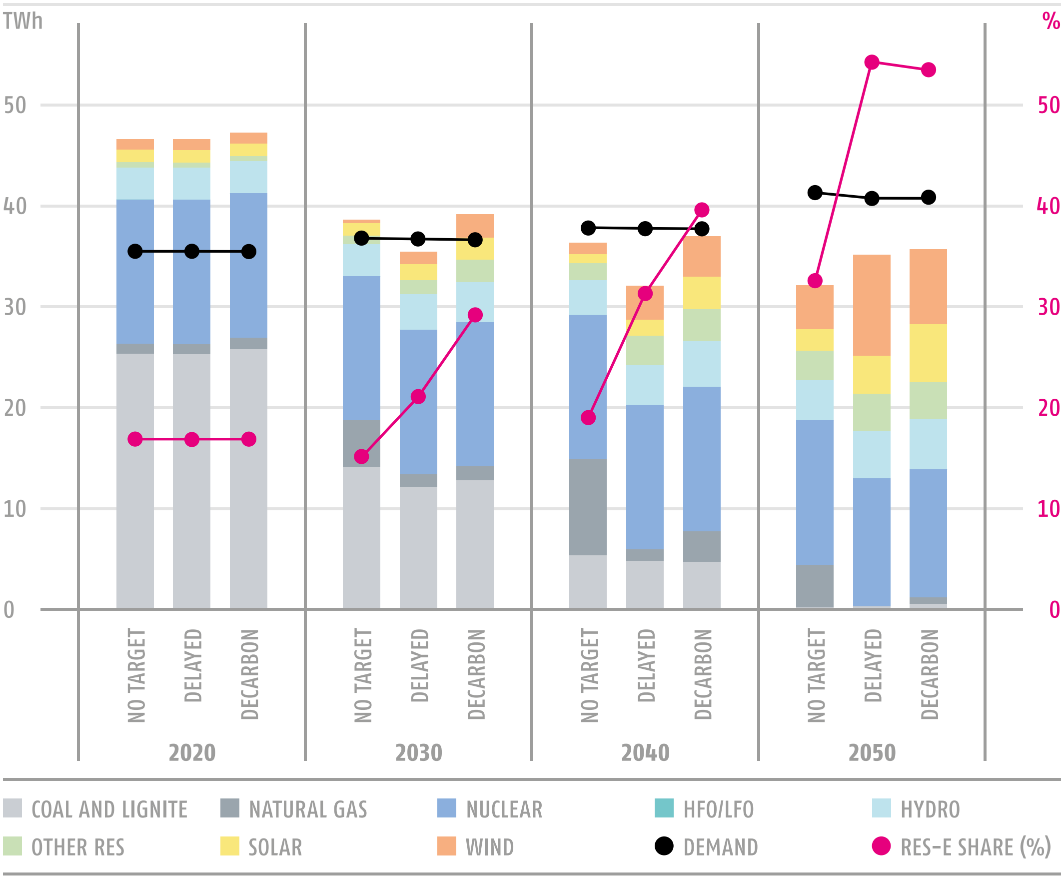


Renewables play an increasingly important role in all three scenarios. Major investments flow into wind and solar capacities in Bulgaria due to the combination of of favourable technical potential, decreasing technology costs, and the rising price of carbon and the increasing wholesale electricity price. Investment in solar is further encouraged by small scale photovoltaic installations that compete against end-user electricity prices, whereas other renewables such as wind technology compete with the wholesale electricity price. RES capacity stagnates in the 'no target' scenario until 2035 due to capacity retirement and lack of new investment, but shows dynamic growth after 2040 both in solar and wind capacity. Hydro capacity increases only by a few percentage points over the modelled time horizon in the 'decarbonisation' and 'delayed' scenarios, by 17% and 11% respectively. The share of biomass in the capacity mix increases but remains low in all three scenarios.

The present level of nuclear capacity is maintained across the whole modelled period with no new assumed capacity, but this is subject to change since a prospective nuclear plant appears on the policy agenda of the Bulgarian government in the autumn of 2017.

Natural gas plays a transitory role in electricity generation, peaking between 2030 and 2040 in all scenarios, but with a different contribution to the overall generation mix. In the 'decarbonisation' scenario gas based generation triples by 2035 compared to current levels, while in the 'no target' scenario gas based generation is more than ten times today's level. The 'delayed' scenario is an outlier, as gas based generation only slightly increases from current levels, demonstrating that Bulgaria could also opt for a less gas intensive pathway. The initial rise in gas based electricity generation is driven by the carbon price, which pushes out coal and lignite generation before sufficient renewable capacity is installed. Eventually, as the carbon price continues to rise and renewable technologies become cheaper, gas based generation declines.

FIGURE 4
ELECTRICITY GENERATION AND DEMAND (TWH) AND RES SHARE (% OF DEMAND) IN BULGARIA, 2020-2050



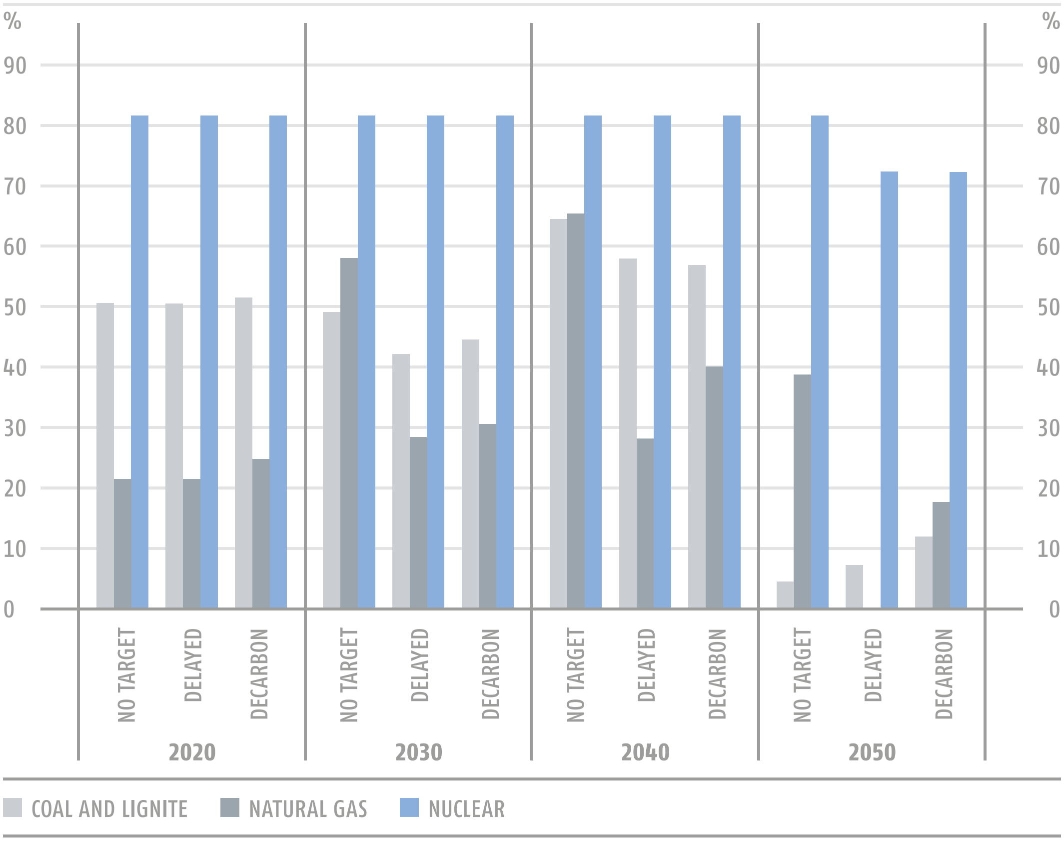
The pace of natural gas-fired power generation entering the system also depends on the future competitiveness of gas with other energy fuels. Currently, Bulgaria pays among the highest gas prices in Europe due to the complete dependence on a single source, Russia. The diversification of gas sources would become feasible with the arrival of Azeri gas in 2020/2021 and the expansion of virtual gas swaps involving LNG via the Greek-Bulgarian Interconnector (IGB).

In the 'decarbonisation' scenario gas acts as a bridge fuel for only a limited time period, displacing some coal and lignite generation on the path to decarbonisation until 2040. In the 'delayed' scenario the bridging role is more limited, with peak gas consumption only 25% higher than current levels. This can be achieved in both scenarios with a moderate increase of natural gas capacities since the increase in generation is mostly due to higher utilisation rates. Following the initial growth in natural gas based generation, it falls significantly after 2040 and continues to slide below 2% of total electricity generation by 2050. In the 'no target' scenario gas still contributes 13% to the total electricity generation in 2050.

In contrast to its present net export position, Bulgaria becomes a net importer in all three scenarios beyond 2035. By 2050, net imports increase to more than 22% in the 'no target' scenario, but remains below 14% of total consumption in the other two scenarios. This is the result of a more moderate growth in RES generation compared to some neighbouring countries (e.g. Greece and Romania). Trade patterns are very volatile as minor price changes can alter the export/import positions of neighbouring countries, e.g. between Bulgaria and Greece or Bulgaria and Romania.

Concerning the renewable developments, wind generation becomes a key source beyond 2040. Gas is mostly displaced in the 'decarbonisation' and 'delayed' scenarios by the increasing carbon price which makes wind, but also solar and biomass, more competitive.

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



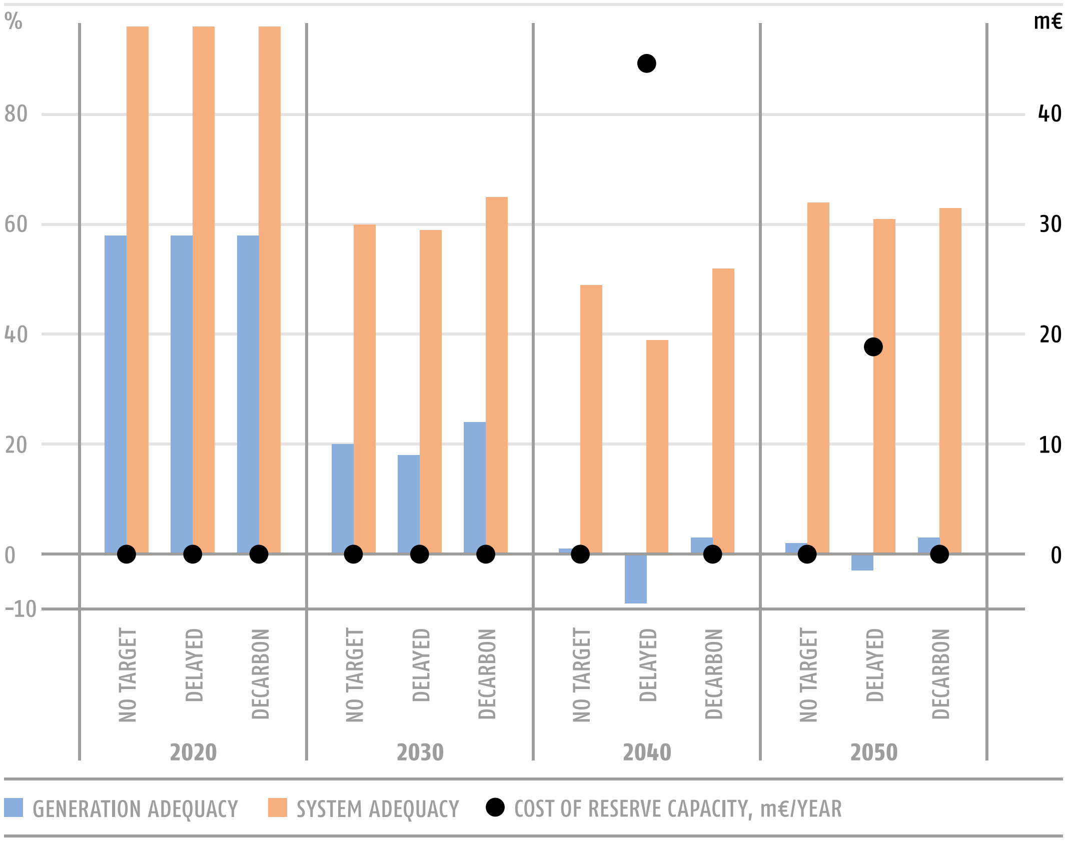
The utilisation rate of coal plants remains relatively stable until 2030, and even slightly increases to close to 60% by 2040 in all scenarios. Utilisation rates drop below commercially viable levels by 2045, reaching as low as 5% to 12% by 2050. This shows that at carbon price level of 50 EUR/tCO_2, coal based capacities will not be competitive. Gas utilisation rates are rather low in the two scenarios with a decarbonisation target, remaining below 35%, but reach high levels in the 'no target' scenario. Coal investments made at any time during the modelled time period will result in stranded assets. This issue is discussed further in section 5.4.

An additional insight from the scenario modelling relates to the utilisation rate of nuclear generation, also affected by the increased RES based production in the 'delayed' and 'decarbonisation' scenarios. The standard 80% utilisation rates drops by 10% in the 2040 – 2050 period, signalling that RES based generation will be more competitive in certain hours of the year, when even relatively cheap nuclear generation will reduce output. With additional planned nuclear capacity, utilisation rates could be even lower

5.2 Security of supply

Even though the physical and commercial integration of national electricity markets naturally improves security of supply, concern of decision makers are often remain regarding the extent and robustness of this improvement, particularly in the context of a high share of renewables. In order to assess the validity of these 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.

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



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, 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 the lowest value was taken as the generation adequacy margin indicator. For this calculation, assumptions were made with respect to the maximum availability of different technologies. Fossil fuel power plants were assumed to be available 95% of the time, and hydro storage 100% of the time. For other RES technologies historical availability data was used. System adequacy was defined similarly but net transfer capacity available for imports is 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 Bulgaria, the generation adequacy margin is positive up to 2035, but becomes negative or very close to zero in the post-2030 period. Negative values mean that domestic generation capacity would be insufficient to satisfy domestic demand during all hours of the year for all of the years modelled after 2040. Negative values can be observed in the 'delayed' scenario, but in the other scenarios the generation adequacy index also stays very close to zero. The system adequacy margin is positive throughout the whole modelling period.

For negative generation adequacy indicators the cost of reaching a zero generation adequacy margin was calculated. This is defined as the yearly fixed cost of an open cycle gas turbine (OCGT) which has sufficient capacity to ensure that the generation adequacy margin reaches zero. This cost for Bulgaria is significant in the 'delayed' scenario, up to 45 mEUR/year in 2040. This demonstrates the importance of regional markets and interconnections as a way of reducing costs in the 'delayed' scenario.

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 calculation did not account for greenhouse gases other than CO_2 and does not include emissions related to heat production from cogeneration.

The 94% overall decarbonisation target for the EU28+WB6 region translates into a higher than average level of decarbonisation in the Bulgarian electricity sector. By 2050 CO_2 emissions from the electricity sector in Bulgaria compared to 1990 levels are reduced by 96.7 to 98.6% in the two scenarios with a decarbonisation target as a result of increasing RES and maintained nuclear generation. Emissions fall significantly in the 'no target' scenario, with 93% by 2050 owing to high carbon price and also nuclear generation.

The share of renewable generation as a percentage of gross domestic consumption in 2050 is 32% in the 'no target', 54% in the 'delayed' and 53% in the 'decarbonisation' scenario. Compared to other countries in the region, Bulgaria has lower shares of RES generation, mainly due to the existing 2000 MW nuclear capacity, and lower hydro capacity. It is worth noting that the nuclear capacity at Kozloduy will be closed right after the modelled period, posing an additional challenge to the decarbonisation of the Bulgarian electricity system. In the scenario with the highest RES share in 2050 (the 'delayed' scenario) long term RES potential utilisation reaches 63% for hydro, 64% for wind and 33% solar. This means that approximately two thirds of Bulgarian hydro and wind potential will be utilised by the end of the modelled period, if this scenario is implemented. These high utilisation rates in wind and hydro reflect the relatively lower potential of Bulgaria, rather than an exceptionally dynamic investment pattern in RES compared to the neighbours.

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. The price trajectories are independent of the level of decarbonisation and similar in all scenarios, only diverging 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 of end user prices and could affect affordability for consumers. The average annual wholesale price increase in Bulgaria over the entire period is 2.9% in the 'no target' scenario and 2.3% in the two decarbonisation scenarios. The lower growth rate in the latter two scenarios is attributable to a decrease in the wholesale price during the last 5 years of the modelled time period. Although the price increase is high, 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 price levels 10 years ago. The macroeconomic analysis shows that household electricity expenditure will double in the 'no target' and 'decarbonisation' scenarios compared with current levels. The increase in the 'delayed' scenario is even higher. The price increase also has

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

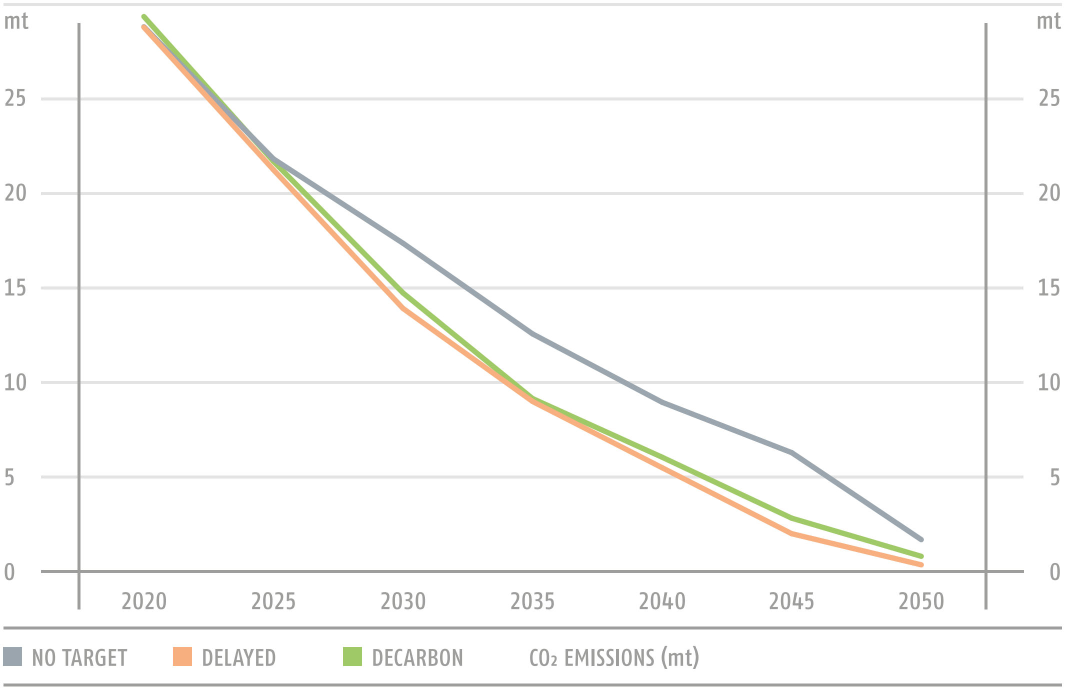


FIGURE 8
WHOLESALE ELECTRICITY PRICE IN BULGARIA, 2020-2050 (€/MWh)

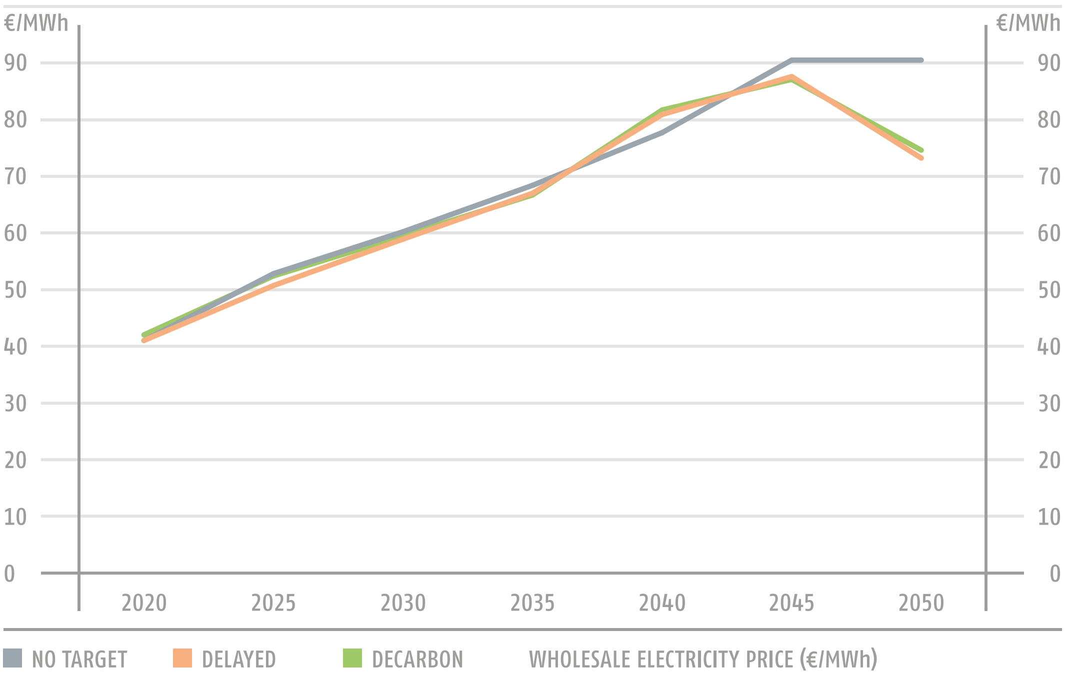
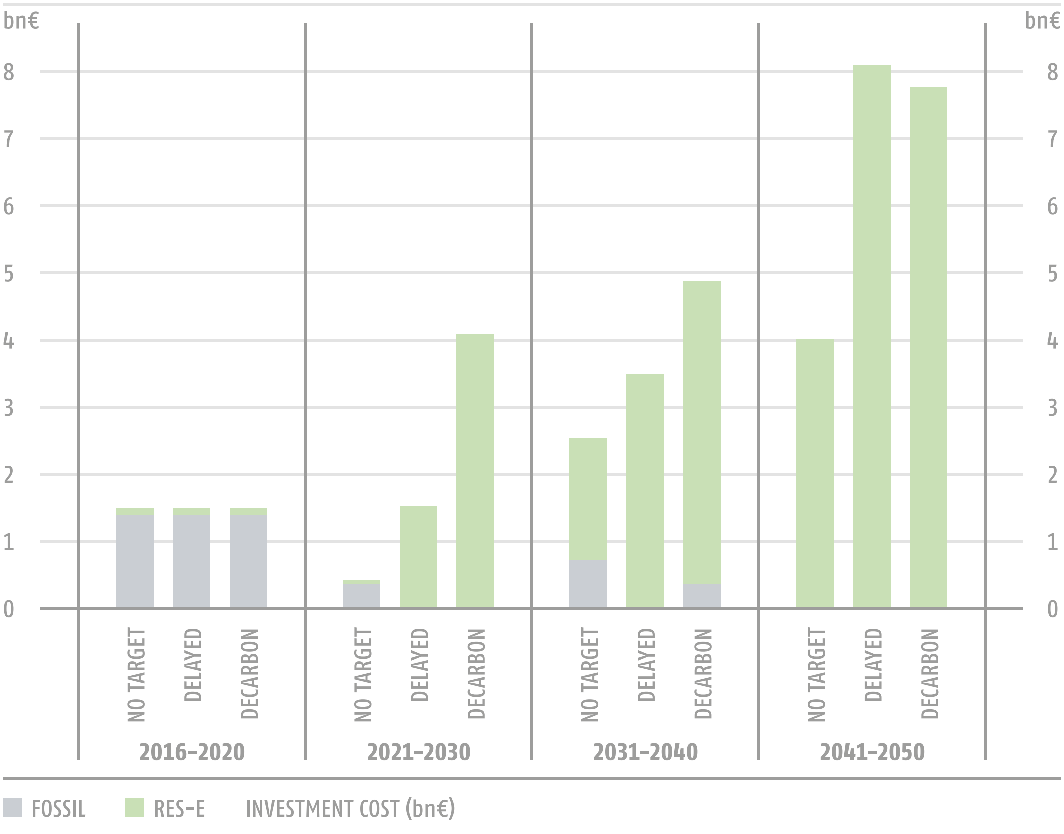


FIGURE 9
CUMULATIVE INVESTMENT COST FOR 4 AND 10 YEAR PERIODS, 2016-2050 (bn€)



three positive implications, incentivising investment for new capacities, incentivising energy efficiency and reducing the need for RES support.

The investment needed in new generation capacities increases significantly over the entire modelled time period. Investment is particularly high in the 'decarbonisation' scenario between 2030 and 2040 and in the 'delayed' scenario between 2040 and 2050, reflecting the significant requirements for meeting decarbonisation targets at the end of the period. Meanwhile, investment needs are lowest in the 'no target' scenario from 2020 throughout the entire modelling period.

It is important to note that investments are assumed to be based on a profitability requirement (apart from the capacities planned in the national strategies) and financed by private actors. These actors factor 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 a change in the overall investment level are limited to the impact on GDP, employment, as well as to the impact on the fiscal and external balance. These impacts are discussed in more detail in section 5.7.

Despite the high investment requirements associated with the two emission reduction target scenarios, the renewables support needed to incentivise these investments decreases over time with the exception of the last 5 years in the 'delayed' scenario. RES support relative to the wholesale price plus RES support in the 'decarbonisation' scenario is less than 15.9% in the 2020-2025 period, but only 1.8% in 2045-2050.

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. This is partly due to the locational impact: as the best locations with highest potential are used first, therefore, the levelised cost of new RES capacities might increase over time. The relationship between the

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

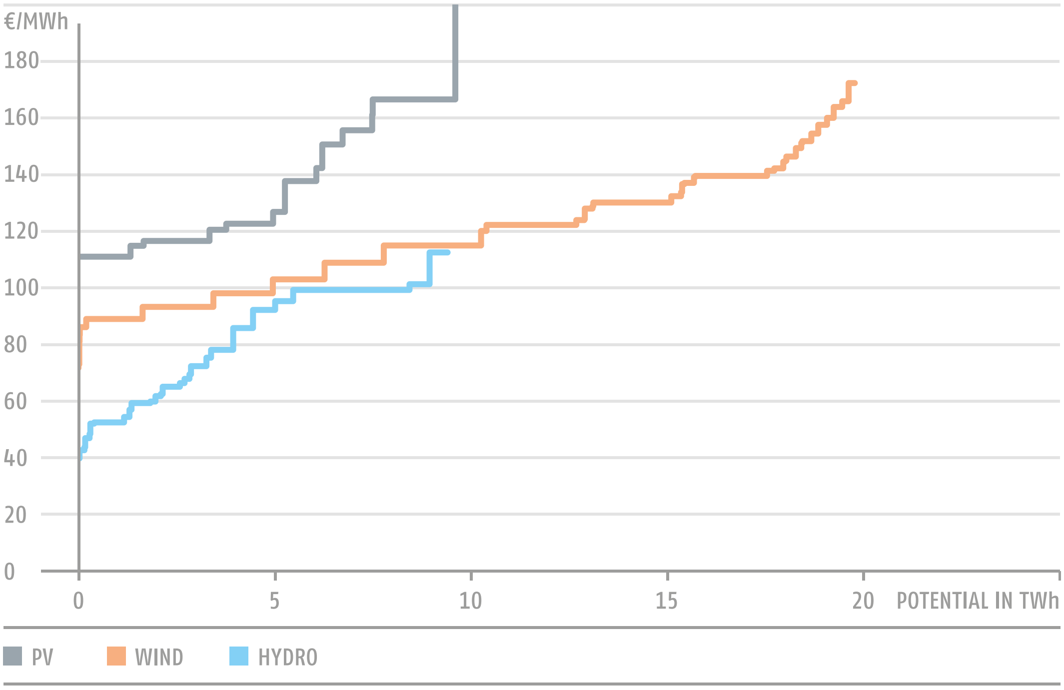


FIGURE 11
AVERAGE RES SUPPORT PER MWh OF TOTAL ELECTRICITY CONSUMPTION AND AVERAGE WHOLESALE PRICE, 2016-2050 (€/MWh)

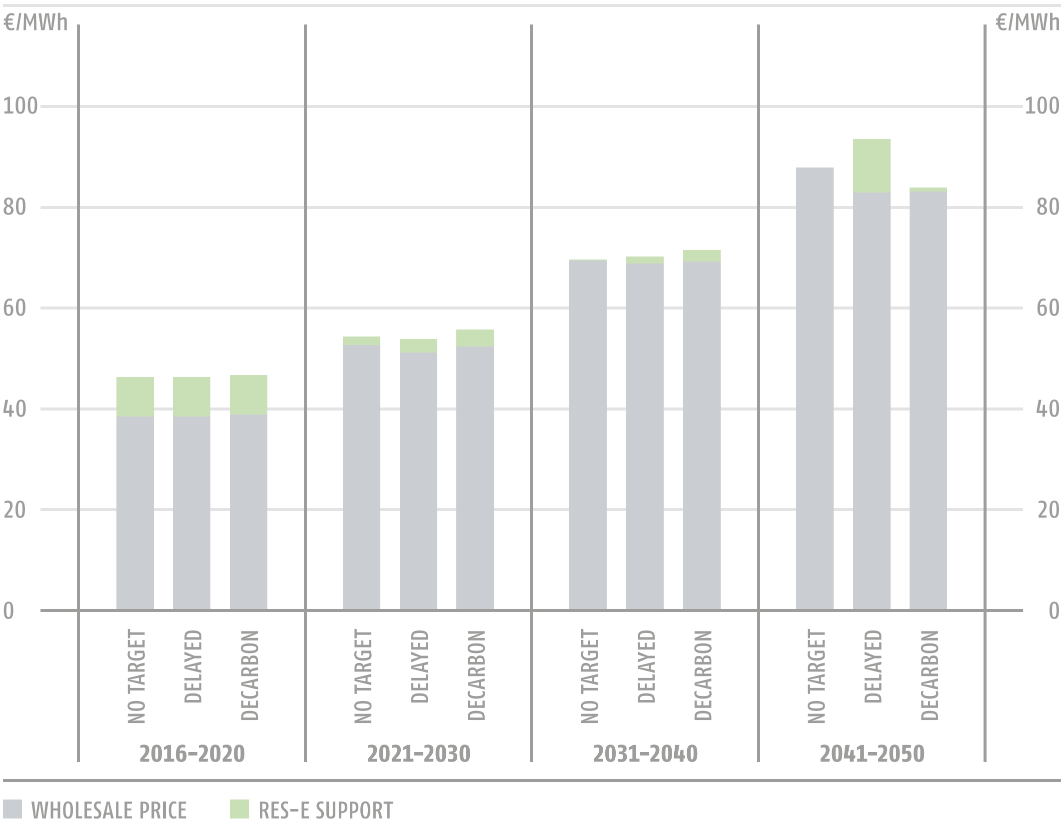
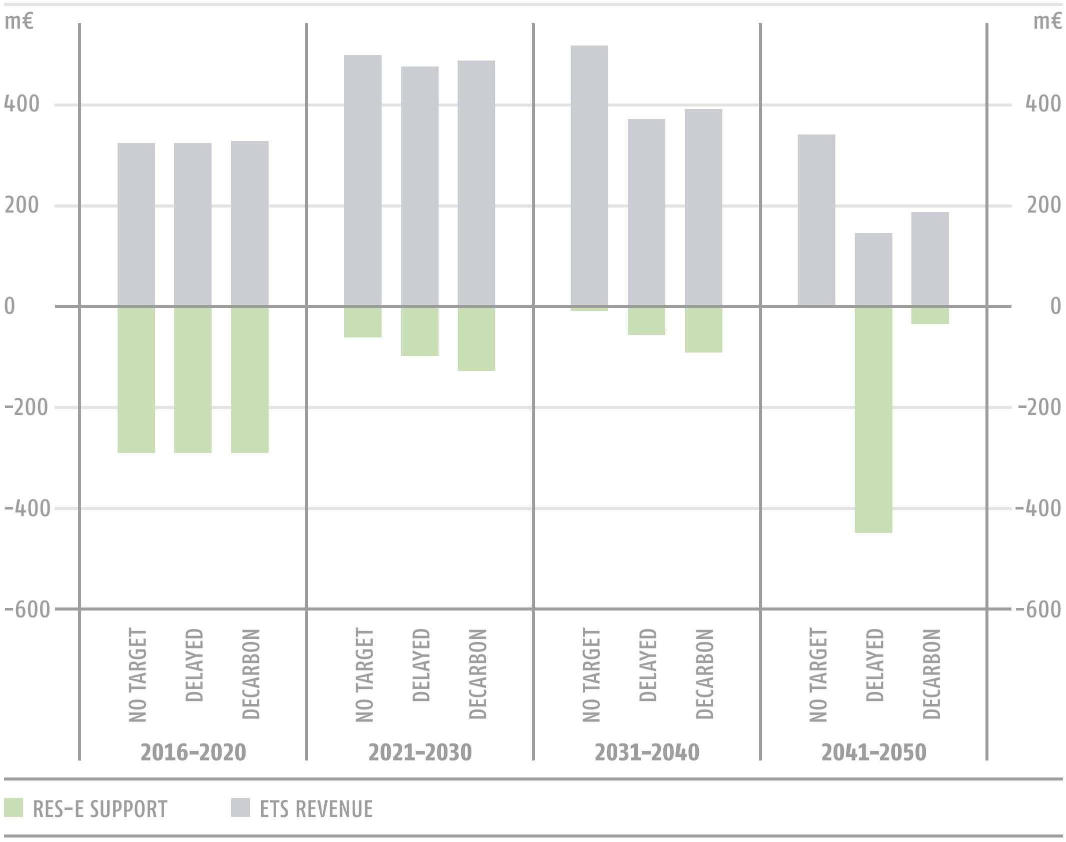


FIGURE 12
CUMULATIVE RES SUPPORT AND AUCTION REVENUES FOR 4 AND 10 YEAR PERIODS, 2016-2050 (m€)



cost of RES technologies and installed capacity is shown in Figure 10; although the figure does not account for the learning curve impacts which were also considered in the Green-X model.

RES support falls over the course of the modelled period while investment in RES capacity increases, with the exception of the last decade in the 'delayed' scenario when significant investment is needed in renewables translating to high levels of RES support. 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 with a number of support schemes using funding from different sources; in the model sliding feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is a potential source of financing for renewable investment. Figure 12 contrasts cumulative RES support needs with ETS auction revenues, assuming 100% auctioning, and taking into account only allowances to be allocated to the electricity sector. In the 'decarbonisation' and 'delayed' scenarios, auction revenues decrease significantly by the end of the modelled time period because fossil fuel plants receiving allocations mostly disappear from the Bulgarian capacity mix. Overall the modelling results show that ETS revenues can cover the necessary RES support over the modelled period, with the exception of the 'delayed' scenario, where in the period of 2046-2050 RES support is three times higher than the decreasing ETS revenues.

A financial calculation was carried out on the stranded costs of fossil based generation plants that are expected to be built in the period 2017-2050. New fossil generation capacities included in the scenarios are defined either by national energy strategy documents and entered into the model exogenously, or are built by the investment algorithm of the EEMM. The model's investment module assumes 10 year foresight, meaning that investors have limited knowledge of the policies applied in the distant future. The utilisation rate of fossil fuel generation assets drops below 15% in most SEERMAP countries after 2040; this means that capacities which generally need to have a 30-55 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.

Large stranded capacities might call for public intervention with all the associated cost borne by society/electricity consumers. For this reason we have estimated the stranded costs of fossil based generation assets that were built in the period 2017-2050. The calculation is based on the assumption that stranded costs will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) for over a period of 10 years after these gas and coal based capacities become unprofitable. Based on this calculation early retired fossil plants would have to receive 2.5 EUR/MWh, 2.2 EUR/MWh and 2.3 EUR/MWh surcharge over a 10 year period to cover their economic losses in the 'no target', 'delayed' and 'decarbonisation' scenarios respectively. This stranded cost is mostly attributable to the lignite plant planned to be finalised by 2018, and to a lesser extent the gas fired plants to be built in the future. These costs are not included in the wholesale price values shown in this report. New nuclear capacities could also result in stranded costs with lower than expected utilisation rates, however this situation was not modelled in the present work.

5.5 Sensitivity analysis

In order to assess the robustness of the results, a sensitivity analysis was carried out with respect to assumptions that were deemed most controversial by stakeholders during consultations and tested for the following assumptions:

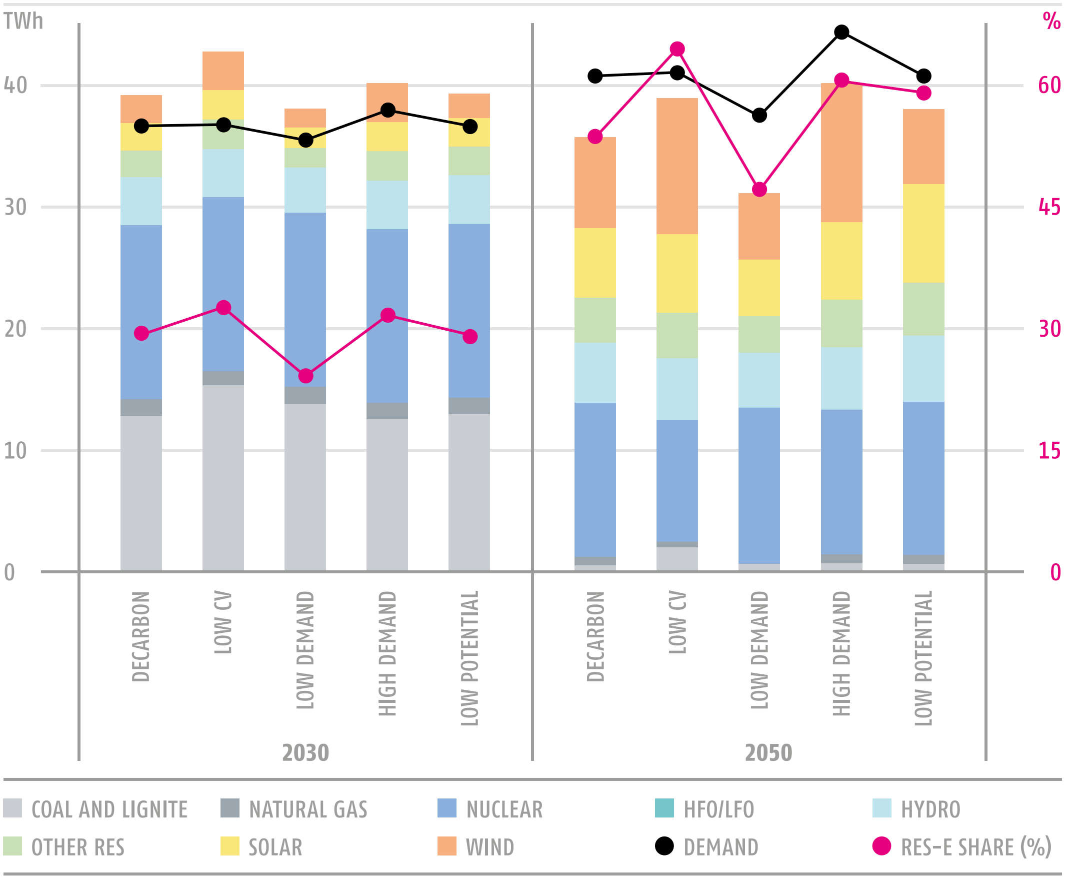
- Carbon price: to test the impact of a lower CO_2 price, a scenario was run which assumed that CO_2 prices would be half of the value used for the three core scenarios for the entire period until 2050;
- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the growth 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 changes in assumptions were only applied to the 'decarbonisation' scenario since it represents a significant departure from the current policy for many countries, and 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.

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

- The CO_2 price is a key determinant of wholesale prices. A 50% reduction in the value of the carbon price results in an approximately 33% reduction in the wholesale price over the long term. However, this wholesale price reduction is more than offset by the need for higher RES support.
- A lower carbon price would increase the utilisation rates of coal power plants by 8.7% in 2030 and by 31.9% in 2050 in Bulgaria. However, this is not enough to make coal competitive by 2030 as significantly higher utilisation rates are required to avoid plant closure.
- Gas utilisation rates fall with lower carbon prices.

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



- Change in demand has only a limited impact on fossil fuel capacities and generation. RES capacity and generation, notably PV and wind, are more sensitive to changes in demand.
- Lower hydro and wind potential results in increased PV capacity and generation. As solar is a more expensive technology option than hydro or wind, a significant increase in RES support is required in this sensitivity assessment compared with the 'decarbonisation' scenario.

5.6 Network

Bulgaria's transmission system is connected to each neighbouring country at weak or moderate levels, with the strongest connection to Greece with 500 MW net transfer capacity. In the future, significant additional network investments are expected to accommodate higher RES integration, cross-border electricity trade, and significant growth in peak load. Bulgaria is currently building the Maritsa East 1 – Nea Santa 400 kV power interconnector with Greece, which would add another 1,500 MW of transfer capacity by 2021. The recorded peak load for Bulgaria in 2016 was 7015 MW (ENTSO-E DataBase), while it is projected to be 8017 MW in 2030 (SECI DataBase) and 8935 MW in 2050. Consequently, there will be a need for further investment in domestic high and medium voltage transmission and distribution lines.

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

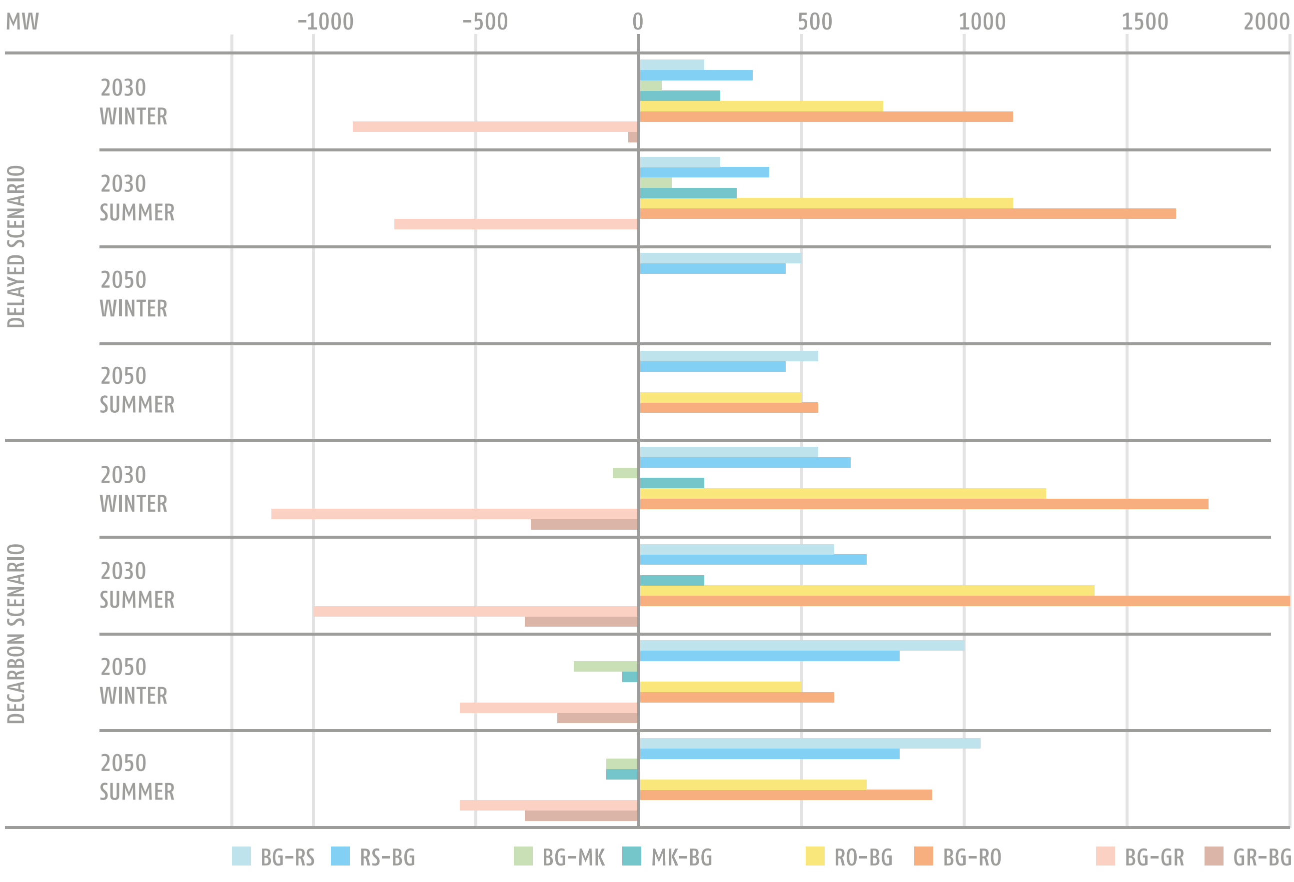


FIGURE 14
NTC VALUE CHANGES IN 2030 AND 2050 IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS COMPARED TO THE 'BASE CASE' SCENARIO

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

- **Contingency analysis:** Analysis of the network constraints anticipates contingencies in the Dobruja region and at the Serbian and Romanian borders. These problems could be resolved with investments in the transmission network, at estimated costs of 60 mEUR in 2030 and 32 mEUR in 2050. The possible solutions are listed in the following table, indicating the location and investment cost levels of the proposed development.

TABLE 1 | OVERLOADINGS IN THE BULGARIAN SYSTEM, 2030 AND 2050

Time	Trippings	Overloading	Solution	Units (km or pcs)	Cost m€
2030	New RESs	OHLs 110 kV in the area of Dobruja region (BG)	New 400kV double circuit OHL to accommodate 2000 MW RES generation in N-E Bulgaria (Dobruja region)	70	25
	New RESs	OHLs 110 kV in the area of Dobruja region (BG)	New 400 kV 140km single circuit parallel to the existing one Varna (BG) – Burgas (BG)	140	35
2050	OHL 400 kV Nis (RS) – Sofia (BG)	OHL 400 kV Stip (MK) – Ch Mogila (BG)	OHL Double Circuit 400 kV Nis (RS) – Sofia(BG) 2nd line. Due to large RESs scaling in Greece and large import of Serbia	90	31
	OHL 400 kV Djerdap (RS) – Portile de Fier (RO)	OHL 400 kV Nis (RS) – Sofia (BG)	OHL Double circuit 400 kV Djerdap (RS) – Portile de Fier(RO) 2nd line. Due to large RESs scaling in Romania and Greece and large import of Serbia	2	0.7

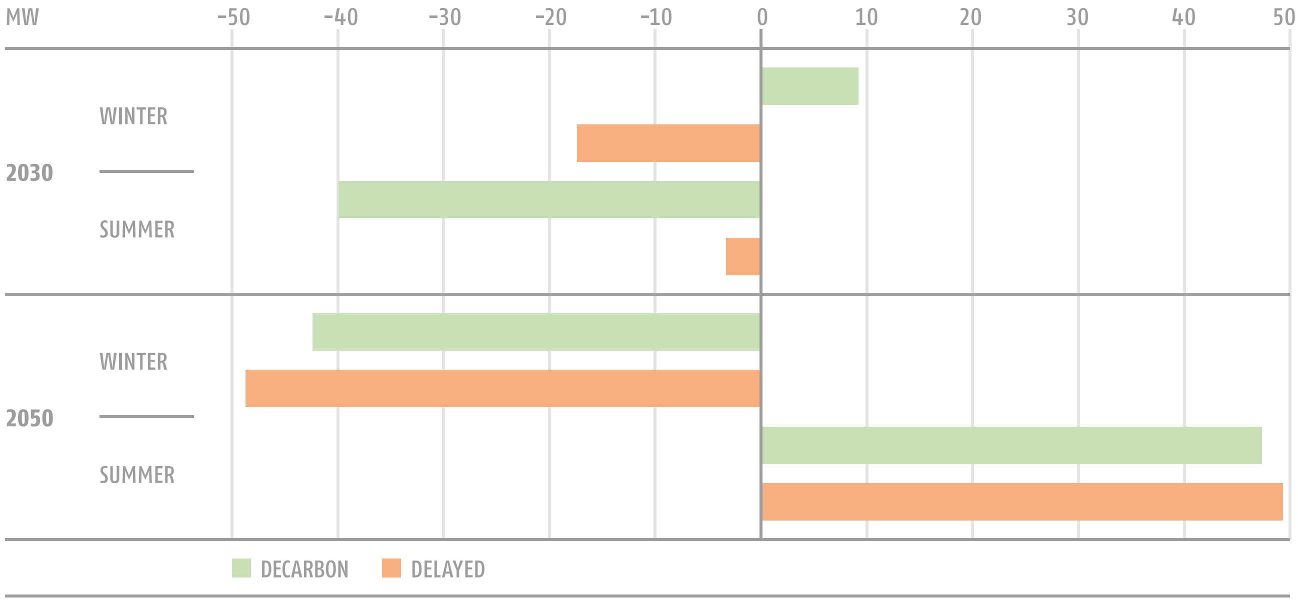


FIGURE 15 LOSS VARIATION COMPARED TO THE BASE CASE IN THE 'DELAYED' AND 'DECARBONISATION' SCENARIOS (MW, NEGATIVE VALUES INDICATE LOSS REDUCTION)

- **TTC and NTC assessment:** Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between Bulgaria and bordering countries 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 Bulgarian and neighbouring electricity systems. Figure 14 depicts the changes in NTC values for 2030 and 2050, revealing two opposite outcomes from higher RES deployments on the NTC values. First, the high concentration of RES in a geographic area may cause congestion in the transmission network, reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity it may increase NTC for a given direction.

  As the results show, NTC values increase in the RES intensive 'decarbonisation' and 'delayed' scenarios, with the exception of the GR-BG border, compared to the 'base case' scenario. This shows that the import substitution effect is stronger in Bulgaria than the 'congestion' impact of RES. The most affected direction is BG to RO relation, where NTC values generally increase over 500 MW, but in some cases even over 1000 MW.

- **Network losses:** Transmission network losses are affected in different ways. For one, losses are reduced as renewables, especially PV, are mostly connected to the distribution network. However, high levels of electricity trade observable in 2050 will increase transmission network losses. Figure 15 shows that in the 'decarbonisation' and 'delayed' scenarios transmission losses change significantly compared to the 'base case' scenario, but no clear trend could be observed.

  As Figure 15 illustrates, changes in loss reduction do not show a consistent pattern. In 2030, loss reduction occurs (in the range of 40-70 GWh/year) but for 2050 winter and summer seasons the loss reduction pattern is very volatile, and the net effect is close to zero.

  Required network investments in transmission and cross border capacities are not excessive (60 mEUR in 2030 and 32 mEUR in 2050 beyond capacities included in TYNDP (2016) if compared to the RES generation investment needs. It has to be emphasised that the calculated investment requirements only cover the transmission while the more affected distribution network developments and their cost are not modelled.

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

5.7 Macroeconomic impacts

A 'baseline' scenario differing from the three core scenarios was constructed for the macro-economic analysis to serve as a basis for comparison whereby 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 and no additional renewable support is included beyond existing policies. The 'baseline' scenario assumes lower levels of investment than the three core scenarios.

After an initial take-up in GDP related to the recovery after the financial crisis, growth will slow to 1.2% per annum by 2025. This is reflective of weak fundamentals due to low productivity, large-scale emigration and an aging population, however there are signs of some positive developments – increasing backflow of migrants and growing shares of high value added sectors (e.g. IT, financing). Gross government debt is likely to remain at roughly the current low level of 20% of GDP throughout the modelled time horizon. At the same time, external debt, mostly reflecting private sector indebtedness, will gradually decline due to the ongoing deleveraging of the corporate sector.

The 4.3% share of household electricity expenditure to income is higher than the regional average in 2016. The baseline scenario projects electricity expenditure to income to rise significantly to around 8.5% by 2050 as a result of several countervailing forces. The real wholesale energy prices are expected to grow by over 80% by 2050, however, the phase out of RES support schemes reduces the retail price level by over 28%.

The core scenarios are characterized by moderate additional investment efforts compared to the baseline scenario, as even in the most intensive periods, the additional investment is around 0.5% of GDP. The 'no target' scenario does not deviate significantly from the baseline, while in the 'decarbonisation' scenario, the intensive investment 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 evaluated 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

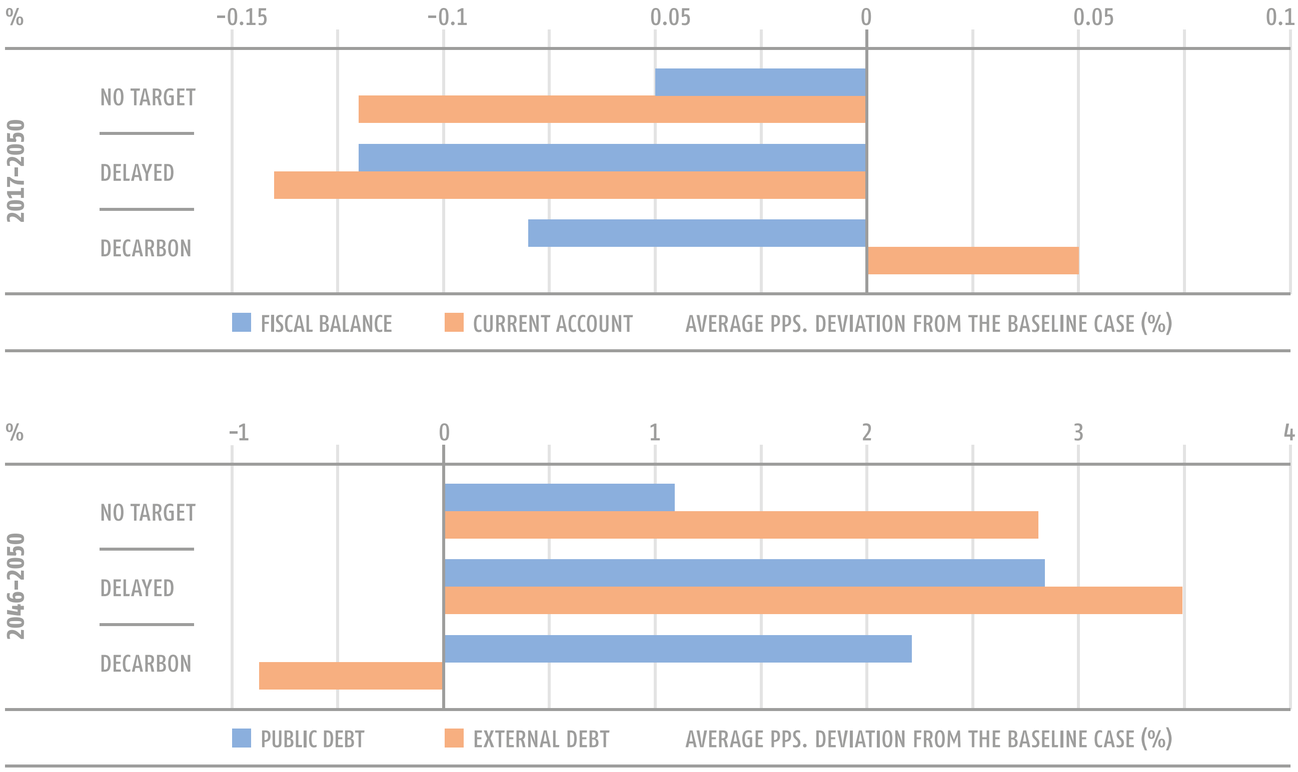


FIGURE 17
PUBLIC AND EXTERNAL BALANCES AND DEBT IMPACTS COMPARED WITH THE 'BASELINE' SCENARIO

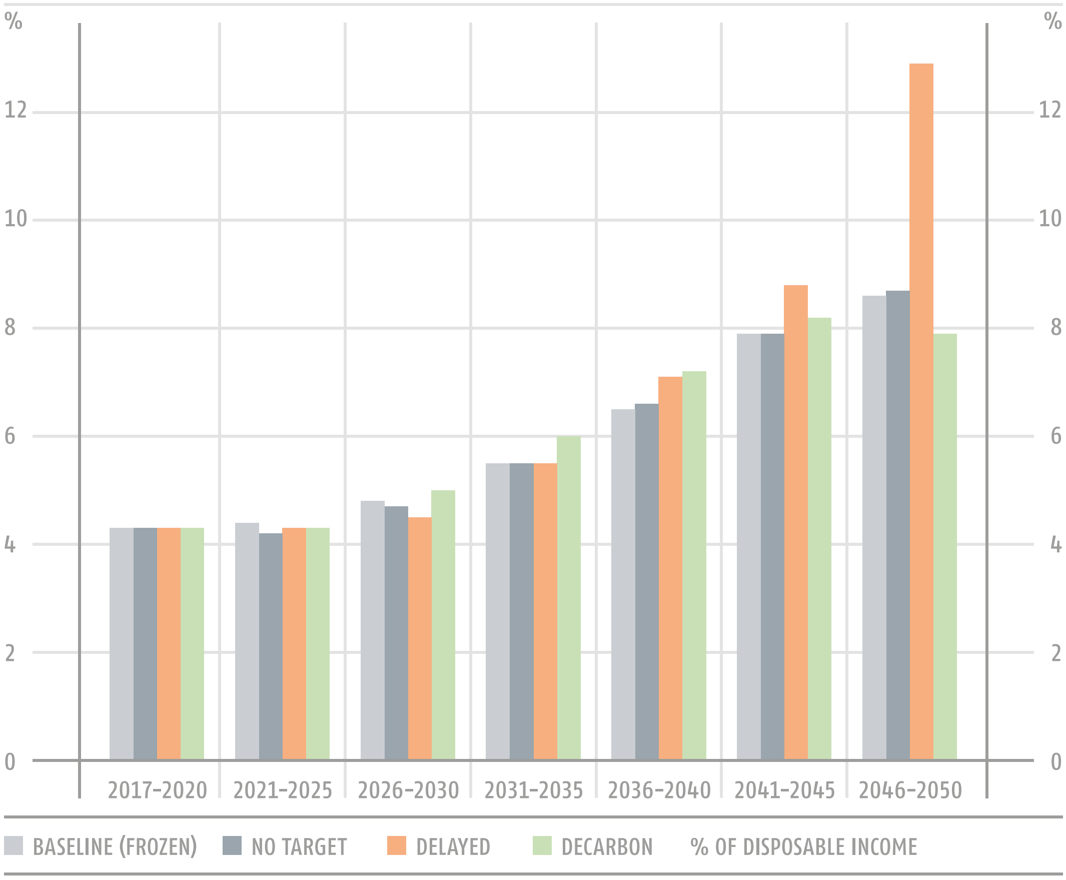
GDP and employment across two time dimensions. First, the average difference over the whole time horizon (2016-2050) is compared with the baseline. Then the long term effect is determined by the deviation from the baseline in the period 2046-2050. It is important to note that because the population remains the same across scenarios GDP gains also reflect GDP per capita effects.

Overall, the results imply small macroeconomic gains from the core scenarios. In the 'decarbonisation' scenario, the GDP level is on average 2% higher compared to the baseline scenario in 2050, with a long term GDP effect of 4%. Gains are more moderate in the 'delayed' scenario, at around 1% on average and 2.5% in the long term, and practically zero in the 'no target' scenario. Employment effects are marginal, around 0.2-0.3% on average for 'decarbonisation' and 'delayed' scenarios compared to the baseline, while the effects are slightly higher in the long term. At the same time, the 'no target' scenario has practically no effect on employment.

It is important to stress that long term GDP gains are present in the 'decarbonisation' and 'delayed' scenarios due to the higher level of productive capacities in the economy. These long term gains come from two sources. First, the extra investment efforts raise the level of productive capital in the economy. Second, the newly installed, mainly foreign technologies increase overall productivity. The lower employment gains compared to GDP effect is explained by two factors: (i) the energy investments are relatively capital intensive, and (ii) the initial employment gains are translated to higher wages in the longer term, as labour supply remains the same across scenarios. Nevertheless, in the 'delayed' scenario the employment effect is slightly higher in the long term than in the medium term, due to the relatively intensive investment efforts concentrated at the end of the modelled horizon.

The macroeconomic vulnerability calculation captures how the additional investments contribute to the sustainability of the fiscal and external positions of the country measured

FIGURE 18
HOUSEHOLD ELECTRICITY EXPENDITURE 2017-2050



by the fiscal and external balances and the public and external debt indicators. While the fiscal and external balances are compared to the 'baseline' scenario over the whole projection horizon (2017-2050), the debt indicators focus on the long term effects, with the difference from the baseline only calculated at the end of the modelled period. This approach is consistent with the fact that debt is accumulated from past imbalances.

The three core scenarios do not significantly change the macroeconomic vulnerability of Bulgaria. Long term external debt increases by around 3% of GDP in the 'no target' and 'delayed' scenarios, while slightly declining in the 'decarbonisation' scenario. This reflects shifts in the current account due to changing net energy imports compared to the baseline. Higher RES-based generation leads to lower imports of fossil fuels, and hence to a lower trade deficit, which before the economic crisis in 2008 had reached more than 10% of GDP. The scenarios have an even lesser effect on the fiscal deficit and public debt, although the fiscal deficit is higher in the second half of the period due to the lower CO_2 revenues.

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

Affordability deteriorates in the 'delayed' scenario as there is a close to 40% increase in household electricity expenditure relative to disposable income at the end of the modelled period compared to the baseline due to more intensive renewable support. At the same time, in the 'decarbonisation' scenario, electricity expenditure declines by close to 10% in the 2046-2050 period compared to the baseline, primarily due to the fall in wholesale electricity prices. The 'no target' scenario does not differ substantially from the baseline case in terms of affordability.

6 | Policy conclusions

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

MAIN POLICY CONCLUSIONS

Regardless of whether Bulgaria pursues an active electricity sector decarbonisation policy, a significant shift away from fossil fuels towards renewables will take place:

- Due to aging power plants Bulgaria will need to replace approximately 97% of its existing conventional generation fleet by 2050;
- Lignite and coal based capacity will comprise 7-10% of total capacity by 2040 and only 3-4% by 2050;
- Natural gas plays a transitional role on the path towards low carbon generation in the 'delayed' and 'decarbonisation' scenarios. However in the 'no target' scenario its capacity triples compared to the present level and generates more than 10 times more electricity than today at its peak in 2040;
- The high penetration of RES across all scenarios suggests that Bulgarian energy policy should focus on enabling RES integration;
- The significant investment requirements could be reduced by de-risking policies in RES support, reducing the financial burden of investors. Also international funds can help to increase investment activities in the region, where the EC could make a positive impact.

A long term planned policy to support renewable generation is worth it:

- The 'decarbonisation' scenario shows that it is technically feasible and financially viable for Bulgaria to reach 96.7% emission reduction with its RES resources and nuclear generation by 2050;
- A long term planned policy to support RES does not drive up wholesale prices relative to other scenarios with less ambitious RES policies, and actually reduces them after 2045;
- The macroeconomic analysis shows that the high absolute increase in wholesale prices (between 214% and 265%) translates to higher burden on households, with electricity expenditure relative to household income going from 4% to 8% by 2050 in most scenarios;
- The cost of stranded investments are similar across all scenarios, ranging from 872 mEUR to 984 mEUR, representing significant costs to the consumers;
- The 'decarbonisation' and 'delayed' scenarios enable Bulgaria to significantly reduce its reliance on imported fossil fuels over the long term, especially natural gas;
- Decarbonisation will require significantly more aggregated investment, from approximately 8.5 bn EUR to 15-18 bn EUR over the 35-year period:
  - This private investment will have a positive effect on GDP growth by about 2% on average with a small positive effect on employment over the assessed period;
  - Increased investment needs are counterbalanced by reduced fossil fuel imports resulting in a moderate net effect on the fiscal balance and current account;
  - External debt falls slightly in the 'decarbonisation' scenario while increasing by 3% of GDP in the other two scenarios over the long term.

6.1 Main electricity system trends

In Bulgaria approximately 45% of current fossil fuel generation capacity, or more than 2600 MW, is expected to be decommissioned by the end of 2030, and 97% of current generation capacity will be decommissioned by 2050. This provides both a challenge to ensure a policy framework which will result in the necessary new investment, but also an opportunity to shape the electricity sector over the long term without being constrained by the current capacity mix.

Whether Bulgaria pursues an active policy supporting renewable electricity generation, fossil fuel generation capacity will decline precipitously due to the rising carbon price. Coal and lignite are phased out under all scenarios by 2050, but the decline in the share of these fuels begins much earlier: as low as 14% already in 2040 from the current 50% level.

With ambitious decarbonisation targets and corresponding RES support schemes, Bulgaria can achieve an electricity mix with close to 53-54% renewable generation of mostly wind, hydro and some solar 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 approximately 32% in 2050. This represents a significant increase compared to current levels.

The high penetration of RES in all scenarios suggests that a robust no-regret action for Bulgaria energy policy is to focus on enabling RES integration. This involves:

- investing in transmission and distribution networks to enable the integration of new RES capacity in the domestic and regional electricity system,
- 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,
- reducing the administrative and financial burden for the installation of RES capacities in decentralised community systems

Natural gas will remain a relevant fuel source over the coming decades, increasing in all scenarios initially. However, the role of natural gas is transitory in a scenario with a decarbonisation target, playing only a minor role by 2050. In the 'decarbonisation' scenario new gas capacity is mainly installed to replace outgoing capacity, but there is no need for a very significant capacity increase to bridge the transition from fossil fuel to renewable based electricity mix; higher gas based generation is realised with higher utilisation rates. Under the 'no target' scenario gas remains relevant in 2050 with 13% share in production, but gas based generation peaks in 2040. The 'delayed' scenario presents a pathway where gas based generation only increases slightly before disappearing by 2050.

The role for gas under the 'decarbonisation' and 'delayed' scenarios, is limited. If significant investments are made in gas based generation and infrastructure (as well as in coal based generation) it can result in stranded assets. Bulgaria presents a unique case in this regard, as stranded cost are almost equal in all scenarios. The significantly lower level of gas use in the 'decarbonisation' and 'delayed' scenarios compared to the 'no target' scenario poses a serious question for policy makers – to what extent investments in the gas sector should be stimulated in a future energy sector with serious decarbonisation targets.

Delayed action in the rollout of renewables is feasible but carries a significant disadvantage compared with a long term planned effort. Assuming delayed action, **the disproportionate push towards the end of the modelled period to meet the CO_2 emission reduction target requires significant increases in RES support.**

6.2 Security of supply

In all scenarios, Bulgaria becomes a net importer of electricity between 2030 and 2040. By 2050, 22% of consumption will be covered by imports in the 'no target' scenario and 12% in the 'decarbonisation' scenario. Although its system adequacy remains favourable, the generation adequacy indicator reaches close to zero levels after 2030. In the 'delayed' scenario generation adequacy values even become negative, showing Bulgaria's dependency on imports.

In order to address the intermittency of the significant share of the installed generation capacity, Bulgaria could work on the no regret measures discussed above to enable a high share of RES penetration without compromising security of supply, involving demand side measures, increased network connections and storage solutions.

The 'decarbonisation' and 'no target' scenarios show that Bulgaria might significantly increase its reliance on imported fossil fuels, mostly natural gas, in the modelled period, and this trend only changes after 2040.

The network modelling results suggest that Bulgaria would have to invest in the transmission network and cross-border capacity. Investment is needed in the Bulgarian transmission network – estimated to be in the range of 92 mEUR in addition to the realisation of investments contained in ENTSO-E TYNDP 2016.

6.3 Sustainability

Bulgaria has significant solar potential relative to the EU average, especially in solar, relative to the EU average, allowing it to contribute to 2050 emission reduction targets. In Bulgaria CO_2 emissions in the electricity sector fall by close to 99% in the 'delayed' and 97% in the 'decarbonisation' scenarios compared with the 94% target set for the EU28+Western Balkans region as a whole. The high CO_2 emission reduction potential is supplemented by the existing nuclear capacity.

The RES potential can be realised with policies eliminating barriers to RES investment, and **a no-regret de-risking policy addressing the high cost of capital.** This would allow for cost-efficient renewable energy investment.

6.4 Affordability and competitiveness

Decarbonising the electricity sector does not drive up wholesale electricity prices compared to a scenario with no reduction target. 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, serving as the marginal production for 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 in the decarbonisation scenarios when wholesale electricity prices 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 the price of carbon and the price of natural gas, both of which increase significantly by 2050. While higher wholesale prices will reach end consumers, it is an important signal for attracting investment to replace retiring capacity. The macroeconomic analysis shows that the high absolute increase in wholesale prices (between 214% and 265%) translates to higher burden on households, with electricity expenditure relative to household income going from 4% to 8% by 2050 in most scenarios. **However, this is not because of higher RES deployment, as the 'no target' scenario with no further RES support presents similar results.**

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 boosts GDP and has a small but positive impact on employment. At the same time, the fiscal and external balance remains stable compared with the 'baseline' scenario in spite of increasing electricity and gas imports. A big policy challenge for the Bulgarian government is to prevent increasing energy poverty rates with increasing electricity expenditure in the lower income level groups. This requires new policy approaches and instruments, and not administrative retail tariff setting or other market distorting interventions.

Although not modelled with sufficient details, **wholesale electricity price volatility is also expected to increase,** ceteris paribus, in a world with a high share of intermittent renewables. **Demand and supply side measures can reduce this price volatility,** but governments will need to determine the acceptable level in relation to the costs of supply and demand side measures.

High initial investment requirements for RES technologies are extremely sensitive to the cost of capital, which is high in Bulgaria compared with Western European member states. Although much of the value of the cost of capital depends on the country risk profile linked to the general 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 because they minimise system cost and consumer expenditures.**

Electricity sector decarbonisation is driven by continued RES support during the entire period until 2050 under the decarbonisation target scenarios. However, the need for support is capped by increasing electricity wholesale prices which incentivise significant RES investment even without support. In the case of Bulgaria RES support can be covered by EU ETS revenues in most scenarios, lowering the burden to consumers. **Long term evidence based policy planning** can provide investors with the necessary stability to ensure that sufficient renewable investments will take place.

7 | References

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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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	502	902	1 302	1 302	1 240
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 063	2 934	2 820	2 831	3 014	3 184
	Wind		700	700	690	214	11	756	1 515	2 798
	Solar		1 064	1 064	1 064	1 064	530	748	1 187	1 845
	Other RES		62	132	167	211	256	366	542	576
Gross consumption, GWh			34 337	35 518	36 158	36 802	36 997	37 863	38 987	41 334
Net electricity generation, GWh	Total		42 968	46 661	41 002	38 626	35 702	36 388	36 879	32 145
	Coal and lignite		21 913	25 356	19 230	14 142	9 159	5 356	2 959	210
	Natural gas		930	987	1 333	4 608	7 335	9 531	9 403	4 218
	Nuclear		14 303	14 303	14 303	14 303	14 303	14 303	14 303	14 303
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 172	3 172	3 198	3 444	3 722	3 977
	Wind		1 088	1 088	1 072	333	17	1 175	2 354	4 347
	Solar		1 232	1 232	1 232	1 232	614	866	1 375	2 137
	Other RES		330	524	659	836	1 077	1 712	2 763	2 953
Net import, GWh	Total		-8 631	-11 143	-4 843	-1 824	1 295	1 475	2 107	9 189
	GR		-3 572	-1 344	332	-1 455	3 500	-7 247	-6 553	604
	MK		-1 420	-909	197	-161	-105	-176	178	-150
	RO		-1 298	-7 031	-4 295	523	2 552	7 264	6 514	6 637
	RS		-2 341	-1 859	-1 078	-731	-4 652	1 635	1 969	2 097
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-25.1%	-31.4%	-13.4%	-5.0%	3.5%	3.9%	5.4%	22.2%
RES-E share (RES-E production/gross consumption, %)			17.0%	16.9%	17.0%	15.1%	13.3%	19.0%	26.2%	32.5%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	53%
	Wind		na	na	na	na	na	na	na	28%
	Solar		na	na	na	na	na	na	na	19%
Utilisation rates of conventional power production, %	Coal and lignite		46.0%	50.6%	55.5%	49.1%	36.5%	64.5%	35.6%	4.6%
	Natural gas		25.2%	21.5%	30.1%	58.1%	64.1%	65.4%	77.9%	38.8%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	81.6%	81.6%	81.6%
Natural gas consumption of power generation, TWh			2.29	2.39	2.99	8.65	13.33	16.95	16.20	7.23
Security of supply	Generation adequacy margin		52%	58%	27%	20%	18%	1%	5%	2%
	System adequacy margin		67%	96%	64%	60%	65%	49%	72%	64%
CO_2 emission	Emission, Mt CO_2		25.3	28.8	21.8	17.4	12.6	8.9	6.3	1.7
	CO_2 emission reduction compared to 1990, %		-6.8%	-21.6%	7.9%	26.7%	47.0%	62.3%	73.5%	93.0%
Spreads	Clean dark spread, €(2015)/MWh		15.8	14.9	18.9	14.8	13.5	13.9	6.6	-13.6
	Clean spark spread, €(2015)/MWh		-2.8	-3.7	-0.7	-1.7	-1.5	-2.7	-2.7	-9.6
Price impacts	Electricity wholesale price, €(2015)/MWh		34.2	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	7.8	2.5	0.7	0.4	0.0	0.0	0.0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.3	12.2	13.6	15.8	14.3	11.8	11.1	3.5
Investment cost, m€/5 year period	Coal and lignite		na	1 306	0	0	0	0	0	0
	Natural gas		na	94	0	367	367	365	0	0
	Total Fossil		na	1 400	0	367	367	365	0	0
	Total RES-E		na	106	20	38	236	1 579	1 827	2 198
	Total		na	1 506	20	405	602	1 945	1 827	2 198
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	102	102	102	102	40
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 231	3 138	3 047	3 113	3 301	3 553
	Wind		700	700	1 260	793	640	2 187	4 073	6 429
	Solar		1 064	1 064	1 359	1 359	825	1 338	2 139	3 250
	Other RES		62	133	237	313	383	572	646	703
Gross consumption, GWh			34 337	35 518	36 212	36 738	37 008	37 791	38 873	40 782
Net electricity generation, GWh	Total		42 967	46 639	42 126	35 467	30 730	32 096	32 890	35 145
	Coal and lignite		21 912	25 333	18 738	12 151	7 874	4 814	1 811	331
	Natural gas		930	986	1 105	1 261	1 191	1 148	321	0
	Nuclear		14 303	14 303	14 303	14 303	14 303	14 303	14 263	12 686
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 470	3 533	3 599	3 944	4 230	4 631
	Wind		1 088	1 088	1 957	1 232	994	3 398	6 329	9 988
	Solar		1 232	1 232	1 574	1 574	955	1 549	2 477	3 763
	Other RES		330	526	979	1 414	1 813	2 940	3 460	3 747
Net import, GWh	Total		-8 630	-11 122	-5 914	1 271	6 277	5 695	5 983	5 638
	GR		-3 584	-1 461	-2 054	-2 803	53	-5 353	1 025	2 025
	MK		-1 497	-1 006	109	126	327	171	150	183
	RO		-1 427	-6 826	-3 052	4 067	4 101	7 038	2 896	880
	RS		-2 122	-1 828	-918	-120	1 795	3 838	1 911	2 549
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-25.1%	-31.3%	-16.3%	3.5%	17.0%	15.1%	15.4%	13.8%
RES-E share (RES-E production/gross consumption, %)			17.0%	16.9%	22.0%	21.1%	19.9%	31.3%	42.4%	54.3%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	63%
	Wind		na	na	na	na	na	na	na	64%
	Solar		na	na	na	na	na	na	na	33%
Utilisation rates of conventional power production, %	Coal and lignite		46.0%	50.5%	54.1%	42.2%	31.4%	58.0%	21.8%	7.3%
	Natural gas		25.2%	21.5%	24.9%	28.5%	26.9%	28.2%	20.6%	0.0%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	81.6%	81.4%	72.4%
Natural gas consumption of power generation, TWh			2.29	2.39	2.57	2.85	2.73	2.59	0.63	–
Security of supply	Generation adequacy margin		52%	58%	31%	18%	11%	-9%	-4%	-3%
	System adequacy margin		67%	96%	68%	59%	58%	39%	63%	61%
CO_2 emission	Emission, Mt CO_2		25.3	28.8	21.2	13.9	9.0	5.5	2.0	0.3
	CO_2 emission reduction compared to 1990, %		-6.8%	-21.5%	10.3%	41.3%	62.1%	76.9%	91.6%	98.6%
Spreads	Clean dark spread, €(2015)/MWh		15.8	14.9	16.7	13.5	12.1	17.2	3.7	-30.9
	Clean spark spread, €(2015)/MWh		-2.8	-3.7	-2.9	-3.0	-3.0	0.6	-5.6	-26.9
Price impacts	Electricity wholesale price, €(2015)/MWh		34.2	41.0	50.7	58.9	67.0	80.9	87.6	73.2
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	7.8	4.2	1.0	0.9	1.9	2.9	18.4
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.3	12.2	13.2	12.7	10.2	7.2	3.5	0.7
Investment cost, m€/5 year period	Coal and lignite		na	1 306	0	0	0	0	0	0
	Natural gas		na	94	0	0	0	0	0	0
	Total Fossil		na	1 400	0	0	0	0	0	0
	Total RES-E		na	106	1 348	188	398	3 104	3 926	4 164
	Total		na	1 506	1 348	188	398	3 104	3 926	4 164
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	102	502	502	502	440
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 314	3 380	3 418	3 436	3 605	3 728
	Wind		700	700	1 286	1 498	1 986	2 567	3 455	4 803
	Solar		1 064	1 064	1 359	1 920	2 232	2 806	4 006	4 954
	Other RES		62	133	258	448	539	636	635	713
Gross consumption, GWh			34 337	35 506	36 195	36 656	36 977	37 751	38 769	40 770
Net electricity generation, GWh	Total		42 967	47 282	43 038	39 202	37 481	36 999	36 005	35 726
	Coal and lignite		21 912	25 826	19 100	12 829	7 329	4 722	1 996	543
	Natural gas		930	1 135	1 355	1 356	3 373	3 036	2 129	682
	Nuclear		14 303	14 303	14 303	14 303	14 303	14 303	13 923	12 674
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 617	3 962	4 256	4 515	4 769	4 940
	Wind		1 088	1 088	1 997	2 327	3 086	3 989	5 368	7 461
	Solar		1 232	1 232	1 574	2 225	2 585	3 250	4 640	5 736
	Other RES		330	526	1 091	2 201	2 551	3 185	3 180	3 690
Net import, GWh	Total		-8 630	-11 776	-6 843	-2 546	-504	752	2 764	5 043
	GR		-3 584	-927	400	-489	338	-4 353	1 252	4 595
	MK		-1 497	-1 188	-800	-610	-634	-467	-330	-78
	RO		-1 427	-7 276	-4 713	-359	2 765	5 447	3 031	289
	RS		-2 122	-2 385	-1 731	-1 088	-2 973	125	-1 189	236
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-25.1%	-33.2%	-18.9%	-6.9%	-1.4%	2.0%	7.1%	12.4%
RES-E share (RES-E production/gross consumption, %)			17.0%	16.9%	22.9%	29.2%	33.7%	39.6%	46.3%	53.5%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	67%
	Wind		na	na	na	na	na	na	na	48%
	Solar		na	na	na	na	na	na	na	50%
Utilisation rates of conventional power production, %	Coal and lignite		46.0%	51.5%	55.1%	44.6%	29.2%	56.9%	24.0%	12.0%
	Natural gas		25.2%	24.8%	30.6%	30.6%	42.5%	40.1%	42.0%	17.7%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	81.6%	79.5%	72.3%
Natural gas consumption of power generation, TWh			2.29	2.66	3.03	3.03	6.49	5.85	3.74	1.18
Security of supply	Generation adequacy margin		52%	58%	32%	24%	27%	3%	5%	3%
	System adequacy margin		67%	96%	69%	65%	75%	52%	73%	63%
CO_2 emission	Emission, Mt CO_2		25.3	29.3	21.7	14.7	9.1	6.0	2.8	0.8
	CO_2 emission reduction compared to 1990, %		-6.8%	-23.9%	8.4%	37.8%	61.4%	74.6%	88.2%	96.7%
Spreads	Clean dark spread, €(2015)/MWh		15.8	15.9	18.5	14.1	11.7	17.9	3.2	-29.5
	Clean spark spread, €(2015)/MWh		-2.8	-2.6	-1.2	-2.4	-3.3	1.3	-6.0	-25.5
Price impacts	Electricity wholesale price, €(2015)/MWh		34.2	42.0	52.4	59.5	66.7	81.7	87.1	74.6
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	7.8	3.7	3.0	3.0	1.7	0.2	1.4
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.3	12.4	13.5	13.5	10.4	8.0	5.0	1.7
Investment cost, m€/5 year period	Coal and lignite		na	1 306.1	0.0	0.0	0.0	0.0	0.0	0.0
	Natural gas		na	94.1	0.0	0.0	366.3	0.0	0.0	0.0
	Total Fossil		na	1 400.3	0.0	0.0	366.3	0.0	0.0	0.0
	Total RES-E		na	106	2 040	2 059	2 089	2 419	3 802	3 970
	Total		na	1 506	2 040	2 059	2 456	2 419	3 802	3 970
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	102	502	502	502	440
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 314	3 380	3 418	3 460	3 658	3 845
	Wind		700	700	1 371	2 053	2 776	3 796	5 577	7 282
	Solar		1 064	1 064	1 452	2 066	2 599	3 463	4 327	5 693
	Other RES		62	133	310	500	634	665	706	711
Gross consumption, GWh			34 369	35 545	36 271	36 769	37 116	37 858	38 980	41 064
Net electricity generation, GWh	Total		43 297	48 056	43 728	42 776	44 312	39 141	39 972	38 964
	Coal and lignite		22 214	26 565	19 311	15 338	12 791	5 051	4 285	1 991
	Natural gas		958	1 170	1 396	1 167	2 467	2 411	1 137	463
	Nuclear		14 303	14 303	14 303	14 303	14 298	13 825	12 309	10 013
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 617	3 962	4 256	4 557	4 854	5 100
	Wind		1 088	1 088	2 131	3 189	4 313	5 898	8 656	11 226
	Solar		1 232	1 232	1 682	2 393	3 011	4 012	4 989	6 421
	Other RES		330	526	1 289	2 425	3 177	3 388	3 743	3 750
Net import, GWh	Total		-8 928	-12 511	-7 457	-6 007	-7 196	-1 283	-993	2 101
	GR		-3 423	-2 921	-1 158	-4 909	-5 510	-6 824	-2 160	-125
	MK		-1 433	-1 495	-933	-766	-296	-456	-190	59
	RO		-1 534	-5 510	-3 966	965	1 722	5 051	1 106	1 160
	RS		-2 538	-2 585	-1 400	-1 297	-3 113	946	252	1 007
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-26.0%	-35.2%	-20.6%	-16.3%	-19.4%	-3.4%	-2.5%	5.1%
RES-E share (RES-E production/gross consumption, %)			16.9%	16.9%	24.0%	32.6%	39.8%	47.2%	57.1%	64.5%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	69.9%
	Wind		na	na	na	na	na	na	na	72.0%
	Solar		na	na	na	na	na	na	na	57.8%
Utilisation rates of conventional power production, %	Coal and lignite		46.7%	53.0%	55.7%	53.3%	50.9%	60.8%	51.6%	43.9%
	Natural gas		25.9%	25.5%	31.5%	26.3%	31.1%	31.9%	22.5%	12.0%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	78.9%	70.3%	57.1%
Natural gas consumption of power generation, TWh			2.3	2.7	3.1	2.7	4.9	4.8	2.0	0.8
Security of supply	Generation adequacy margin		52%	58%	33%	27%	30%	7%	12%	10%
	System adequacy margin		67%	96%	70%	67%	78%	55%	80%	71%
CO_2 emission	Emission, Mt CO_2		25.6	30.1	21.9	17.7	15.0	6.2	4.8	2.2
	CO_2 emission reduction compared to 1990, %		-8.2%	-27.2%	7.5%	25.5%	36.6%	73.9%	79.6%	90.9%
Spreads	Clean dark spread, €(2015)/MWh		12.5	12.1	12.5	3.2	-1.4	7.8	-15.3	-54.2
	Clean spark spread, €(2015)/MWh		-6.1	-6.5	-7.1	-13.2	-16.4	-8.8	-24.5	-50.2
Price impacts	Electricity wholesale price, €(2015)/MWh		30.9	38.2	46.5	48.7	53.5	71.6	68.6	49.9
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	8.1	8.5	8.9	12.8	13.0	15.1	29.5
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.4	12.7	13.6	16.1	17.0	8.2	8.5	4.6
Investment cost, m€/5 year period	Coal and lignite		na	1 306	0	0	0	0	0	0
	Natural gas		na	94	0	0	366	0	0	0
	Total Fossil		na	1 400	0	0	366	0	0	0
	Total RES-E		na	106	1 959	2 514	2 662	2 596	4 004	4 587
	Total		na	1 506	1 959	2 514	3 028	2 596	4 004	4 587
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	102	102	102	102	40
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 264	3 248	3 264	3 168	3 355	3 486
	Wind		700	700	1 277	1 003	1 303	1 588	2 895	3 524
	Solar		1 064	1 064	1 359	1 457	1 264	1 867	2 896	3 993
	Other RES		62	133	241	339	426	517	576	587
Gross consumption, GWh			34 337	35 163	35 405	35 485	35 282	35 490	36 109	37 462
Net electricity generation, GWh	Total		42 968	47 112	42 840	38 087	34 625	31 888	31 325	31 120
	Coal and lignite		21 913	25 691	19 110	13 769	9 373	5 042	1 982	647
	Natural gas		930	1 100	1 346	1 455	1 362	1 327	316	0
	Nuclear		14 303	14 303	14 303	14 303	14 303	14 303	13 892	12 864
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 529	3 727	3 984	4 041	4 326	4 511
	Wind		1 088	1 088	1 984	1 559	2 024	2 468	4 498	5 475
	Solar		1 232	1 232	1 574	1 688	1 464	2 162	3 354	4 625
	Other RES		330	526	994	1 586	2 115	2 545	2 955	2 997
Net import, GWh	Total		-8 631	-11 949	-7 435	-2 602	657	3 603	4 784	6 343
	GR		-3 547	-1 004	304	142	1 664	-2 081	2 848	5 284
	MK		-1 518	-1 294	-835	-712	-418	-606	-315	-277
	RO		-1 356	-7 029	-5 155	-1 137	2 054	6 073	2 817	-71
	RS		-2 209	-2 622	-1 750	-895	-2 643	217	-566	1 407
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-25.1%	-34.0%	-21.0%	-7.3%	1.9%	10.2%	13.2%	16.9%
RES-E share (RES-E production/gross consumption, %)			17.0%	17.1%	22.8%	24.1%	27.2%	31.6%	41.9%	47.0%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	61.1%
	Wind		na	na	na	na	na	na	na	34.9%
	Solar		na	na	na	na	na	na	na	40.5%
Utilisation rates of conventional power production, %	Coal and lignite		46.0%	51.2%	55.1%	47.8%	37.3%	60.7%	23.9%	14.2%
	Natural gas		25.2%	24.0%	30.4%	32.9%	30.8%	32.6%	20.3%	0.0%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	81.6%	79.3%	73.4%
Natural gas consumption of power generation, TWh			2.3	2.6	3.0	3.2	3.0	2.9	0.6	0.0
Security of supply	Generation adequacy margin		52%	59%	34%	23%	26%	0%	5%	1%
	System adequacy margin		67%	98%	71%	65%	75%	51%	77%	66%
CO_2 emission	Emission, Mt CO_2		25.3	29.2	21.7	15.8	10.7	5.8	2.2	0.7
	CO_2 emission reduction compared to 1990, %		-6.8%	-23.3%	8.4%	33.1%	54.6%	75.6%	90.9%	97.3%
Spreads	Clean dark spread, €(2015)/MWh		15.8	15.6	18.4	14.6	15.3	25.2	0.2	-28.7
	Clean spark spread, €(2015)/MWh		-2.8	-2.9	-1.2	-1.8	0.2	8.6	-9.1	-24.7
Price impacts	Electricity wholesale price, €(2015)/MWh		34.2	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	7.8	5.0	1.8	1.8	0.3	0.0	0.0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.3	12.5	13.8	14.9	12.8	8.2	4.1	1.5
Investment cost, m€/5 year period	Coal and lignite		na	1 306.1	0.0	0.0	0.0	0.0	0.0	0.0
	Natural gas		na	94.1	0.0	0.0	0.0	0.0	0.0	0.0
	Total Fossil		na	1 400	0	0	0	0	0	0
	Total RES-E		na	106	1 479	633	1 345	1 266	3 386	2 026
	Total		na	1 506	1 479	633	1 345	1 266	3 386	2 026
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	102	502	502	502	440
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 314	3 380	3 418	3 460	3 658	3 848
	Wind		700	700	1 371	2 053	2 645	3 764	5 292	7 391
	Solar		1 064	1 064	1 452	2 066	2 599	3 567	4 536	5 585
	Other RES		62	133	310	504	642	636	712	738
Gross consumption, GWh			34 337	35 851	37 014	37 946	38 757	40 082	41 715	44 389
Net electricity generation, GWh	Total		42 968	47 442	43 514	40 167	39 000	39 130	38 720	40 180
	Coal and lignite		21 913	25 948	19 092	12 523	6 940	4 355	1 825	708
	Natural gas		930	1 174	1 398	1 358	3 172	2 844	1 895	729
	Nuclear		14 303	14 303	14 303	14 303	14 303	14 209	12 907	11 906
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 617	3 962	4 256	4 557	4 861	5 132
	Wind		1 088	1 088	2 131	3 189	4 110	5 848	8 223	11 444
	Solar		1 232	1 232	1 682	2 393	3 011	4 131	5 255	6 391
	Other RES		330	526	1 291	2 439	3 209	3 186	3 754	3 871
Net import, GWh	Total		-8 631	-11 591	-6 500	-2 221	-243	952	2 995	4 209
	GR		-3 572	-721	650	-343	-1 145	-5 894	-1 399	1 619
	MK		-1 463	-1 352	-699	-703	-479	-514	4	-22
	RO		-1 374	-7 313	-4 654	231	3 054	4 755	2 762	1 352
	RS		-2 221	-2 206	-1 797	-1 406	-1 672	2 605	1 627	1 259
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-25.1%	-32.3%	-17.6%	-5.9%	-0.6%	2.4%	7.2%	9.5%
RES-E share (RES-E production/gross consumption, %)			17.0%	16.8%	23.6%	31.6%	37.6%	44.2%	53.0%	60.5%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	70.0%
	Wind		na	na	na	na	na	na	na	73.1%
	Solar		na	na	na	na	na	na	na	56.7%
Utilisation rates of conventional power production, %	Coal and lignite		46.0%	51.8%	55.1%	43.5%	27.6%	52.4%	22.0%	15.6%
	Natural gas		25.2%	25.6%	31.6%	30.7%	40.0%	37.6%	37.4%	18.9%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	81.1%	73.7%	68.0%
Natural gas consumption of power generation, TWh			2.3	2.7	3.1	3.0	6.1	5.5	3.3	1.3
Security of supply	Generation adequacy margin		52%	57%	31%	23%	25%	2%	5%	4%
	System adequacy margin		67%	95%	67%	63%	72%	48%	70%	61%
CO_2 emission	Emission, Mt CO_2		25.3	29.5	21.7	14.4	8.6	5.6	2.5	1.0
	CO_2 emission reduction compared to 1990, %		-6.8%	-24.5%	8.4%	39.3%	63.5%	76.4%	89.2%	95.9%
Spreads	Clean dark spread, €(2015)/MWh		24.9	32.2	42.6	49.6	56.2	69.4	71.9	61.5
	Clean spark spread, €(2015)/MWh		0.7	3.7	8.2	11.0	13.4	19.8	17.1	7.4
Price impacts	Electricity wholesale price, €(2015)/MWh		34.2	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	7.8	8.2	7.0	8.6	7.5	7.1	17.0
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.3	12.3	13.2	12.7	9.4	7.0	4.2	1.9
Investment cost, m€/5 year period	Coal and lignite		na	94.1	0.0	0.0	366.3	0.0	0.0	0.0
	Natural gas		na	1 306.1	0.0	0.0	0.0	0.0	0.0	0.0
	Total Fossil		na	1 400	0	0	366	0	0	0
	Total RES-E		na	106	1 961	2 535	2 519	2 650	3 866	4 921
	Total		na	1 506	1 961	2 535	2 886	2 650	3 866	4 921
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	5 435	5 223	3 456	2 786	2 366	448	448	18
		New	0	500	500	500	500	500	500	500
	Natural gas	Existing	422	422	404	404	404	362	76	0
		New	0	102	102	102	502	502	502	440
	Nuclear	Existing	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000
		New	0	0	0	0	0	0	0	0
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 191	3 191	3 323	3 406	3 456	3 522	3 725	4 017
	Wind		700	700	1 260	1 313	1 422	1 976	3 073	3 991
	Solar		1 064	1 064	1 411	1 999	2 669	3 905	5 510	7 038
	Other RES		62	133	301	487	635	655	719	870
Gross consumption, GWh			34 337	35 506	36 200	36 655	36 976	37 751	38 787	40 776
Net electricity generation, GWh	Total		42 974	47 323	43 250	39 323	37 975	37 733	37 551	38 048
	Coal and lignite		21 919	25 859	19 099	12 937	7 432	4 715	2 091	660
	Natural gas		930	1 143	1 366	1 370	3 436	3 105	2 151	751
	Nuclear		14 303	14 303	14 303	14 303	14 303	14 300	13 372	12 551
	HFO/LFO		0	0	0	0	0	0	0	0
	Hydro		3 172	3 172	3 633	4 008	4 322	4 667	4 981	5 436
	Wind		1 088	1 088	1 958	2 039	2 209	3 071	4 774	6 187
	Solar		1 232	1 232	1 635	2 316	3 092	4 523	6 382	8 083
	Other RES		330	526	1 256	2 351	3 181	3 353	3 799	4 380
Net import, GWh	Total		-8 636	-11 817	-7 051	-2 668	-998	17	1 237	2 729
	GR		-3 524	-625	475	672	1 038	-3 736	942	2 201
	MK		-1 447	-1 340	-719	-796	-345	-475	-470	-169
	RO		-1 400	-7 930	-4 809	-893	1 443	3 864	2 693	1 758
	RS		-2 266	-1 922	-1 997	-1 650	-3 134	363	-1 928	-1 062
	TR		0	0	0	0	0	0	0	0
Net import ratio, %			-25.2%	-33.3%	-19.5%	-7.3%	-2.7%	0.0%	3.2%	6.7%
RES-E share (RES-E production/gross consumption, %)			17.0%	16.9%	23.4%	29.2%	34.6%	41.4%	51.4%	59.1%
Utilisation rates of RES-E technical potential, %	Hydro		na	na	na	na	na	na	na	75.1%
	Wind		na	na	na	na	na	na	na	39.5%
	Solar		na	na	na	na	na	na	na	71.5%
Utilisation rates of conventional power production, %	Coal and lignite		46.0%	51.6%	55.1%	44.9%	29.6%	56.8%	25.2%	14.5%
	Natural gas		25.2%	24.9%	30.8%	30.9%	43.3%	41.0%	42.5%	19.5%
	Nuclear		81.6%	81.6%	81.6%	81.6%	81.6%	81.6%	76.3%	71.6%
Natural gas consumption of power generation, TWh			2.3	2.7	3.0	3.1	6.6	6.0	3.8	1.3
Security of supply	Generation adequacy margin		52%	58%	33%	25%	27%	3%	7%	6%
	System adequacy margin		67%	96%	70%	66%	75%	52%	75%	66%
CO_2 emission	Emission, Mt CO_2		25.3	29.4	21.7	14.9	9.3	6.0	2.9	0.9
	CO_2 emission reduction compared to 1990, %		-6.8%	-24.1%	8.4%	37.3%	60.9%	74.5%	87.7%	96.1%
Spreads	Clean dark spread, €(2015)/MWh		25.0	31.9	42.4	49.8	56.4	71.1	74.9	63.8
	Clean spark spread, €(2015)/MWh		0.7	3.5	7.9	11.2	13.7	21.5	20.2	9.7
Price impacts	Electricity wholesale price, €(2015)/MWh		34.3	42.1	52.5	59.6	66.8	81.7	85.6	74.4
	Total RES-E support/gross consumption, €(2015)/MWh, five year average		na	7.6	7.7	4.6	5.9	5.9	8.0	63.9
	Revenue from CO_2 auction/gross consumption, €(2015)/MWh		6.3	12.4	13.5	13.6	10.5	8.0	5.2	2.0
Investment cost, m€/5 year period	Coal and lignite		na	94.1	0.0	0.0	0.0	0.0	0.0	0.0
	Natural gas		na	1 306.1	0.0	0.0	0.0	0.0	0.0	0.0
	Total Fossil		na	1 400	0	0	0	0	0	0
	Total RES-E		na	106	1 803	1 676	2 089	2 318	3 648	3 499
	Total		na	1 506	1 803	1 676	2 089	2 318	3 648	3 499
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		16.79	19.32	22.27	24.20	26.53	30.13	32.72	32.37
	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	168	189	619
Solid biomass	222	216	2 700
Biowaste	175	162	162
Geothermal ele.	528	830	547
Hydro large-scale	512	980	922
Hydro small-scale	17	226	489
Central PV	458	1 011	1 478
Decentralised PV	672	1 287	2 669
CSP	0	0	0
Wind onshore	3 252	8 333	6 899
Wind offshore	0	0	0
RES-E total	6 004	13 234	16 485

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	**1 451**	**466**	**142**	**77**	**9**	**–**	**–**	**2 144**
Central PV	580	107	–	–	–	–	–	687
Decentralised PV	353	105	–	–	–	–	–	458
Wind onshore	325	62	–	–	–	–	–	386
Delayed	**1 451**	**786**	**187**	**174**	**382**	**582**	**3 909**	**7 472**
Central PV	580	134	3	7	36	54	345	1 159
Decentralised PV	353	125	2	6	29	46	340	902
Wind onshore	325	221	20	43	193	328	2 341	3 470
Decarbon	**1 448**	**702**	**568**	**575**	**329**	**47**	**298**	**3 967**
Central PV	580	138	55	82	85	29	170	1 138
Decentralised PV	353	126	46	69	48	4	70	716
Wind onshore	323	245	322	346	188	14	58	1 495

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

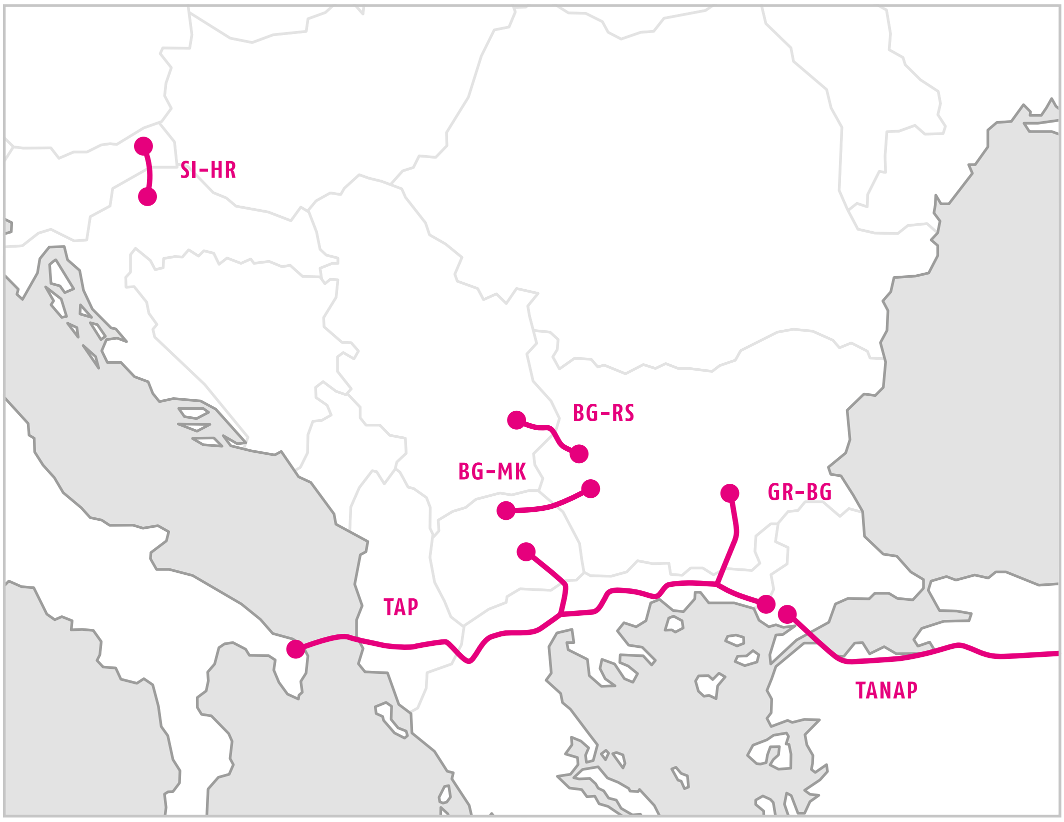
Infrastructure (table for the whole region)

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
BG	RO	2020	1 000	1 200
GR	BG	2021	0	650
GR	BG	2030	250	450
RS	BG	2034	50	200
RS	BG	2034	400	1 500
BG	GR	2045	1 000	1 000

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 Maritsa East 2 A-B	320	1966	2021	lignite	thermal	no	yes	yes	yes
TPP Maritsa East 2 C	212	1967	2016	lignite	thermal	no	yes	yes	yes
TPP Maritsa East 2 D	212	1969	2024	lignite	thermal	no	yes	yes	yes
Lukoil_Nefto	257	1985	2040	lignite	thermal	no	yes	yes	yes
TPP Varna B	210	1969	2015	coal	thermal	no	yes	yes	yes
TPP Plovdiv A	105	1970	2025	coal	thermal	no	yes	yes	yes
TPP Brikel	200	1970	2025	coal	thermal	no	yes	yes	yes
TPP Varna C	210	1970	2015	coal	thermal	no	yes	yes	yes
TPP Bobov dol B	210	1974	2031	lignite	thermal	no	yes	yes	yes
TPP Bobov dol C	210	1975	2031	lignite	thermal	no	yes	yes	yes
TPP Varna D	210	1977	2015	coal	thermal	no	yes	yes	yes
TPP Varna E-F	420	1979	2015	coal	thermal	no	yes	yes	yes
TPP Shouumen	18	1981	2021	natural gas	OCGT	no	yes	yes	yes
TPP Maritsa East 3 A-D	908	1981	2036	lignite	thermal	no	yes	yes	yes
TPP Deven	132	1984	2039	coal	thermal	no	yes	yes	yes
TPP Rousse E-F	180	1985	2040	coal	thermal	no	yes	yes	yes
TPP Maritsa East 2 E-F	430	1985	2040	lignite	thermal	no	yes	yes	yes
NPP Kozloduy E	1000	1987	2060	nuclear	nuclear	no	yes	yes	yes
NPP Kozloduy F	1000	1991	2061	nuclear	nuclear	no	yes	yes	yes
TPP Maritsa East 2 G-H	430	1995	2050	lignite	thermal	no	yes	yes	yes
TPP Plovdiv C	25	1996	2036	natural gas	OCGT	no	yes	yes	yes
Other TPP DH	16.6	2000	2040	natural gas	OCGT	no	yes	yes	yes
TPP Gabrovo	18	2000	2055	coal	thermal	no	yes	yes	yes
TPP Plovdiv B	30	2001	2041	natural gas	OCGT	no	yes	yes	yes
TPP Pleven	36	2007	2047	natural gas	OCGT	no	yes	yes	yes
Plovdiv Sever	50	2011	2041	natural gas	CCGT	no	yes	yes	yes
TPP Sofia	40	2014	2044	natural gas	CCGT	no	no	no	no
CHP TPP Sofia	40	2013	2043	natural gas	CCGT	no	yes	yes	yes
CHP TPP Sofia-Istok	156	1964	2043	natural gas	thermal	no	yes	yes	yes
CHP TPP Pernik	105	1951		coal	thermal	no	yes	yes	yes
CHP TPP Sliven	30	1969		coal	thermal	no	yes	yes	yes
CHP TPP Vladislav Varnenchik	11			coal	thermal	no	yes	yes	yes
Maritsa Iztok unit 1	335	2011	2026	lignite	thermal	no	yes	yes	yes
Maritsa Iztok unit 2	335	2011	2026	lignite	thermal	no	yes	yes	yes
Maritsa Iztok 3 unit 1	225	2009	2024	lignite	thermal	no	yes	yes	yes
Maritsa Iztok 3 unit 2	225	2009	2024	lignite	thermal	no	yes	yes	yes
Maritsa Iztok 3 unit 3	225	2009	2024	lignite	thermal	no	yes	yes	yes
Maritsa Iztok 3 unit 4	225	2009	2024	lignite	thermal	no	yes	yes	yes
CHP Ovcha Kupel 2	10	2014	2044	natural gas	CCGT	no	yes	yes	yes
CHP Ovcha Kupel 2	12	2017	2047	natural gas	CCGT	no	yes	yes	yes
CHP Zemlyame 1	45	2018	2046	natural gas	CCGT	no	yes	yes	yes
CHP Zemlyame 2	45	2019	2047	natural gas	CCGT	no	yes	yes	yes
TPP MI2	500	2018	2073	lignite	thermal	no	yes	yes	yes

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