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

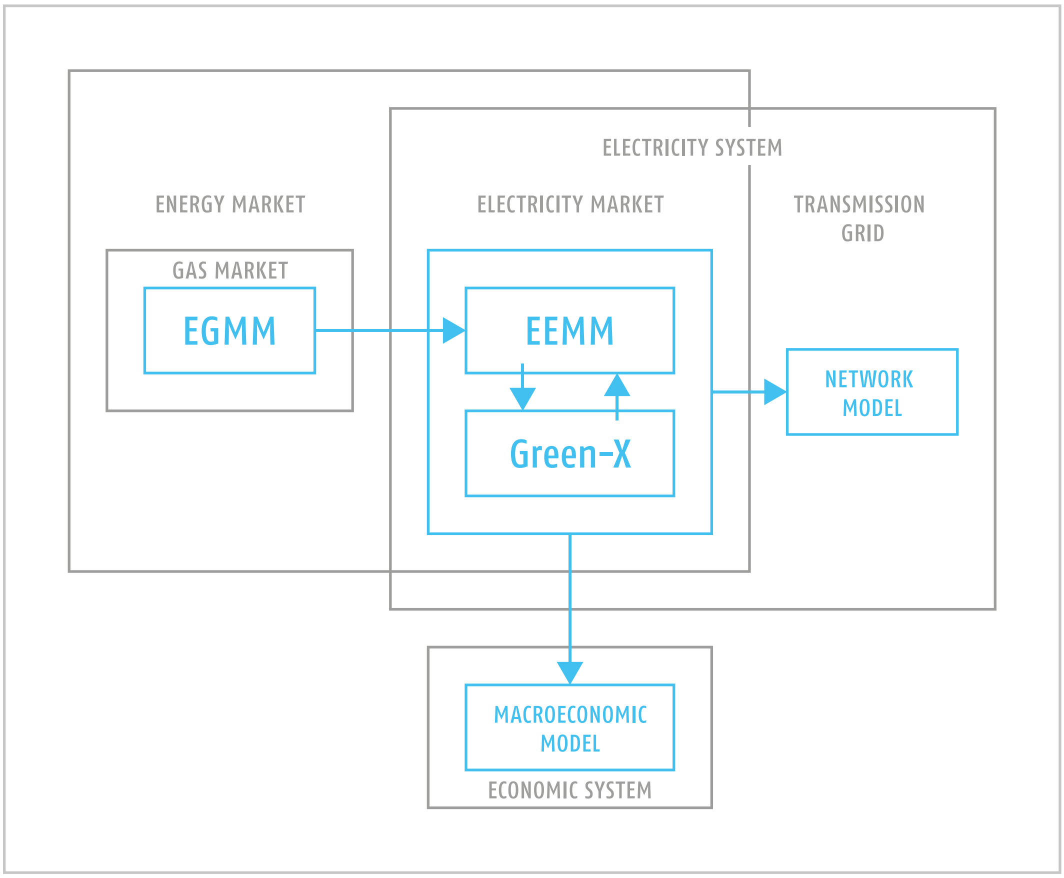
This report summarises the contribution of the SEERMAP project to the ongoing policy debate on how to enhance the decarbonisation of the electricity sector in South East Europe. We inform on the work undertaken, present key results gained and offer a summary of key findings and recommendations on the way forward.

Geographically we focus in this report on the whole South East Europe region, including the EU member states Bulgaria, Greece and Romania as well as the candidate and potential candidate countries Albania, Bosnia and Herzegovina, Kosovo*, Macedonia, Montenegro and Serbia. Please note that further information on the analysis conducted at country level can be found in the individual SEERMAP country reports.

3 | Methodology

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

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")



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 are captured by the model. The model is conservative with respect to technological developments and thus no significant technological breakthrough is assumed (e.g. battery storage, fusion, etc.).

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

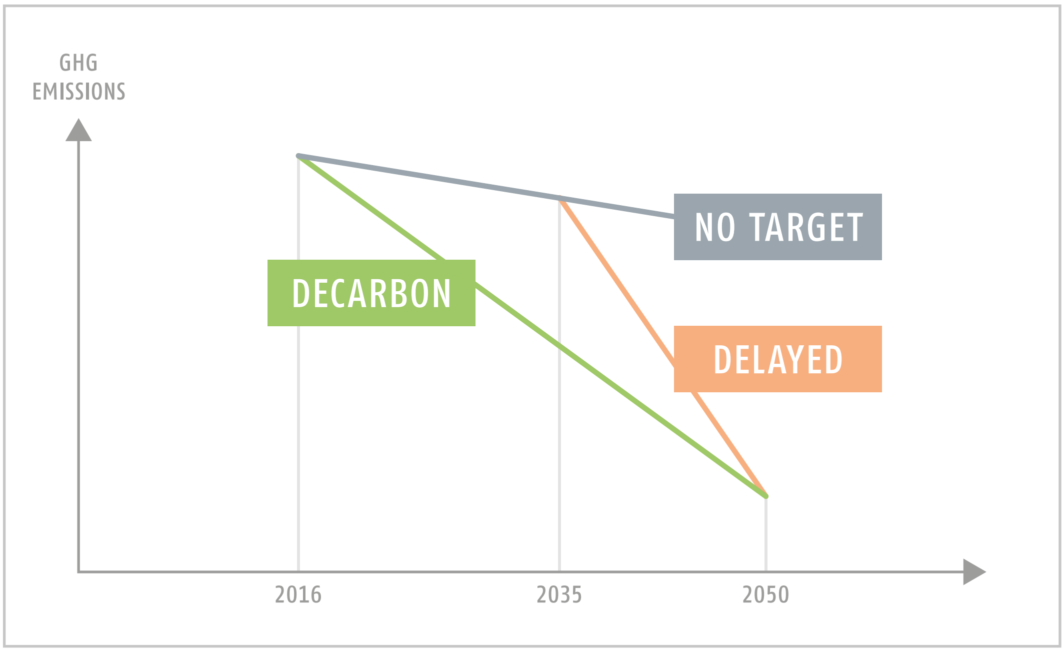
- The 'no target' scenario reflects the implementation of current energy policy and no CO_2 target in the EU and Western Balkans for 2050;
- The 'decarbonisation' scenario reflects a continuous effort to reach significant reductions of CO_2 emissions, in line with long term indicative EU emission reduction 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 modelling work does not take into account the impacts of the new Large Combustion Plant BREF (Commission Implementing Decision of 2017/1442), as it entered into force in July 2017.

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

The scenarios differ with respect to the mix of new technologies, included in the model in one of two ways: (i) the new power plants entered exogenously into the model based

FIGURE 2
THE CORE SCENARIOS



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). 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. The average annual electricity growth rate for the SEERMAP region as a whole is 0.74% over the period 2015 and 2050. The annual demand growth rate for countries within the region is varies significantly, with the value for Greece as low as 0.2%, and for Bosnia and Herzegovina as high as 1.7%. Whereas the growth rate in all EU3 countries is below 0.7%, Macedonia is the only country in the WB6 where the growth rate is below 1% a year.
- 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. The price of oil and coal were taken from IEA (2016) and EIA (2017) respectively. The price of both oil and coal is expected to increase by approximately 15% by 2050 compared with 2016. The gas price is differentiated by country, the increase in the price of gas is between 66 and 93% in the different countries in the SEERMAP region.
- Cost of different technologies: Information on the investment cost of new generation technologies is taken from EIA (2017).
- Weighted average cost of capital (WACC): The WACC has a significant impact on the cost of investment, with a higher WACC implying a lower net present value and therefore a more limited scope for profitable investment. The WACCs used in the modelling are country-specific, these values are modified by technology-specific and policy instrument-specific risk factors. The country-specific WACC values in the region are assumed to be between 10 and 15% in 2016, decreasing to between 9.6 and 11.2% by 2050. The value is highest for Greece in 2016, and remains one of the highest by 2050. In contrast, the WACC values for the other two EU member states, Romania and Bulgaria, are on the lower end of the spectrum, as are the values for Kosovo* and Macedonia. Other studies also estimated WACC values for the region and confirm that values are high. Ecofys – Eclareon (2017) estimated current WACC values for onshore wind to be between 7-13.7% and for PV between 7-12.4% for the EU3 countries. IRENA (2017) assumed medium level WACC values of 8 to 10% for SEE countries in 2016.
- Carbon price: a price for carbon is applied for the entire modelling period for EU member states and from 2030 onwards for 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. This Reference Scenario reflects the impacts of the full implementation of existing legally binding 2020 targets and EU legislation, but does not result in the ambitious emission reduction targeted by the EU as a whole by 2050. The corresponding carbon price, although significantly higher than the current price, is therefore a medium level estimate compared with other estimates of EU ETS carbon prices by 2050. For example, the Impact Assessment of the Energy Roadmap 2050 projected carbon prices as high as 310 EUR under various scenarios by 2050 (EC 2011b). The EU ETS carbon price is determined by the marginal abatement cost of the most expensive abatement option, which means that the last reduction units required by the EU climate targets will be costly, resulting in steeply increasing carbon price in the post 2030 period.

Infrastructure:

- Cross-border capacities: Data for 2015 was available from ENTSO-E with future NTC values based on the ENTSO-E TYNDP 2016 (ENTSO-E 2016) and the 100% RES scenario of the E-Highway projection (ENTSO-E 2015b).
- New gas infrastructure: In accordance with the ENTSO-G TYNDP 2017 both the TAP and 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

The main investment challenge in the SEERMAP region is replacing currently installed lignite and oil based capacities, of which more than 30% is expected to be decommissioned by the end of 2030 and more than 95% by 2050.

The model results show that the least cost capacity options under the assumed costs and prices are renewables (in particular wind, hydro and solar) in emission reduction target scenarios and a mix of natural gas and renewables in the 'no target' scenario.