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.

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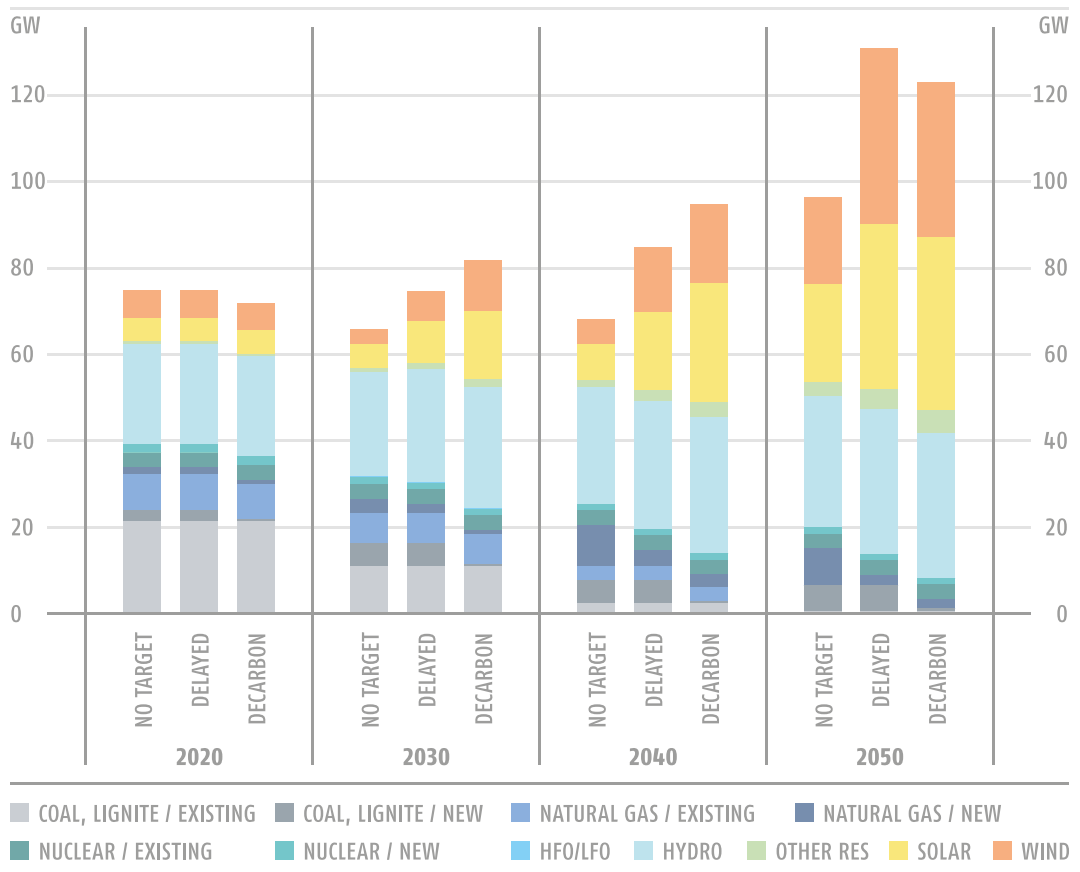


The capacity mix changes significantly in all three core scenarios, with a shift away from fossil based towards renewable capacity. The changes in the capacity mix are driven primarily by increasing carbon prices and decreasing renewable technology costs. Oil capacity disappears after 2035 in all scenarios, while coal and lignite based capacity drops from an initial 24.2 GW in 2016 to 6.6 GW by 2050 in the 'no target' and 'delayed' scenarios, and to 1.2 GW in the 'decarbonisation' scenario. By 2050, most of the coal capacity can be found in Bosnia and Herzegovina, Kosovo* and Serbia in both the 'no target' and 'delayed' scenarios according to model results, with 2000, 1100 and 1400 MW capacity respectively. In the 'decarbonisation' scenario the entire coal capacity in the SEERMAP region is based in 3 countries: Bosnia and Herzegovina, Bulgaria and Greece.

Nuclear capacity investment decisions have not been modelled, but were entered into the model exogenously; apart from the two existing plants in Bulgaria and Romania in Kozloduy and Cernavoda a new 1400 MW capacity nuclear plant is expected to begin operation in Romania by 2028 accorind to national plans.

Carbon capture and storage capacity does not enter into the model as the cost of CCS is higher than that of renewables. One 600 MW CCS lignite plant was included exogenously in the model in Kosovo* in the 'no target' and 'delayed' scenarios based on consultation with national stakeholders; the plant was assumed to come online in 2041.

Renewable capacity becomes increasingly important in all three scenarios. Investment in new wind capacities is significant, tripling in the 'no target' scenario from 6 GW in 2016 to around 20 GW in 2050. In the two scenarios with a decarbonisation target for 2050 the growth is even more significant, with wind capacity reaching 41 GW and 36 GW in the 2050 'delayed' and 'decarbonisation' scenarios respectively. Relative wind capacity

**20**

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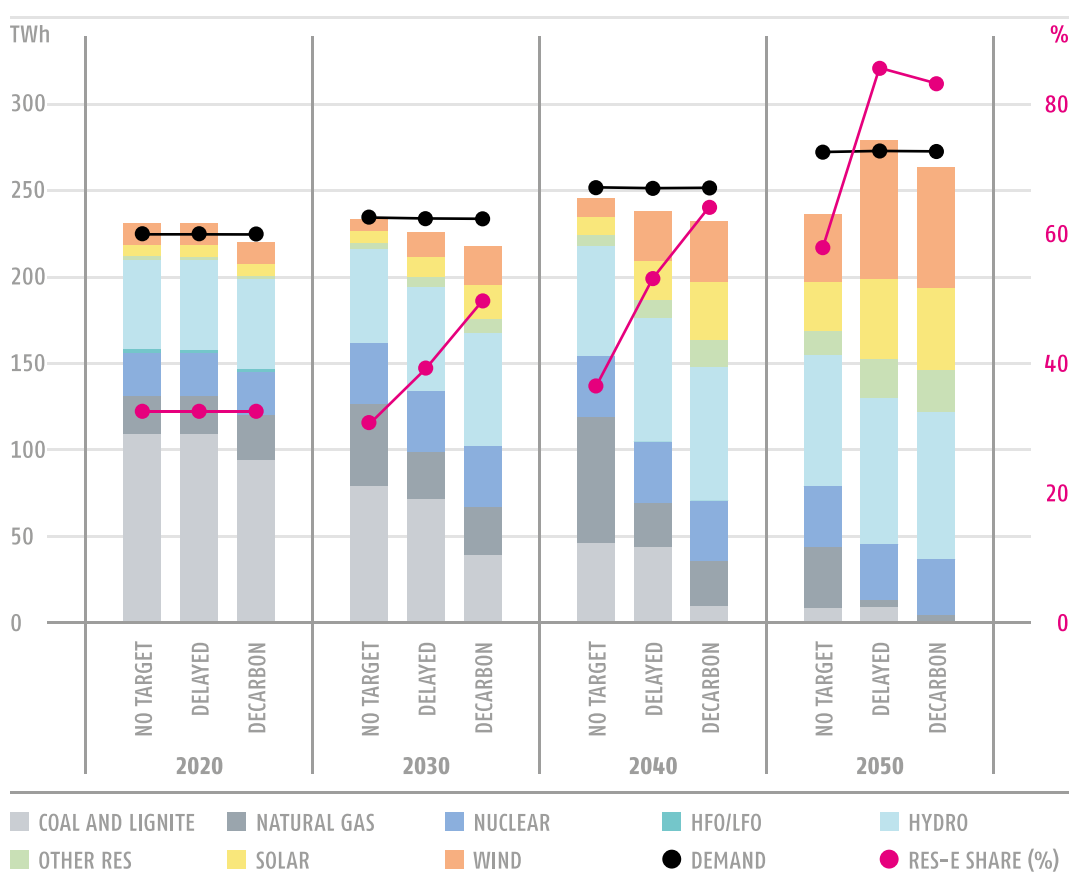


increase is especially high in the WB6 countries, where most countries have no or limited experience in operating wind farms.
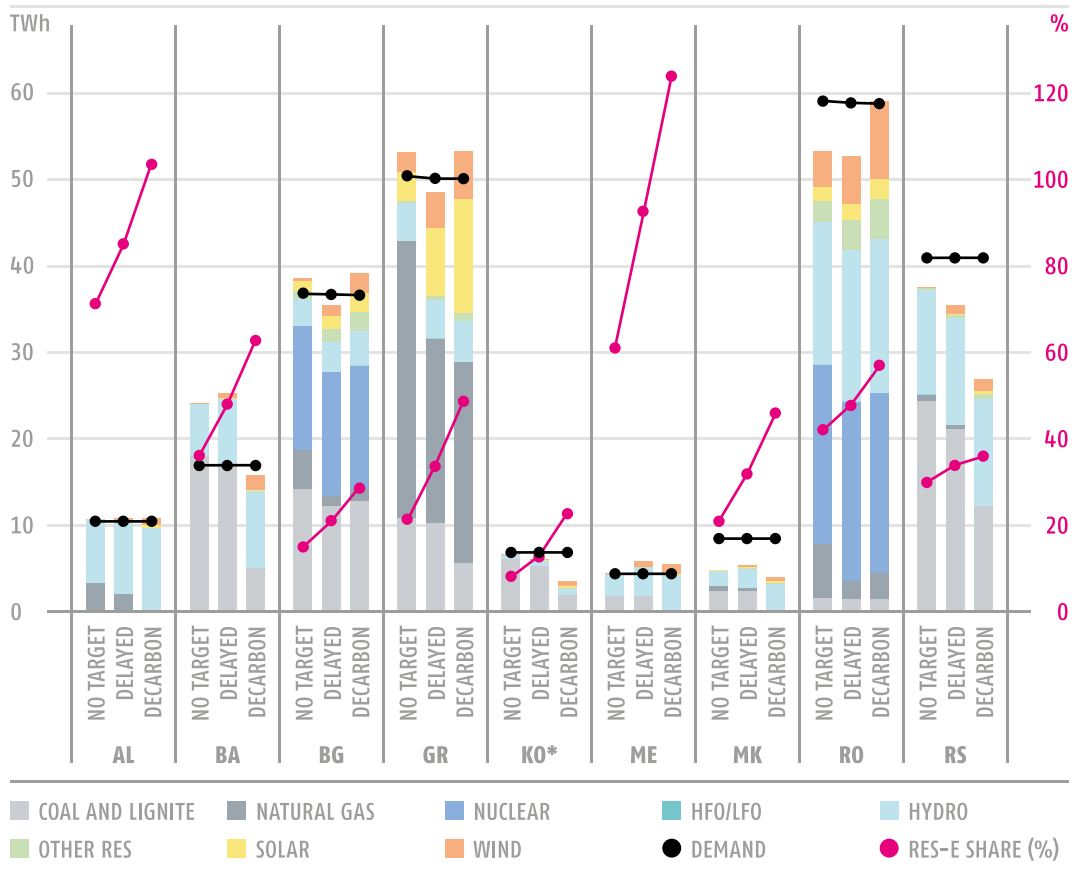
Solar capacity is comparable to wind capacity in the region by the end of the modelling period in all scenarios, moving from 5 GW in 2016 to some 23 GW in the 'no target', 38 GW in the 'delayed' and 40 GW in the 'decarbonisation' scenario by 2050. Although photovoltaic generation remains more expensive than wind generation throughout the modelled period, investment in small scale photovoltaic installations is boosted by its ability to compete in retail electricity markets whereas wind and large scale PV farms compete against the wholesale electricity price.

The relative increase in hydro capacity is the lowest of the three main RES technologies due to sustainability concerns and competing water uses. It increases by 40% in the 'no target' scenario and 54-55% in the other two other scenarios between 2016 and 2050. There is an especially low relative increase from current levels in hydro capacity in the EU3 in all scenarios, while growth rates are generally higher in the WB6.

Biomass makes up most of the 'other RES' category, with a share in total capacity of 3-4% in all scenarios by 2050, which represents approximately a 10-fold increase on 2016 levels in the 'no target' scenario, and almost 20-fold increase in the other two scenarios.

Natural gas investment shows very different patterns across the three core scenarios. Gas capacity increases by more than 40% by 2040 compared with 2016 in the 'no target' scenario, but then decreases to near current levels by 2050. In the 'delayed' scenario there is a 12% increase in gas capacity by 2025, followed by a reduction in capacity until 2050 settling near one quarter of current capacity. The 'decarbonisation' scenario entails even lower levels of initial growth in gas capacity, and gas based generation capacity

**FIGURE 5**

ELECTRICITY
GENERATION
AND DEMAND
(TWh) AND
RES SHARE
(% OF DEMAND)
BY COUNTRY,
2030



Legend:
- COAL AND LIGNITE
- NATURAL GAS
- NUCLEAR
- HFO/LFO
- HYDRO
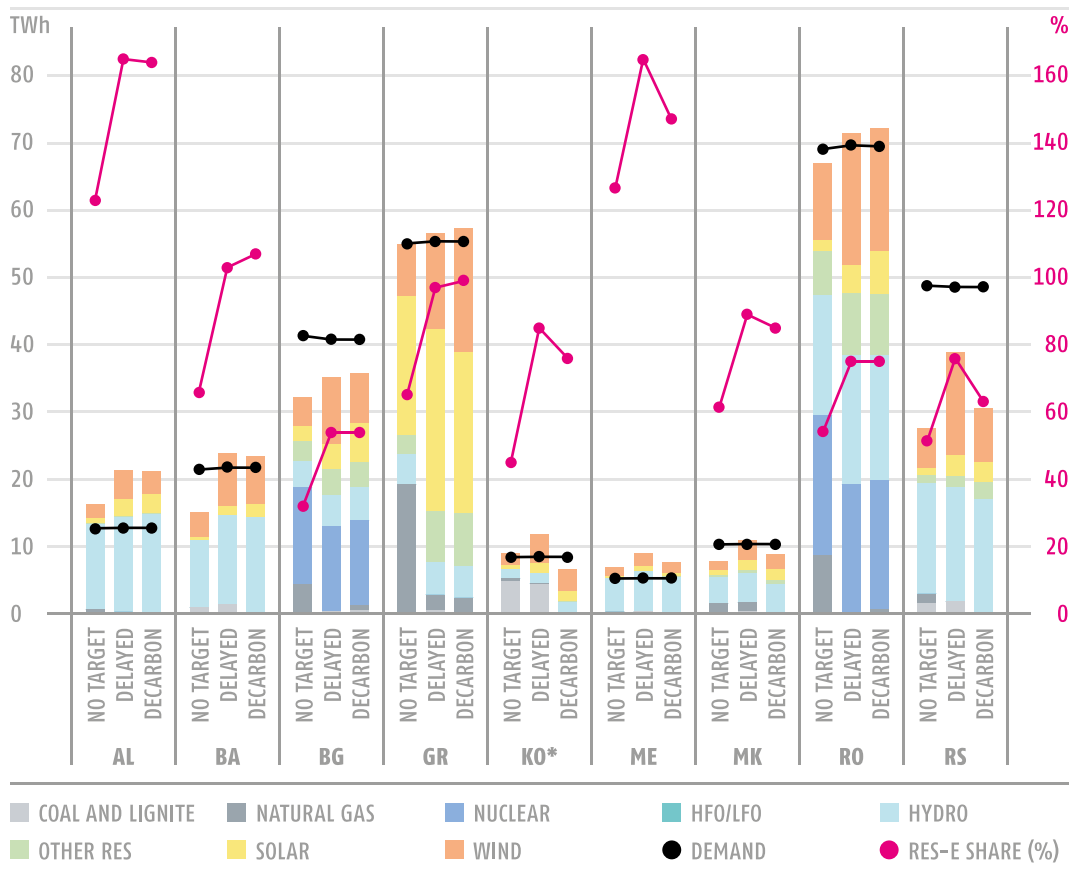- OTHER RES
- SOLAR
- WIND
- DEMAND
- RES-E SHARE (%)

peaks earlier, in 2020. In all scenarios, the bulk of natural gas capacity is located in the EU3 countries due to domestic gas production (especially in Romania) and their proximity to the TAP or TANAP pipelines (for Greece and Bulgaria) resulting in low transport costs.

The generation mix follows a similar pattern to the capacity mix. In all scenarios there is a significant increase in the share of renewables by 2050, with hydro, wind and solar making significant contributions. Hydro remains the renewable energy source with the highest contribution to generation in all three scenarios. Solar and wind have the highest relative growth by 2050 compared to 2016, with significantly lower growth in hydro. Wind has a relative advantage compared with solar in all countries in the region with the exception of Greece.

Natural gas plays a transitory role in electricity generation in all scenarios, with gas based generation peaking in 2040 in the 'no target' scenario, in 2025 in the 'delayed' scenario, and between 2025 and 2035 in the 'decarbonisation' scenario. The initial increase in gas based generation is driven by an increase in the carbon price, which prices out coal and lignite based generation before sufficient renewable capacity is installed. Later on gas based generation decreases as the carbon price increases further and renewable technologies become cheaper. While at its peak gas based generation is four times the current value in the 'no target' scenario, responsible for almost 30% of total generation, it is only twice the current value in the 'delayed' and 'decarboni-sation' scenarios. The divergent outcomes between the scenarios are due to different RES support patterns, which in some scenarios enable renewable based generation to compete successfully against natural gas earlier than in others. The temporary
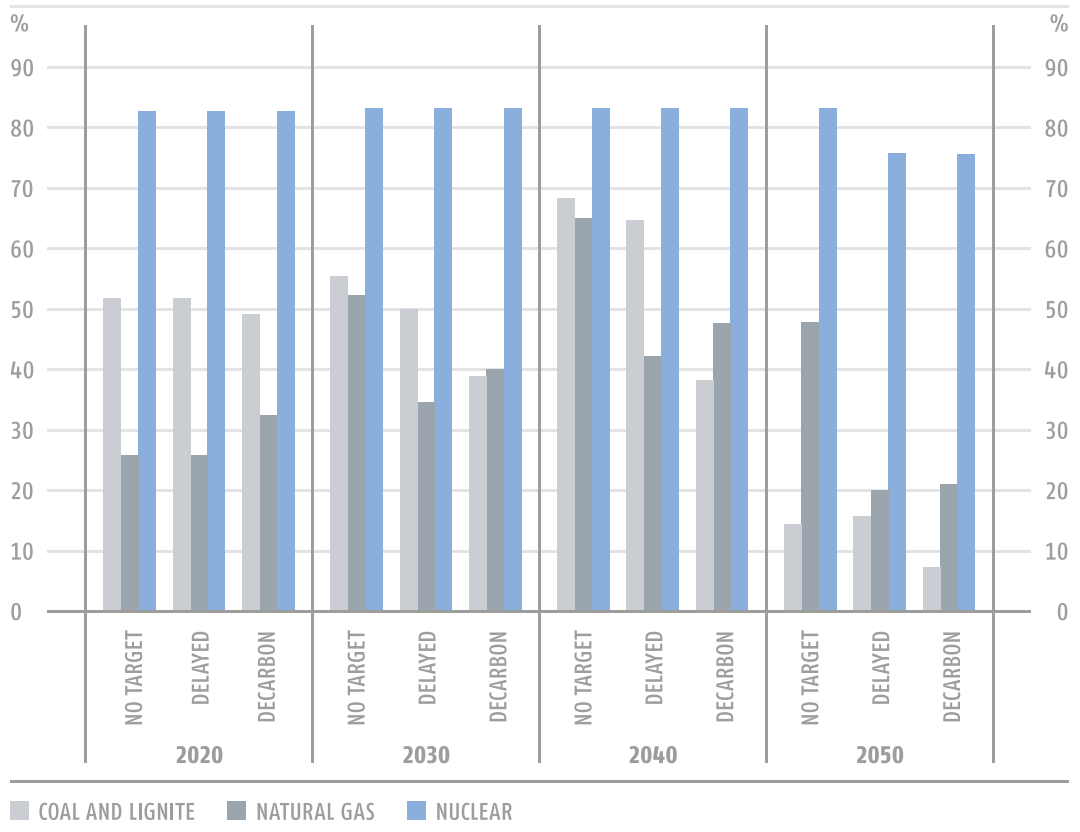
**FIGURE 6**

ELECTRICITY
GENERATION
AND DEMAND
(TWh) AND
RES SHARE
(% OF DEMAND)
BY COUNTRY,
2050



Legend:
- COAL AND LIGNITE
- NATURAL GAS
- NUCLEAR
- HFO/LFO
- HYDRO
- OTHER RES
- SOLAR
- WIND
- DEMAND
- RES–E SHARE (%)

increase in natural gas based generation is assisted in all scenarios by higher utilisa-tion rates of existing gas based generation capacities. In both the 'delayed' and 'decar-bonisation' scenarios most of the generation increase is due to higher utilisation rates, with increased capacity playing a role in the 'delayed' but not in the 'decarbonisation' scenario. In all scenarios most gas based electricity is produced in the EU3, especially in Greece during the middle of the modelled time horizon when RES is not sufficiently cheap but coal and lignite based generation is already decreasing. Two WB6 countries, Bosnia and Herzegovina and Montenegro, have no gas based electricity generation in any of the scenarios.

The SEERMAP region as a whole is currently almost self-sufficient, with low net elec-tricity imports, however, there is large variation among countries. The 'no target' scenario shows that the region as a whole will become a net exporter in the short term and a net importer from 2030 onwards, importing around 13% of its electricity consumption in 2050. The 'delayed' scenario also results in a net exporter position over the short term, but over the long term both the 'delayed' and 'decarbonisation' scenarios show that the region as a whole can become close to self-sufficient by the end of the modelled period as a result of increased investment in renewable generation. The net import positions of the individual countries within the region vary significantly. Some countries, such as Albania, become significant net exporters by the end of the modelled period under all scenarios, driven by the comparative competitiveness of hydro based generation, while Serbia will be a signifi-cant net importer. The net import position of individual countries is driven by very small differences in wholesale prices between the countries and can change significantly from one year to the next due to small price fluctuations. The regional net import position is

**23**

**FIGURE 7**
UTILISATION RATES OF CONVENTIONAL GENERATION IN THE SEERMAP REGION, 2020-2050 (%)

more stable with the electricity price spread between the region and other neighbouring countries higher than the intraregional spread, as shown in Figure 13.

The utilisation rate of coal plants remains relatively stable and even increases until 2040, depending on the scenario. However, these utilisation rates are lower than current levels which are typically more than 70%. Utilisation rates drop below those generally needed for commercial viability in 'decarbonisation' scenarios from 2030 onwards, and drop to very low rates by 2050 in all scenarios. Gas utilisation rates increase in all scenarios initially and peak in 2045 in the 'no target', 2035 in the 'delayed' and 2040 in the 'decarbonisation' scenario. Utilisation rates drop to low levels, around 20%, by the end of the modelled period in both scenarios with a decarbonisation target. This implies that if there is an ambitious decarbonisation target, the cost of gas based investments made at the beginning of the modelled period can be recovered but investments made closer to 2040 may be stranded. However, utilisation rates differ across countries, resulting in different levels of stranded costs. Coal investments made at any time during the modelled time period will also result in stranded assets. This issue is discussed further in section 5.4.

## 5.2 Security of supply

While the physical and commercial integration of national electricity markets naturally improves security of supply, decision makers are often concerned about the extent and robustness of this improvement, particulary for energy systems with 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 increasing the generation adequacy margin to zero.

**24**

**FIGURE 8**
GENERATION
AND SYSTEM
ADEQUACY
MARGIN FOR
THE SEERMAP
REGION,
2020-2050
(% OF LOAD)
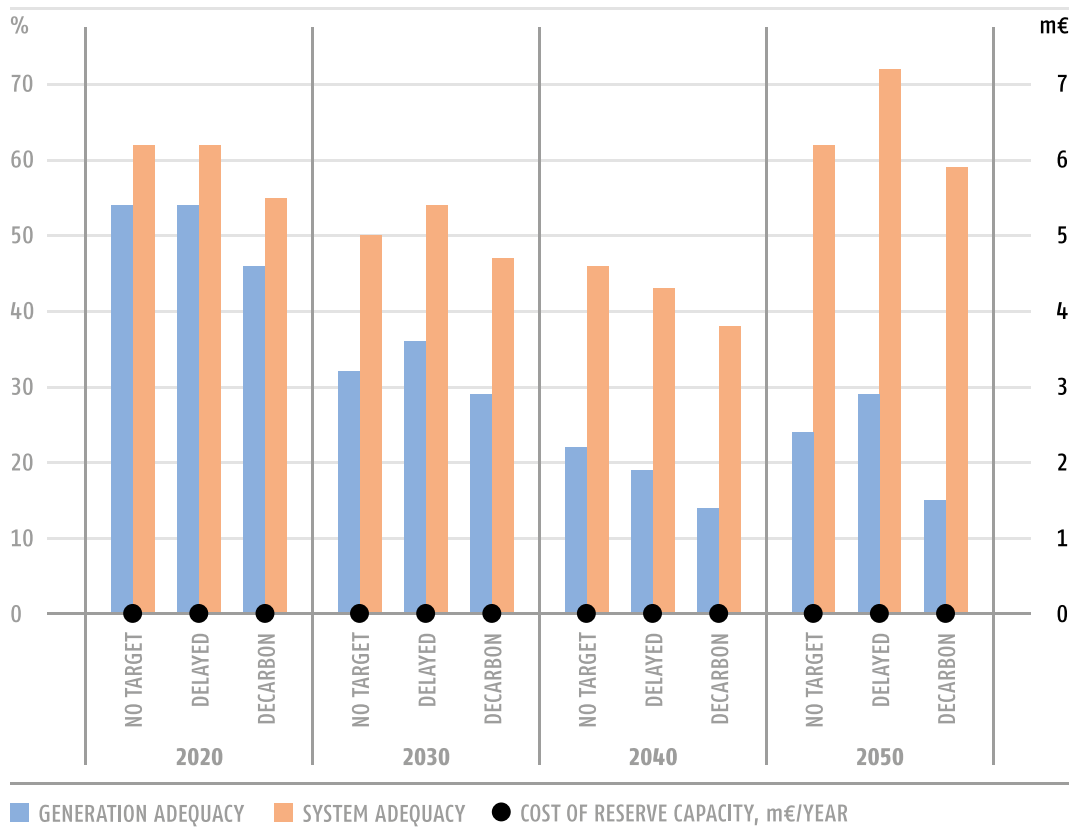


The generation adequacy margin is defined as the difference between available capacity and hourly load as a percentage of hourly load. If the resulting value is negative, the load cannot be satisfied with domestic generation capacities alone in a given hour and imports are needed. The generation adequacy margin was calculated for all of the 90 representative hours and the lowest value was used as the 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 (2015a), and previous SOAF reports)

For the SEERMAP region as a whole, the generation adequacy margin is positive throughout the modelling period, i.e. regional generation capacity is sufficient to satisfy regional demand in all hours of the year for all of the years shown. However, the generation adequacy margin is negative for some countries in some scenarios, in particular for Albania in 2020 and 2030 for all scenarios, for Kosovo* in 2040 and 2050 in the 'decarbonisation' scenario, and for Serbia for the entire period in the 'decarbonisation' scenario, and from 2035 onwards also in the other two scenarios. The system adequacy margin is higher than generation adequacy as it also accounts for import possibilities. Although there is significant variation among countries, the system adequacy margin is positive for all countries, enabling them to meet peak demand with their own generation capacity and imports at all times.

For negative generation adequacy indicators the cost of increasing the generation adequacy margin to zero was calculated. This is defined as the yearly fixed cost of an

**25**

**FIGURE 9** GENERATION AND SYSTEM ADEQUACY MARGIN (% OF LOAD) AND COST OF RESERVE CAPACITY (m€/YEAR) FOR THE SEERMAP COUNTRIES ('DECARBONISATION' SCENARIO) 2030 AND 2050

GENERATION ADEQUACY ■ SYSTEM ADEQUACY ● COST OF RESERVE CAPACITY, m€/YEAR
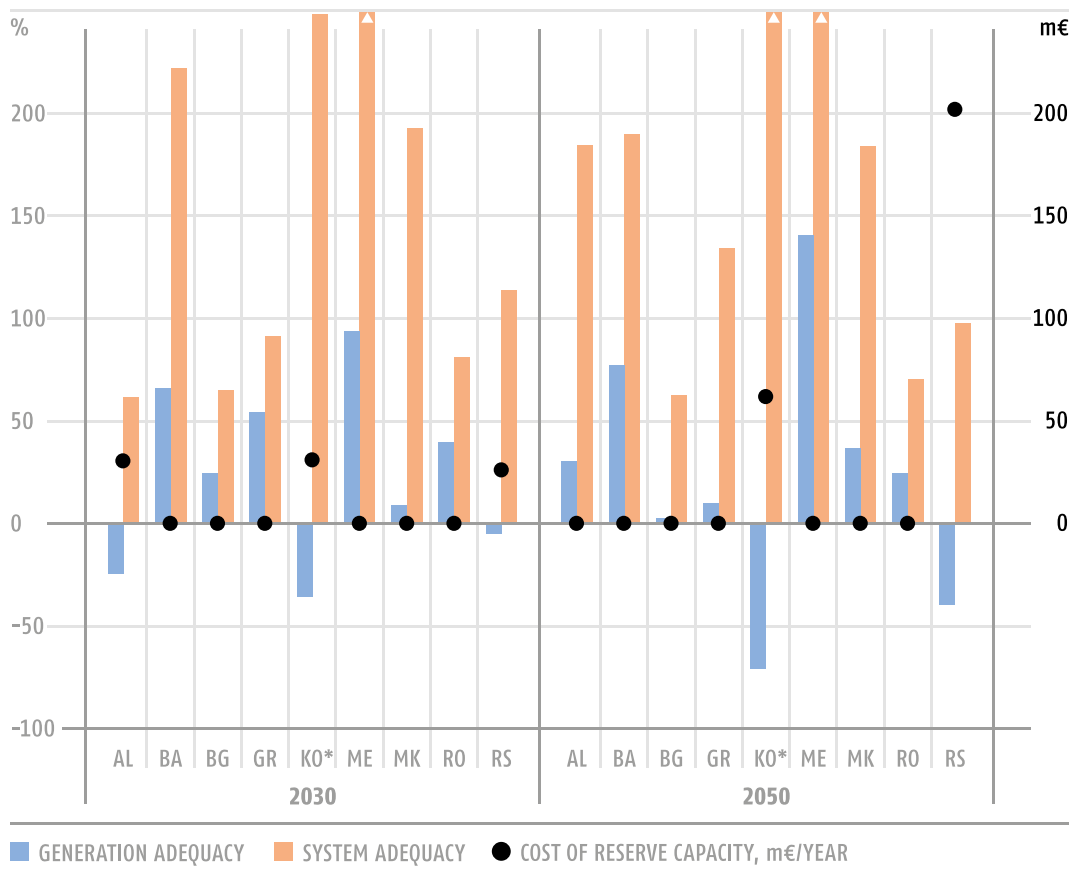
open cycle gas turbine (OCGT) which has adequate capacity to ensure that the generation adequacy margin reaches zero. This can be interpreted as a capacity fee, provided that capacity payments are only made to new generation, and that the goal of the payment is to improve generation adequacy margin to zero.

As the generation adequacy margin for the SEERMAP region as a whole is positive in all years for all scenarios, this cost for the region as a whole is zero. The country based adequacy margins are included in Figure 9 for the 'decarbonisation' scenario, showing that system adequacy values are positive for all countries. In 3 of the 4 countries where this value is negative, in Albania, Kosovo* and Serbia, the cost of increasing the generation adequacy margin to zero from an initial negative value is particularly high in the 'decarbonisation' scenario in some years. In Bulgaria, the value is high for the 'delayed' scenario in the second half of the modelled time period. This highlights the importance of regional markets and interconnections as a way of reducing costs in scenarios with high shares of renewable generation.

## 5.3 Sustainability

The $CO_2$ emissions of the three core scenarios were calculated, but due to data limitations this did not account for other greenhouse gases and only considered emissions from electricity generation, not including emissions related to heat production from cogeneration. The calculations were based on representative emission factors for the region.

The 94% decarbonisation target for the EU28+WB6 region translates into a higher than average level of decarbonisation in the SEERMAP region for the electricity sector. By 2050

**FIGURE 10**

CO₂ EMISSIONS
UNDER
THE 3 CORE
SCENARIOS IN
THE SEERMAP
REGION AND
IN THE EU+WB6,
2020-2050 (mt)
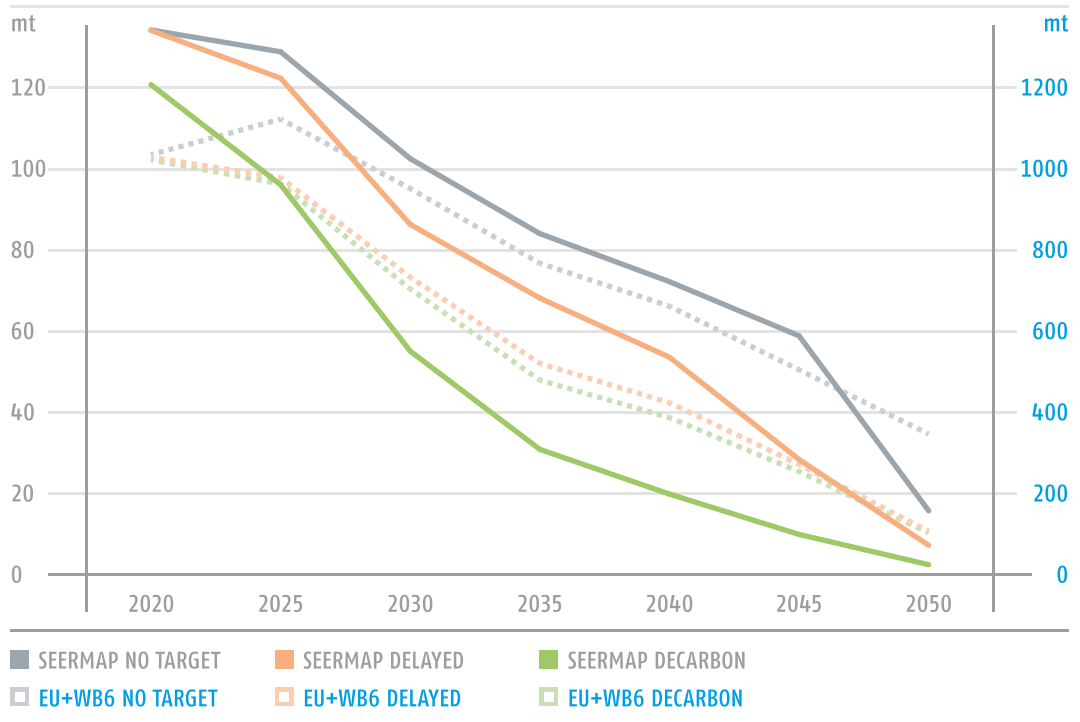


regional $CO_2$ emissions are 95.9% and 98.7% lower than 1990 levels in the 'delayed' and 'decarbonisation' scenarios respectively. This is due to a relative advantage for renewable electricity generation in the region compared with the European electricity sector in general, despite higher WACC levels in the region than in the EU. The comparative advantage rests in hydro potential and solar irradiation when compared to other European countries.

Emissions are also reduced significantly in the 'no target' scenario, reaching a 90.8% reduction by 2050. This is driven by the high price of carbon which leads to a massive reduction in coal based generation over the last 5 years of the modelled period and eventually erodes the competitiveness of gas based electricity generation over the long term.

The high level of emission reduction in the 'no target' scenario is made possible on the one hand by decreasing utilisation rates of fossil fuel power plants, especially coal and lignite due to lack of profitability, and on the other hand by the availability and viability of low carbon generation capacities. Bosnia and Herzegovina, Bulgaria, Greece, and Montenegro all have coal capacities which will finish operation before the end of their commercial lifetime due to lack of profitability resulting in stranded costs. In addition, the high level of emission reduction is enabled by an approximately 67% share of renewables in total generation, 15% nuclear generation in power plants located in Romania and Bulgaria, a contribution from the 600 MW CCS coal plant in Kosovo* which was included in the model exogenously, and a higher reliance on imports (around 13%) compared to the other scenarios.

The emissions profile of the countries in the region vary, but in the 'delayed' and 'decarbonisation' scenarios emission reduction in all countries is very high. Three countries, Macedonia, Montenegro and Serbia have a zero emissions electricity sector by 2050 under the 'decarbonisation' scenario.

The share of renewable generation as a percentage of gross regional consumption in the 'no target' scenario is 30.6% in 2030 and 57.8% in 2050. In the 'delayed' and 'decarbonisation' scenarios the share of renewable generation is 85.6% and 83.2% in

**FIGURE 11**
WEIGHTED
AVERAGE
WHOLESALE
ELECTRICITY
PRICE IN
THE SEERMAP
REGION,
2020-2050
(€/MWh)
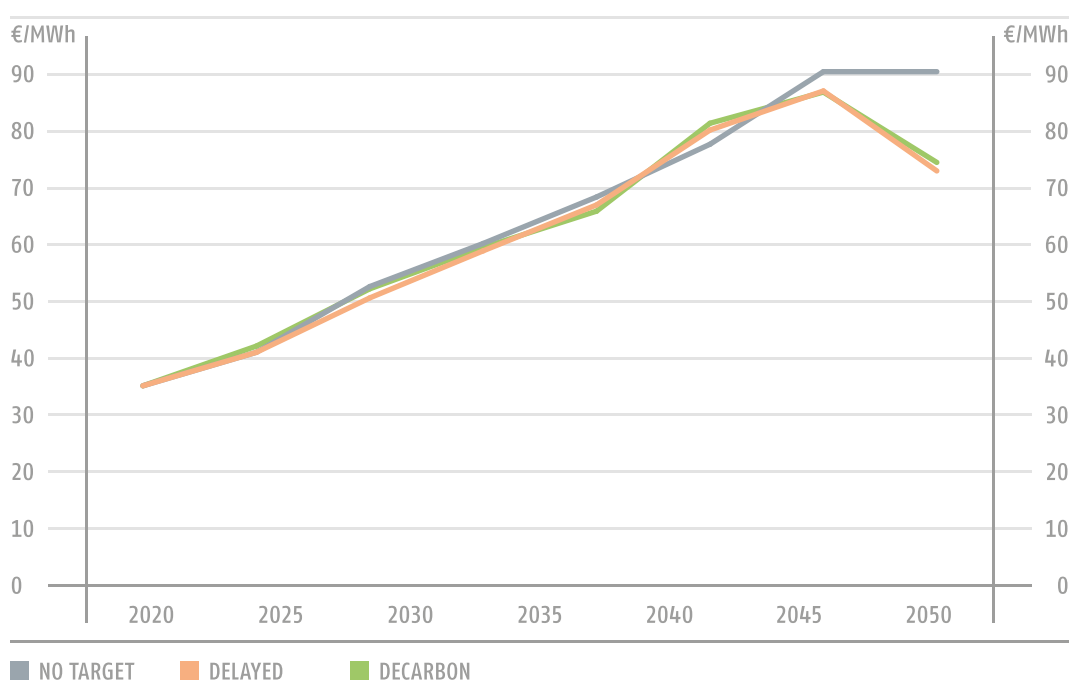


2050, respectively. Albania, Bosnia and Herzegovina and Montenegro have more than a 100% RES share in 2050 compared with domestic consumption in the 'decarbonisation' scenario due to electricity exports. In contrast, the RES share in Bulgaria and Romania is only 54% and 75% due to relatively higher cost of RES generation. In these countries decarbonisation is achieved in part due to the presence of nuclear generation.

The utilisation of long term RES potential in the 'decarbonisation' scenario will reach 51% for hydro, 58% for wind and 53% for solar. However, some national potential is almost fully utilised by 2050, for example in the decarbonisation scenario in Albania, Kosovo*, Montenegro and Macedonia 91%, 85%, 85% and 87% of long term hydro potential is estimated to be utilised. In Bosnia and Herzegovina and Montenegro 90% and 88% of long term wind potential is utilised. These high level utilsation rates need to be revisited once the ongoing revision of the Hypropower Development Study in the Western Balkans is finalised.

## 5.4 Affordability and competitiveness

In the market model (EEMM) the wholesale electricity price is determined by the highest marginal generation cost of the power plants needed to satisfy demand. Over the modelled time period wholesale prices rise significantly, driven by an increasing carbon price and the price of natural gas. The price trajectories are independent from the level of decarbonisation and similar in all scenarios until 2045 when the two scenarios with a decarbonisation target result in lower wholesale prices. Nearing 2050, the share of low marginal cost 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 in addition to taxes, fees and network costs. It is therefore difficult to project retail price evolution based on wholesale price information alone, but it is likely that an increase in wholesale prices will affect affordability for consumers since it is a key determinant of end user price. The average annual price increase in the

**FIGURE 12**

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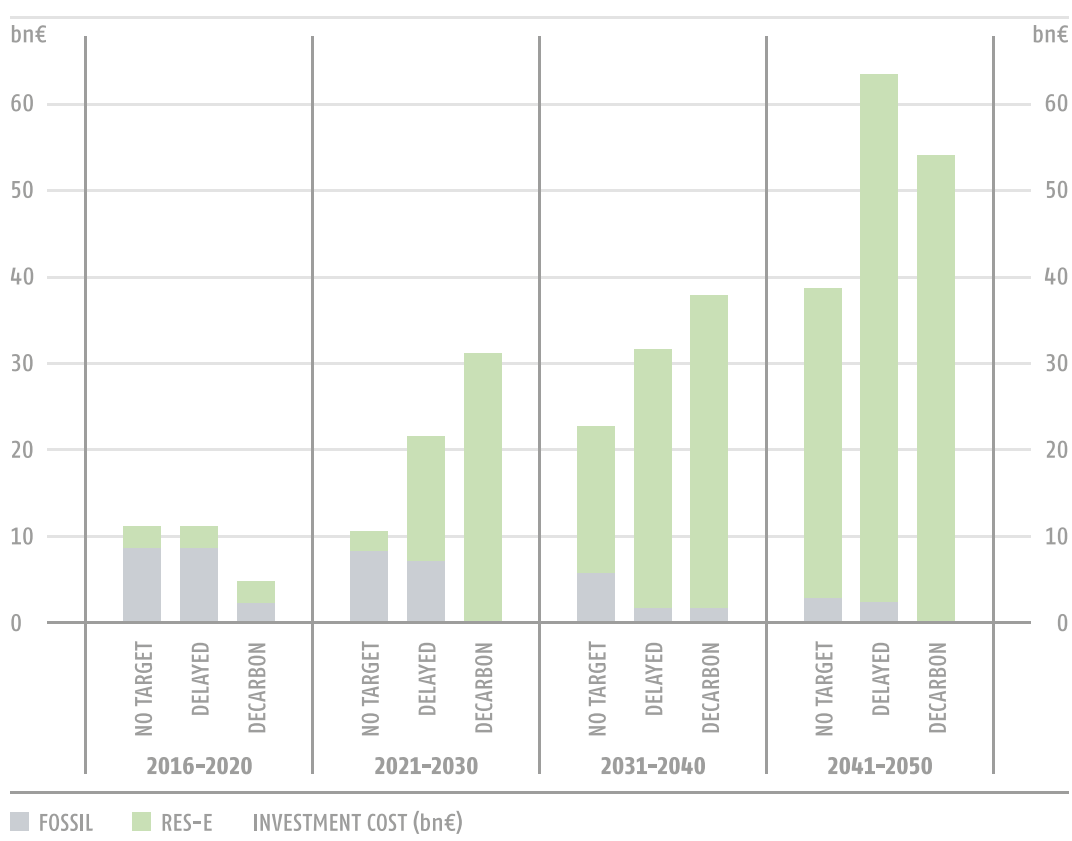


SEERMAP region over the entire period is 2.82% in the 'no target', 2.17% in the 'delayed' and 2.23% in the 'decarbonisation' scenarios.

There are slight differences between price levels of individual countries. The lower wholesale price increase in the two scenarios with a decarbonisation target are due to a fall in the wholesale price during the last 5 years of the modelled time period. Although the price increase is significant, it is important to note that 2016 wholesale electricity prices in Europe are at historical lows, the analysis projects wholesale prices to increase to approximately 60 EUR/MWh by 2030 which is the price level from 10 years ago. Assessing macroeconomic outcomes in section 5.7, if affordability is measured according to household electricity expenditure as a share disposable income, electricity remains affordable even with the price increase. Besides its negative effects, the price increase also has three positive implications, incentivising investment for new capacities, promoting energy efficiency and reducing the need for RES support.

The total regional investment needed in new capacities during the period until 2050 is lowest in the 'no target' scenario, at 83 bnEUR, and around 128 bnEUR in both the 'delayed' and 'decarbonisation' scenarios. (Investment needs do not account for investment costs of nuclear generation and investments in the transmission and distribution network.) Investment needs generally increase over the modelled time period in all scenarios due to the increasing share of new renewable capacities. As current investment levels in WB6 countries are far lower than these projections, the countries are likely to need exogenous support to mobilise funds for these investments in networks and RES generation. The EC can play crucial role in initialising this process.

It is important to note that investment is assumed to be financed by the private sector and based on a profitability requirement (apart from the capacities planned in

**29**

**FIGURE 13**
BASELOAD
WHOLESALE
PRICES IN
EUROPE IN 2030
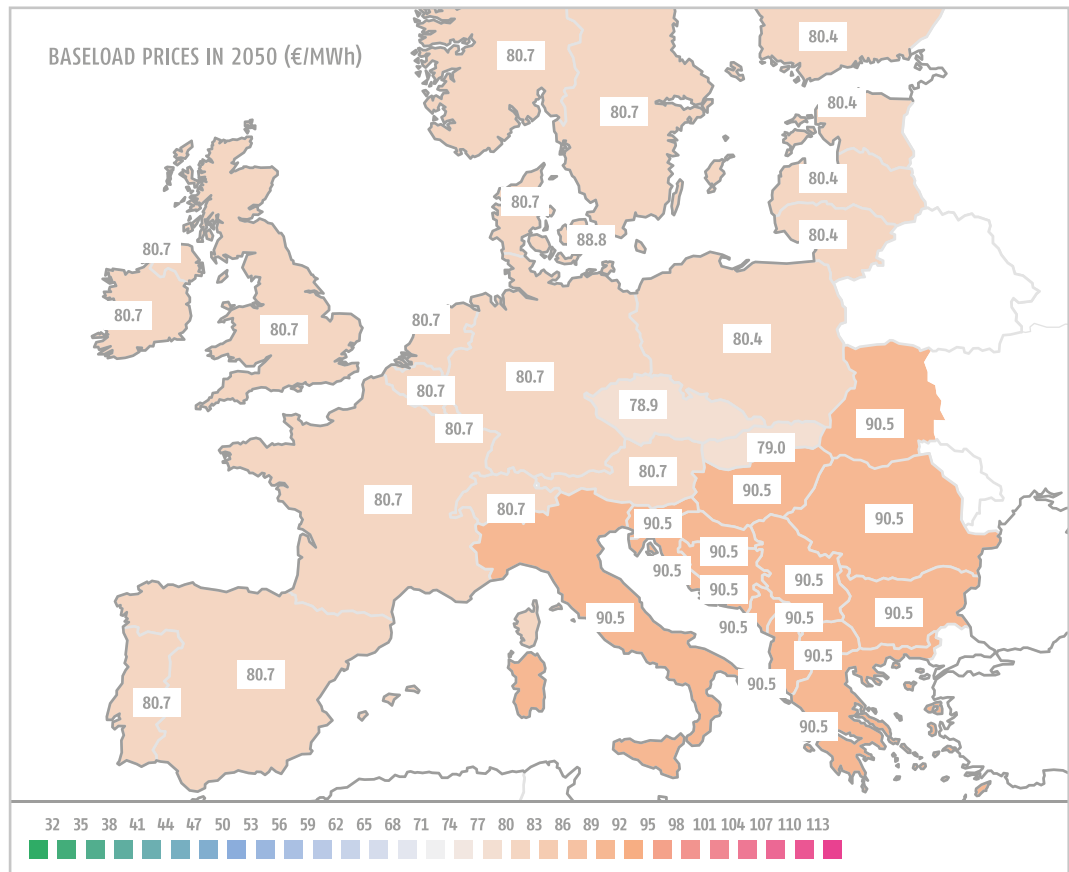AND 2050 IN
THE 'NO TARGET'
SCENARIO



BASELOAD PRICES IN 2030 (€/MWh)

32  35  38  41  44  47  50  53  56  59  62  65  68  71  74  77  80  83  86  89  92  95  98  101  104  107  110  113



BASELOAD PRICES IN 2050 (€/MWh)

32  35  38  41  44  47  50  53  56  59  62  65  68  71  74  77  80  83  86  89  92  95  98  101  104  107  110  113
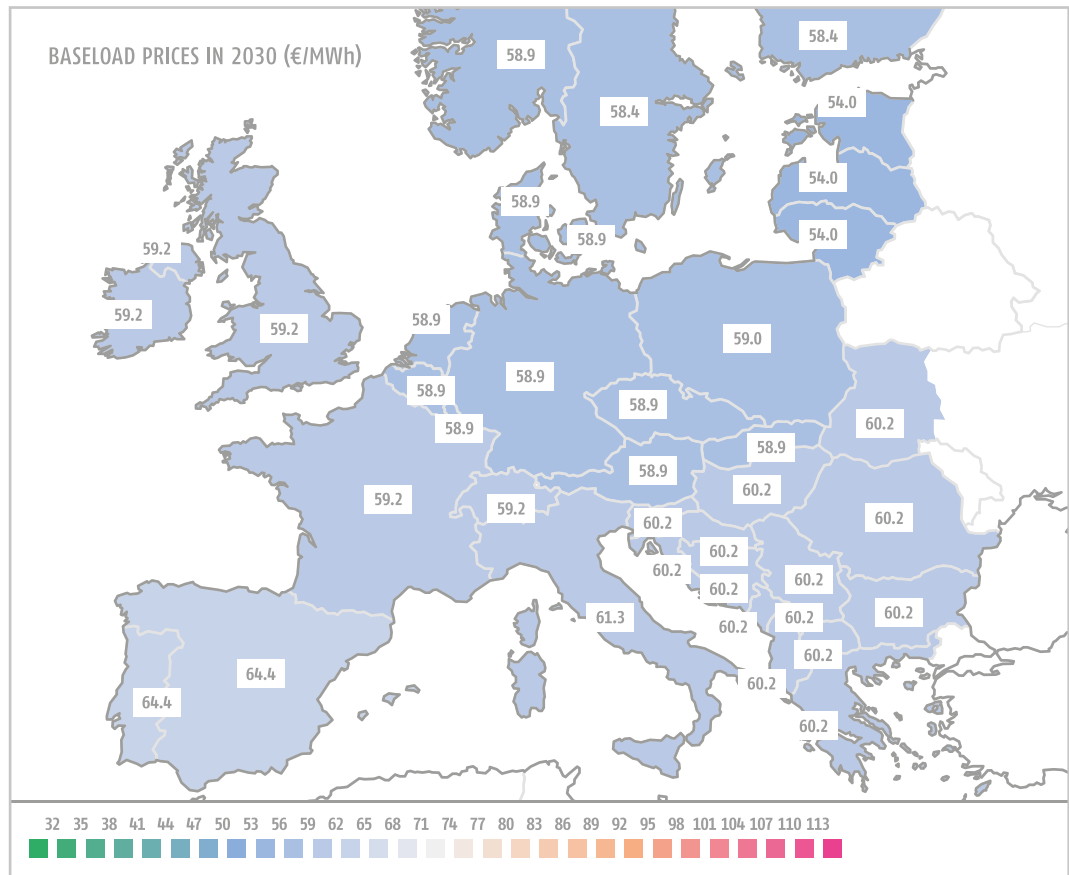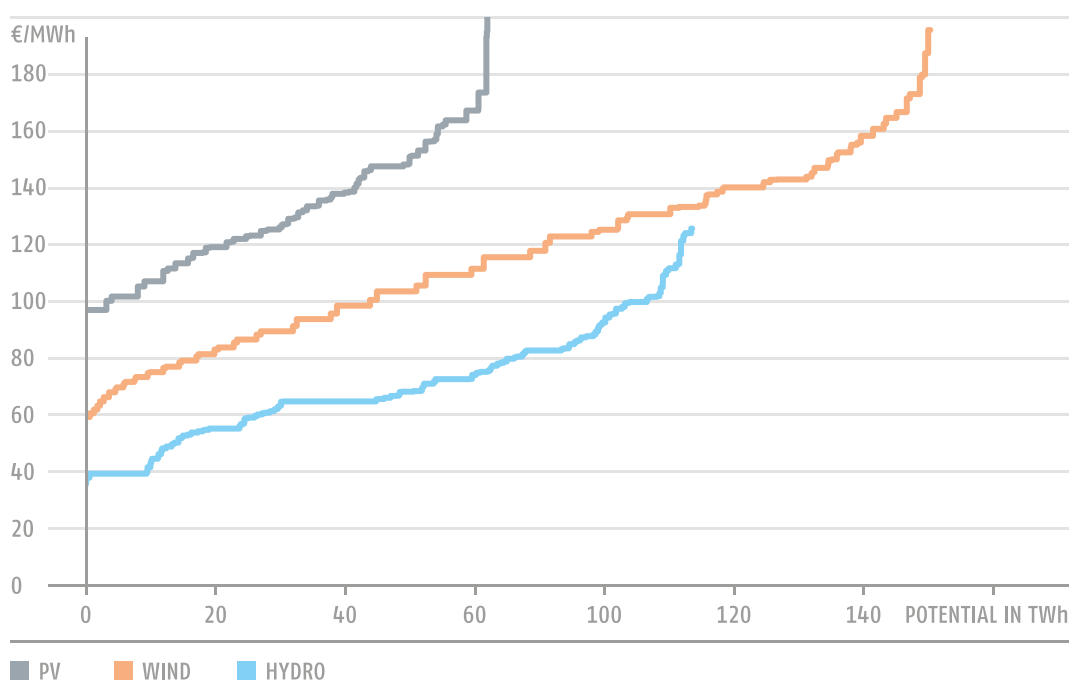
the national strategies). Here the different cost structure of renewables is important for the final investment decision, i.e. the higher capital expenditure is compensated by low operating expenditure. From a social welfare point of view, the consequences of the overall investment level are limited to the impact on GDP and a small positive impact on employment, as well as an improvement in the external balance. The technology choice affects electricity and gas imports, with higher share of renewables implying lower import levels. These impacts are discussed in more detail in section 5.7.

The price differentials within the modelled European countries depend on cross border network capacity constraints, which can prevent prices from equalising across all countries. The NTC values were taken from ENTSO-E sources, as indicated in section 4.2. Applying these NTC values, the forecasted demand profiles and the modelled electricity generation values, wholesale prices will be slightly higher in the SEERMAP region than in other EU countries in both 2030 and 2050, mainly as a result of the relatively higher gas prices in the region. This is due in part to the interconnection of the region with Italy, which drives prices up, and the capacity constraints along the northern borders of Italy, Slovenia and Hungary.

Despite the significant investment needs associated with the two emission reduction target scenarios, the renewables support needed to incentivise these investments decreases over time, with the exception of the 'delayed' scenario. The RES support needed to achieve almost complete decarbonisation in the 'decarbonisation' scenario relative to the wholesale price plus RES support is 10.8% in the period 2020-2025 but only 2.7% in 2045-2050. RES support decreases in the 'decarbonisation' scenario despite increasing investment in RES capacities, mostly because the rising wholesale electricity price reduces the need for additional support. Although some RES technologies have already reached grid parity, some support will still be needed in 2050 to stimulate new investment in each country in the two decarbonisation target scenarios. Since the best locations with highest potential are used first, it increases the levelised cost of electricity for new capacities. Technology learning on the other hand reduces LCOE, so the net impact is the result
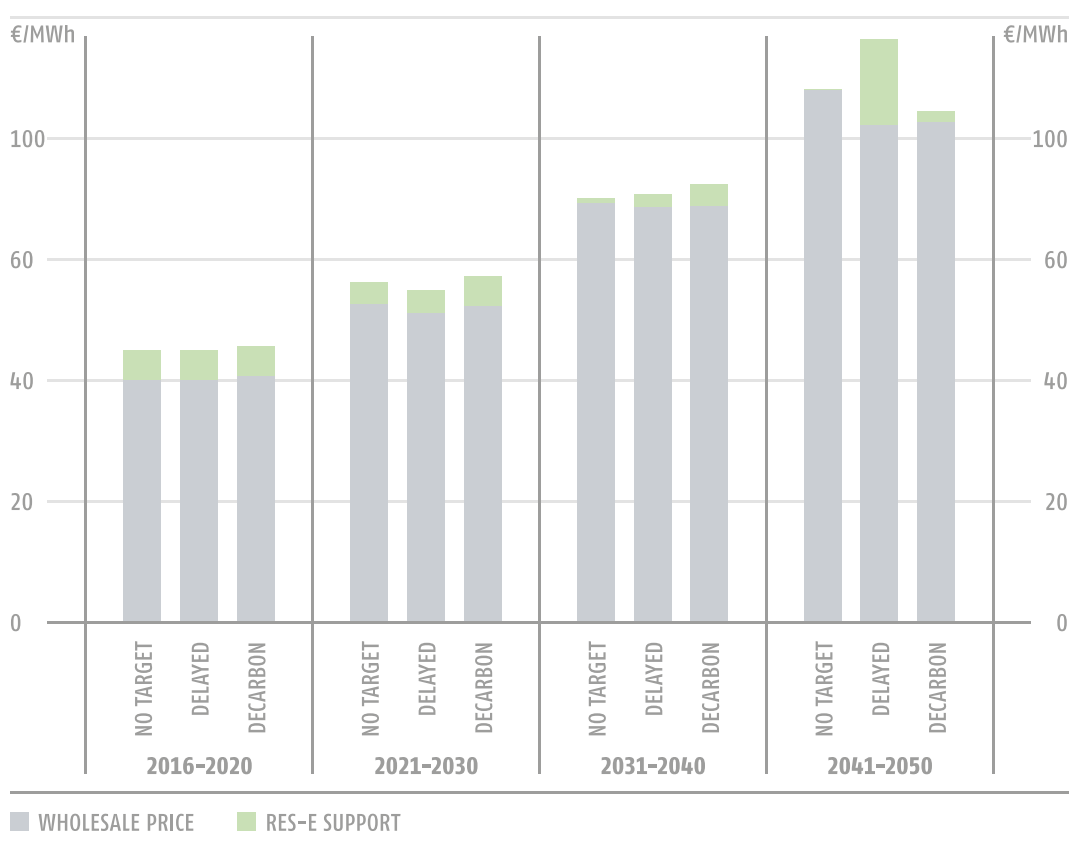
of these two opposing effects. The relationship between the cost of RES technologies and installed capacity is shown in Figure 14, but does not account for the learning curve adjustments which were embedded in the Green-X model).

The RES support needed in the 5 year period between 2045-2050 in the 'delayed' scenario is 24.3 EUR/MWh, compared with 2 EUR/MWh in the decarbonisation scenario, showing the high cost of delaying action on renewables.

Renewable energy investments may be incentivised through a variety of support schemes that secure funding from different sources, and in the model 'sliding' feed-in premium equivalent values are calculated. Revenue from the auction of carbon allowances under the EU ETS is one potential source of financing for renewable investment. Figure 16 compares cumulative RES support needs with ETS auction revenues, under an assumption of 100% auctioning and taking into account only allowances used in the electricity sector. The modelling results show that in the region as a whole ETS auctioning revenues are more than sufficient to cover the necessary RES support, with the exception of the last decade of the modelled time horizon in the 'delayed' scenario and the last five years in the 'decarbonisation' scenario. However, country level results can differ significantly, with auctioning revenues being lower than RES support needs in some countries for some years and scenarios.

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

**FIGURE 16**
ANNUAL
AVERAGE
RES SUPPORT
AND AUCTION
REVENUES FOR 4
AND 10 YEAR
PERIODS,
2016-2050 (m€)
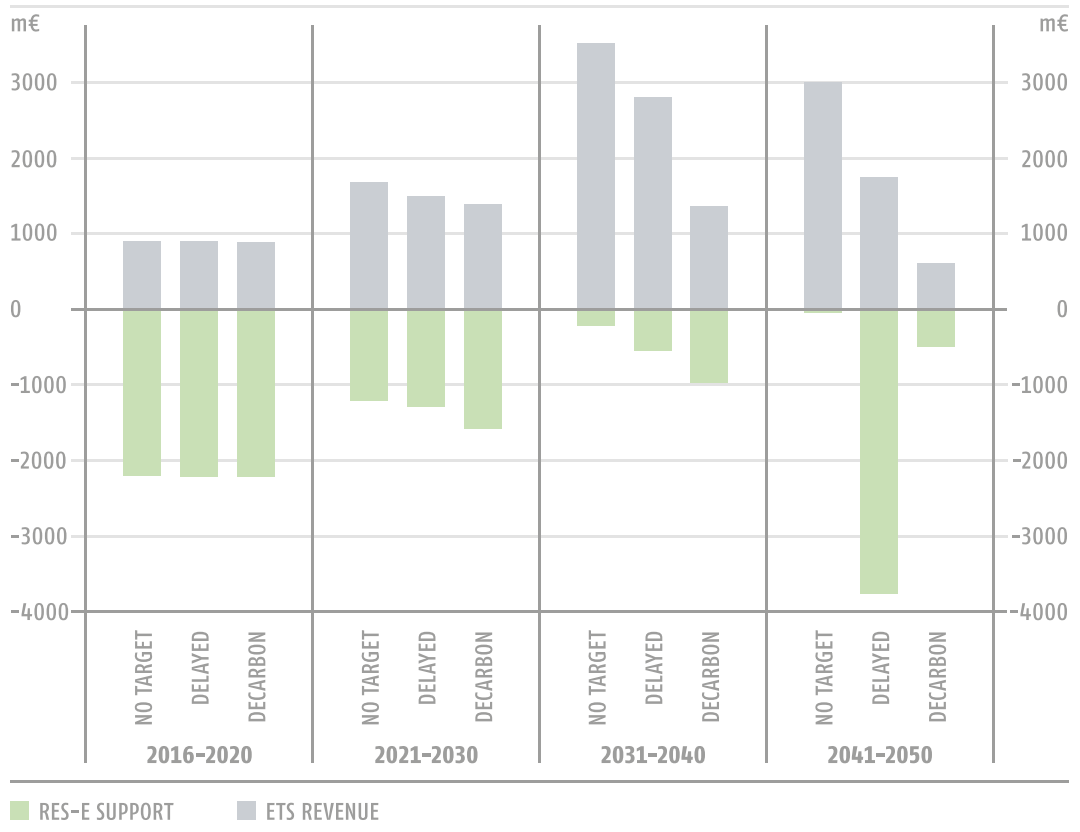


scenarios. This means that capacities which generally need to have a 30-55 year lifetime (30 for CCGT, 40 for OCGT and 55 for coal and lignite plants) with a sufficiently high utilisation rate in order to ensure a positive return on investment will face stranded costs.

Large stranded capacities will likely require public intervention, whereby costs are borne by society/electricity consumers. Therefore, the calculation assumes that stranded cost will be collected as a surcharge on the consumed electricity (as is the case for RES surcharges) over a period of 10 years after these gas and coal capacities finish their operation. Based on this calculations early retired fossil plants would have to receive 2.6 EUR/MWh, 2.5 EUR/MWh and 0.6 EUR/MWh surcharge over a 10 year period to cover their economic losses in the 'no target', 'delayed' and 'decarbonisation' scenarios respectively. These costs are not included in the wholesale price values shown in this report. Stranded costs are particularly high in Bosnia and Herzegovina, Greece and Kosovo* in both the 'no target' and 'delayed' scenarios.

## 5.5 Sensitivity analysis

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

● Carbon price: to test the impact of a lower $CO_2$ price, a scenario was run which assumed that $CO_2$ prices would be half of the value assumed for the three core scenarios for the entire period until 2050. Lower carbon price coupled with $CO_2$ reduction target means higher RES investment requirement to compensate for the 'missing' decarbonisation effect;

**33**

**FIGURE 17**

GENERATION MIX,
DEMAND (MWh),
RES SHARE (% OF
DEMAND) IN
THE SENSITIVITY
RUNS IN 2030
AND 2050
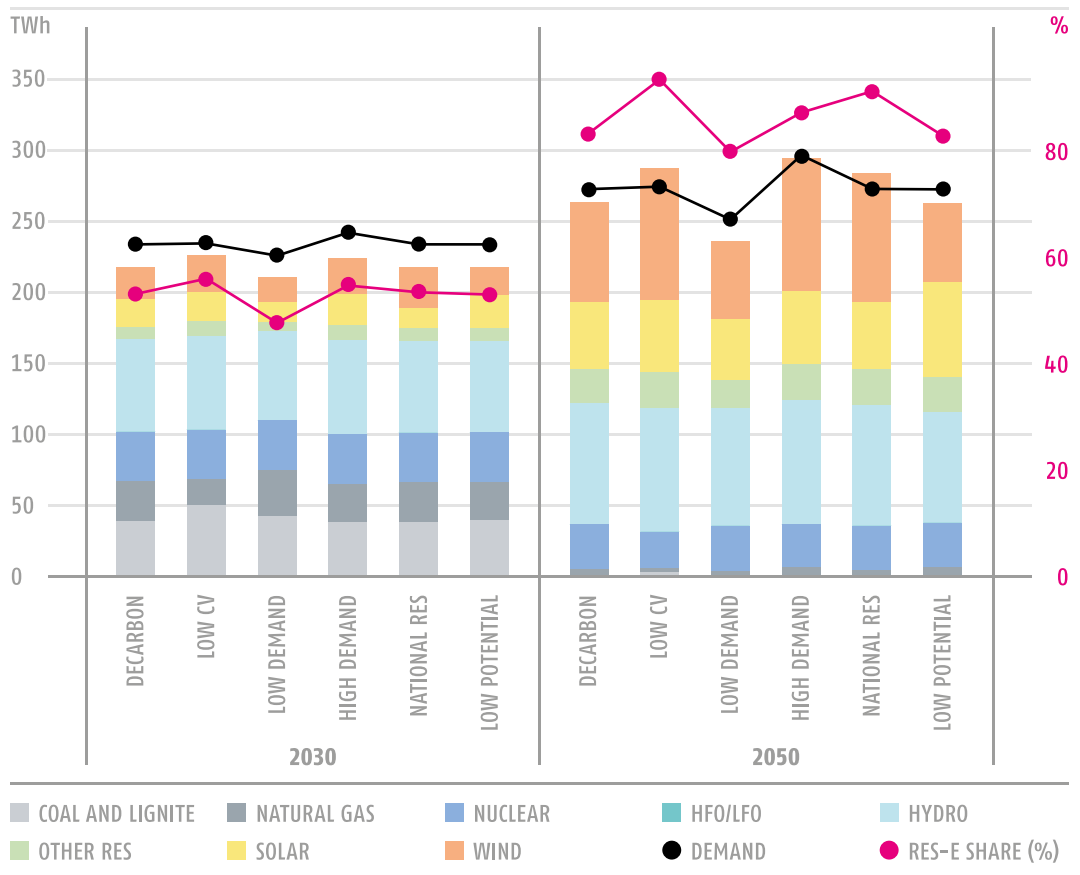


- Demand: the impact of higher and lower demand growth was tested, with a +/-0.25% change in the yearly growth rate for each year in all the modelled countries (EU28+WB6), resulting in a 8-9% deviation from the core trajectory by 2050;
- RES potential: the potential for large-scale hydropower and onshore 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;
- National renewable electricity targets: the core scenarios had assumed that the RES target was defined at a regional level, whereas the sensitivity analysis tested the impact of setting national rather than regional RES targets.

The adjustments were only applied to the 'decarbonisation' scenario since this is the scenario that represents a significant departure from current policy for many countries. Therefore, it is 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 reduces the wholesale price by a third over the long term. However, in order to ensure that the same decarbonisation target is met, the required RES support is almost four times as high in this run than in the 'decarbonisation' scenario. Because of this, the sum of the wholesale price and RES support is higher than in the 'decarbonisation' scenario in all countries with the exception of Serbia, indicating the important role that

**34**

the carbon price plays in incentivising a shift towards a low carbon electricity sector. The sensitivity assessment shows that the level of carbon price and the required RES support are linked to each other and should be optimised jointly for a cost efficient policy outcome.

- A lower carbon price would increase the utilisation rates of coal power plants by 10% in 2030 and more than 20% in 2050 compared with the 'decarbonisation' scenario. However, this increase in utilisation rates is not enough to make coal competitive by 2050.
- Gas utilisation rates fall with lower carbon prices due to stronger competition from coal based generation.
- Changing demand has only a limited impact on fossil fuel based capacities and generation. RES capacities and generation, in particular wind, are more sensitive to changes in demand.
- Lower hydro and wind potential leads to increased PV based capacity and generation. It also results in significantly higher RES support needs, which are more than four times the support levels needed in the 'decarbonisation' scenario.
- National renewable electricity targets result in higher overall investment and RES generation than regional targets. However, although RES generation in the region is only around 10% higher, the total support needed to achieve national targets is twice as high over the entire modelling period as in the case of a regional support framework. National targets are therefore less cost-effective than regional targets. However, the picture is less clear when we look at each country's contribution to RES support; if regional targets are combined with national support schemes then some countries will contribute more to overall support levels than under a national scheme. A regional target therefore warrants some sort of regional support scheme to ensure that the benefits of a regional target are distributed among all countries within the region.

## 5.6 Network

The transmission systems in the SEERMAP region are historically well-connected since the former Yugoslav Republics had strong interconnections with each other. In the future, additional network investments are expected to facilitate higher RES integration and cross-border electricity trade and to account for significant growth in peak load. The recorded peak load for the region in 2016 was 37 749 MW (ENTSO-E DataBase), while it is projected to be 42 429 MW in 2030 (SECI DataBase) and 49 760 MW in 2050. Consequently, domestic high voltage transmission and distribution lines will need significant investments in the future in most of the SEERMAP countries.

For the comparative assessment, a 'base-case' network scenario was constructed according to the SECI (Southeast European Cooperation Initiative) 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'.

The network analysis covered the following ENTSO-E impact categories: contingency analysis, TTC and NTC assessment and network losses.

Analysis of the network constraints anticipates contingencies in the SEE region. These problems can be solved by investments into the transmission network – e.g. by building additional lines or improving substations – where investment costs are estimated based on benchmark data for the region. The following two tables show where overloading and tripping can occur due to the changing production pattern in the SEE region envisaged in the 'delayed' and 'decarbonisation' scenarios in the years 2030 and 2050.

As the tables illustrate, tripping and overloading could occur in some specific areas, where the changing generation pattern – mainly due to new RES generation – would

**TABLE 1 | TRIPPINGS AND OVERLOADINGS DETECTED
IN THE SEERMAP COUNTRIES TRANSMISSION SYSTEM, 2030**

| Scenario | Tripping | Overloading | Solution | Units (km or pcs) | Cost m€ |
|---|---|---|---|---|---|
| Delayed scenario | OHL 220 kV Fierza(AL) – Titan(AL) | OHL220 kV VauDejes(AL) – Komani (AL) | New OHL 220 kV Komani(AL) – Titan (AL) | 70 | 11.15 |
| | Several contingencies | OHL 110 kV Alibunar – Pancevo (RS) | New OHL 110 kV Bela Crkva – Veliko Gradiste | 35 | 2.80 |
| | OHLs 110 kV WPP Bela Anta – WPP Alibunar or WPP Bela Anta – WPP Košava (RS) | WPP Bela Anta – WPP Košava, or OHLs 110 kV WPP Bela Anta – WPP Alibunar (RS) | Reconstruction of the OHL from 150 mm² to 240/40 mm² | 65 | 6.50 |
| | OHL 110 kV Bar (ME) – WPP Mozura (ME) | WPP Mozura must go out of operation | New OHL 110 kV Ulcinj (ME) – Virpazar (ME) | 40 | 3.50 |
| Decarbon scenario | OHL 220 kV Komani (AL) – Kolace(AL) | OHL220 kV VauDejes(AL) – Komani (AL) | New OHL 220 kV Komani – Titan (AL) | 70 | 11.15 |
| | Several contingencies | OHL 110 kV Brezna (ME) – Klicevo (ME) | New SS 400/110 kV Brezna for RESs collection | 1 | 20.00 |
| | Several contingencies | OHL 110 kV Alibunar – Pancevo | New OHL 110 kV Bela Crkva – Veliko Gradiste | 35 | 2.80 |
| | OHLs 110 kV WPP Bela Anta – WPP Alibunar, or WPP Bela Anta – WPP Košava (RS) | WPP Bela Anta – WPP Košava, or OHLs 110 kV WPP Bela Anta – WPP Alibunar | Reconstruction of the OHLs in the area of RESs from 150 mm² to 390/65 mm² | 65 | 8.50 |
| | OHL 110 kV Bar (ME) – WPP Mozura (ME) | WPP Mozura must go out of operation | New OHL 110 kV Ulcinj (ME) – Virpazar (ME) and OHL 110 kV Virpazar – Golubovci – Podgorica 1 | 80 | 8.00 |
| | OHL 110 kV Danilovgrad (ME) – HPP Perucica (ME) | OHL 110 kV HPP Perucica – Podgorica | New OHL 110 kV Vilusi (ME) - H.Novi (ME) | 40 | 5.50 |
| | New RESs | OHLs 110 kV in the area of Tulcea West (RO) | New single circuit OHL 400 kV Gadalin (RO) – Sucaeva (RO) enables RES penetration from WF | 260 | 52.00 |
| | 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 | 25.00 |
| | New RESs | Southern Aegean Interconnector (GR) AC submarine cables (150 kV or 220 kV) | 2 converter SS + 270 km DC subm. Cable Connection Wind Farms with AC Substations at Levitha and Syrna. AC Submarine cable to connect Kinaros Offshore Wind Farm HiV sub station to the AC side of Levitha Converter SS | several HVDCs | 1800.00 |
| | New RESs | OHLs 110 kV in the area of east part of Romania with RESs | New 400kV double circuit OHL (one circuit wired) between existing substations, Smardan (RO) – Gutinas (RO) | 140 | 65.00 |
| | 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 | 35.00 |

cause network problems. In the 'delayed' scenario additional transmission network costs are 24 and 64 mEUR in 2030 and 2050, for the 'decarbonisaiton' scenario these values are 233 and 132 mEUR (not including the value for Greece). These costs are not significant compared to the overall investment costs in RES generation capacities, and demonstrates that moderate investments in transmission line development will ensure that the network will not constrain significantly the higher level of RES deployment projected for the region. However, it has to be emphasised that these cost estimates only cover transmission network development and do not include the cost of the required development of distribution networks which could be significantly higher.

Total and Net Transfer Capacity (TTC/NTC) changes were evaluated between all bordering countries in the region 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 exactly) significantly influence NTC values between the neighbouring electricity systems. We can distinguish two opposite impacts of higher RES deployments on the NTC values. First, the high concentration of RES in a geographic area may cause congestion in the transmission

**TABLE 2 | TRIPPINGS AND OVERLOADINGS DETECTED
IN THE SEERMAP COUNTRIES TRANSMISSION SYSTEM, 2050**

| Scenario | Tripping | Overloading | Solution | Units (km or pcs) | Cost m€ |
|---|---|---|---|---|---|
| Delayed scenario | TR 400/220 kV Fier (AL) | OHL220 kV Fier(AL) – RRasbull (AL) | New TR 400/220 kV Fier (AL) | 1 | 3.00 |
| | | | SS Skakavica (AL) + 400 kV OHLs (to Tirana (AL) and Prizren (KS) New HPP Skakavica is going to be connected to the OHL 400 kV Tirana (AL) – Prizren (KS) | 130 + SS 400 kV | 65.00 |
| | OHL 400 kV RP Drmno(RS) –Smederevo(RS) | OHL 400 kV Pancevo(RS) – Beograd (RS) | Change of the Conductors and earthwires and OPGW across the Danube river with higher capacity (1km) | 1 | 0.08 |
| Decarbon scenario | TR 400/220 kV Fier (AL) | OHL220 kV Fier (AL) – RRasbull (AL) | New TR 400/220 kV Fier (AL) | 1 | 3.00 |
| | Several contingencies | several overloadings in 110 kV network close to RESs | SS 400/110 kV Belgrade West (part of it is related to RES integration) | 1 | 20.00 |
| | OHL 400 kV RP Drmno(RS) – Smederevo(RS) | OHL 400 kV Pancevo(RS) – Beograd (RS) | Change of the Conductors and earthwires & OPGW across the Danube river with higher capacity (1km) | 1 | 0.08 |
| | 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 | 31.00 |
| | | | SS Skakavica (AL) + 400 kV OHLs New HPP Skakavica is going to be connected to this SS | 130+SS 400 kV | 65.00 |
| | OHL 400 kV Elbasan (AL) – Fier (AL) | OHL220 kV Fier(AL) – RRasbull (AL) | Second line OHL220 kV Fier(AL) – RRasbull (AL) | 80 | 12.00 |
| | 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 | 0.70 |

network, reducing NTCs and requiring further investment. Second, if RES generation replaces imported electricity it may increase NTC for a given direction.

The network assessment also analysed the changes in NTC values for 2030 and 2050, but no clear trend could be observed. Out of the 18 analysed borders, there are only four – Bulgaria-Serbia, Bulgaria-Romania, Albania- Kosovo*, Albania-Macedonia – where NTC change is always positive in the six cases that were examined (two scenarios, two years and two seasons). In three directions–Macedonia-Serbia, Albania-Greece and Bulgaria-Greece–the NTC change is always negative for the six cases. This leads to the conclusion that large RES triggers congestion and reduces trade options. But in the other 11 directions the picture is mixed and no clear trend can be observed in the NTC variations.

Transmission network losses are affected in different ways. For one, losses are reduced as renewables, especially PV, are generally connected to the distribution network. However, high levels of electricity trade observable in 2050 will increase transmission network losses. Figure 17 shows that in the 'decarbonisation' and 'delayed' scenario transmission losses decrease significantly compared to the 'base case' scenario.

As Figure 18 illustrates, higher RES deployment in the two scenarios reduces transmission losses significantly, between 100-300 MW in 2030 and between 300-500 MW in 2050 during the modelled hours. This represents a 1500 GWh loss variation in 2030 and over 1700 GWh in 2050 in the 'decarbonisation' scenario. The 'delayed' scenario represents lower loss reduction values compared to the 'decarbonisation' scenario, which indicates lower benefits in the 'delayed' scenario. If this is monetised using the base load wholesale electricity price, the concurrent benefits for TSOs are in excess of 130 mEUR for the 'decarbonisation' scenario in 2050.
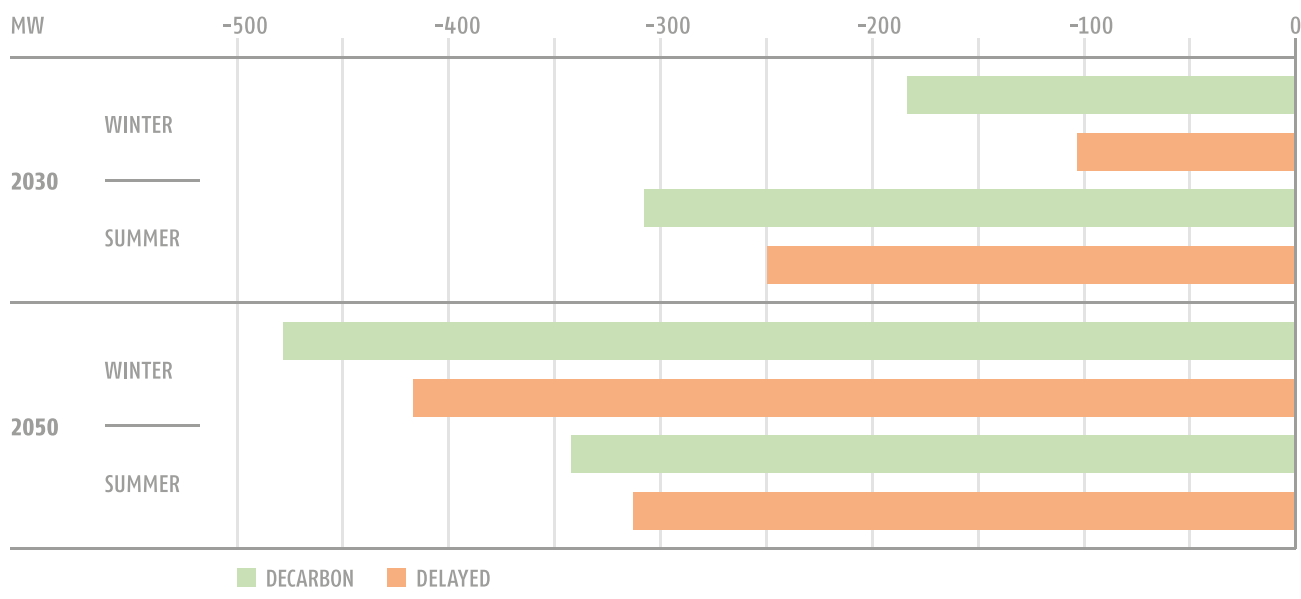
FIGURE 18

LOSS VARIATION
COMPARED TO
THE BASE CASE
IN THE 'DELAYED'
AND 'DECAR-
BONISATION'
SCENARIOS
(MW, NEGATIVE
VALUES
INDICATE LOSS
REDUCTION)

## 5.7 Macroeconomic impacts

A 'baseline' scenario which differs from the 3 core scenarios was constructed for the macroeconomic analysis, to serve as a basis for comparison. The 'baseline' scenario assumes that only power plants with a final investment decision by 2016 are built and that investment rates in the sector remain unchanged for the remaining period. No decarbonisation targets are set in this case, and no additional renewable support is assumed compared to currently existing policies. The 'baseline' scenario assumes lower levels of investment than the 3 core scenarios.

The 'baseline' scenario suggests that after an initial stronger performance at around 3% per annum, economic growth in the SEERMAP region slows down to 1.6% by 2020-2030 as countries converge towards the EU average in terms of GDP per capita. Individual country results differ substantially from the average region-wide tendency; 5 smaller economies grow above 2% per annum on average over the whole projection horizon, while the rest, most notably Greece and Bulgaria, have much weaker performance of 1.5%. Employment is projected to stagnate in most countries, with the exception of Greece and Macedonia. After significant efforts to improve the fiscal balance, both public and external debt could stabilise at around 60% of GDP.

In the 'baseline' scenario household electricity expenditure relative to disposable income is projected to increase from the current 2.5% to around 3%, partly because the growth of electricity prices causes a growth in expenditure which is higher than the expansion of households real disposable income. Household electricity expenditure to income will increase in 8 out of the 9 countries in the region, while it will decline visibly in Greece.

Government and external debt will remain broadly unchanged in most countries that are characterised by a low initial debt level. Nonetheless there are some exceptions: both public and external debt will decline substantially in Greece from exceedingly high initial levels. Additionally, there is a sizable decline in external debt in Montenegro, with more moderate declines registered in Bulgaria, Macedonia, Romania and Serbia. In terms of public debt, in addition to Greece, Albania, Bosnia and Herzegovina, Bulgaria and Montenegro also show a moderate decline.

**FIGURE 19**
GDP AND
EMPLOYMENT
IMPACTS
COMPARED WITH
THE 'BASELINE'
SCENARIO

All three core scenarios imply a moderate increase in investment compared to the 'baseline' scenario. Even in the most investment intensive periods, the net additional investment is below 0.5% of GDP. In the case of the 'no target' scenario, most of the additional investment is concentrated before 2025 compared with the 'baseline' scenario, while in the 'decarbonisation' scenario the intensive period starts after 2020 and remains relatively consistent. In the 'delayed' scenario there are two investment peaks: the initial period and from 2030 onwards.

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

The three core scenarios suggest moderate macroeconomic gains with GDP increasing by 0.7-1.5% over the whole projection horizon. Long term (2046-2050) gains are higher, in the range of 1-2.5%. The gains are highest in the 'delayed' scenario and lowest in the 'no target' scenario. These differences primarily reflect the size of the investment efforts compared to the 'baseline' scenario. Long term GDP gains in the 'decarbonisation' and 'delayed' scenarios result from two sources; the additional investment raises the level of productive capital in the economy and the newly installed, mostly foreign technologies increase overall productivity.

Employment gains are much more muted, growing by less than 0.3% even in the scenarios with the highest GDP gains. The lower employment gains compared to the GDP effect are explained by two factors: (i) the energy investments are relatively capital intensive and (ii) the initial employment gains are translated into higher wages in the longer term, as labour supply remains the same across scenarios.

Similarly to the 'baseline' scenario, country results vary significantly. Effects tend to be larger for smaller economies (Bosnia and Herzegovina, Kosovo* and Montenegro), and less pronounced for larger ones (in particular Greece and Romania). Additionally, the

**FIGURE 20**
GDP EFFECTS
AT THE COUNTRY
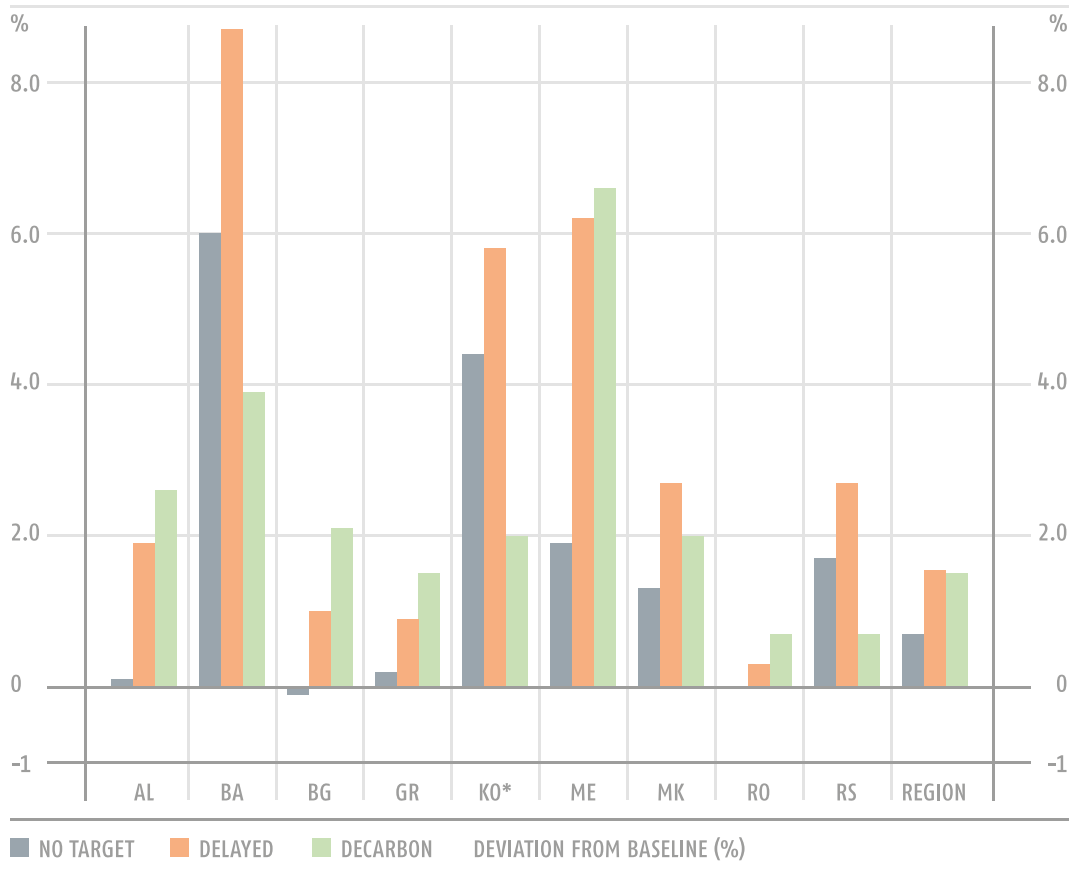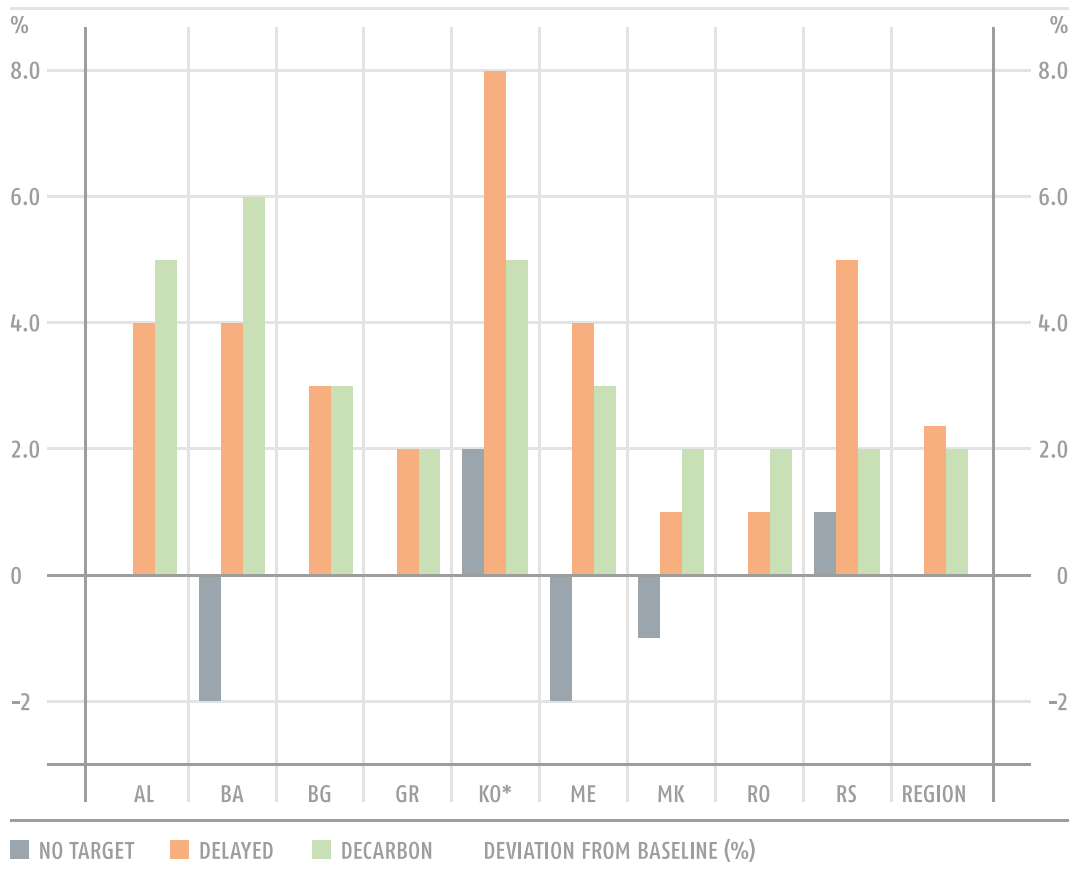LEVEL IN
THE CORE
SCENARIOS
(2017-2050
AVERAGE)



**FIGURE 21**
EMPLOYMENT
EFFECTS AT
THE COUNTRY
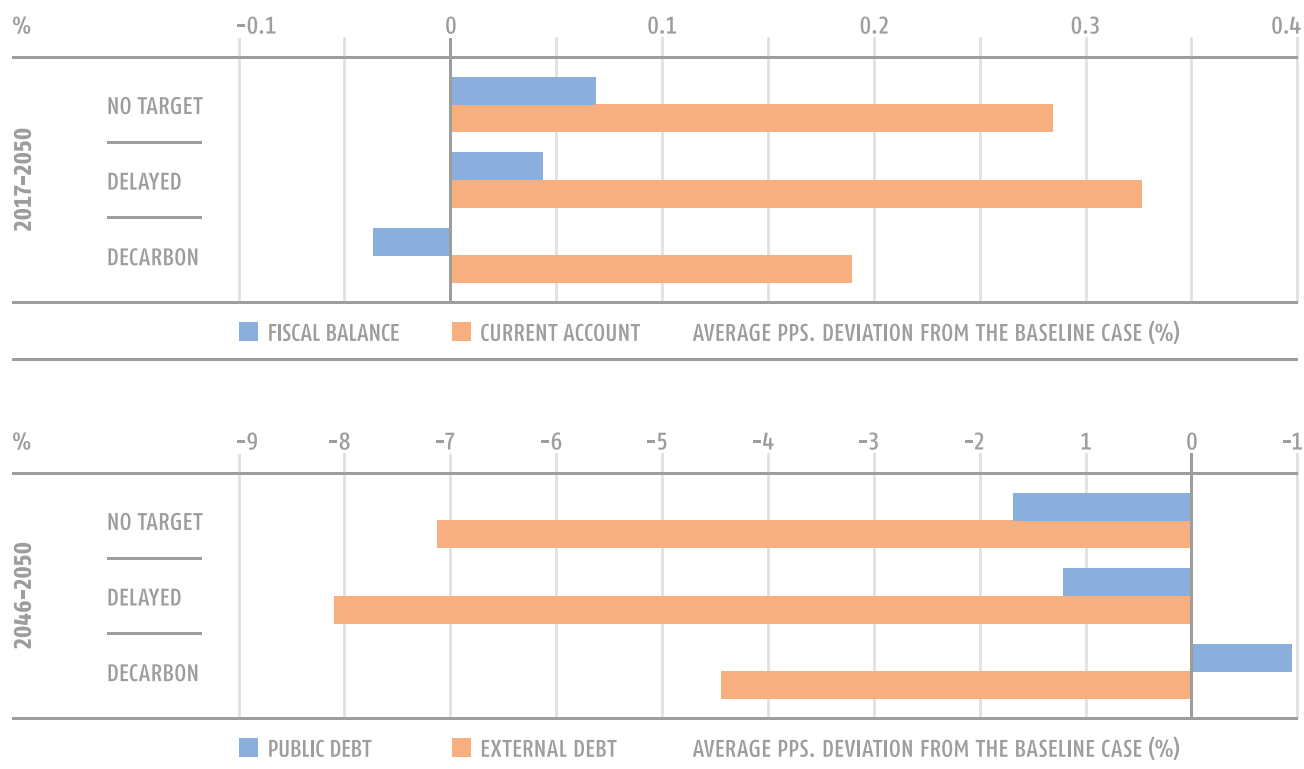LEVEL IN THE
CORE SCENARIOS
(2017-2050
AVERAGE)

**FIGURE 22**
PUBLIC AND
EXTERNAL
BALANCES AND
DEBT IMPACTS
COMPARED WITH
THE 'BASELINE'
SCENARIO

sequencing of the macroeconomic gains are not consistent across scenarios: 5 out of the 9 countries experience the largest effects under the 'decarbonisation' scenario, for the rest of the countries the 'delayed' scenario shows the most gains. Additionally, the relative size of the GDP effect in the 'no target' and 'decarbonisation' scenarios vary from country to country. These differences depend on the relative size of the different types of energy investment as well as their implementation horizon.

Similarly to GDP gains, the 'decarbonisation' scenario also has the strongest employment effect in 5 out of 9 countries. This is mainly due to the fact that renewable deployment (most notably PV) has much higher employment intensity than traditional fossil plants.

The macroeconomic vulnerability calculation captures how the additional investments contribute to the sustainability of the fiscal and external positions of the country. This is analysed according to 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 time horizon. This approach is consistent with the fact that debt is accumulated from past imbalances.

The three core scenarios generally decrease macroeconomic vulnerability as external debt tends to decline. Public debt decreases in the 'no target' and the 'delayed' scenarios, and only slightly increases in the 'decarbonisation' scenario. Nonetheless, overall effects are small; even the decline in external debt is hardly above 8% of GDP at the regional level.

The improvement in the external debt position is primarily the result of lower net electricity and gas imports for most countries. This effect is reinforced by higher GDP, which, ceteris paribus, decreases the debt to GDP ratio and hence the effective burden of the debt service.

Public debt positions are affected by two main factors. First, intensive fossil investments raise $CO_2$ related budget revenues in the 'no target' and 'delayed' scenarios, while
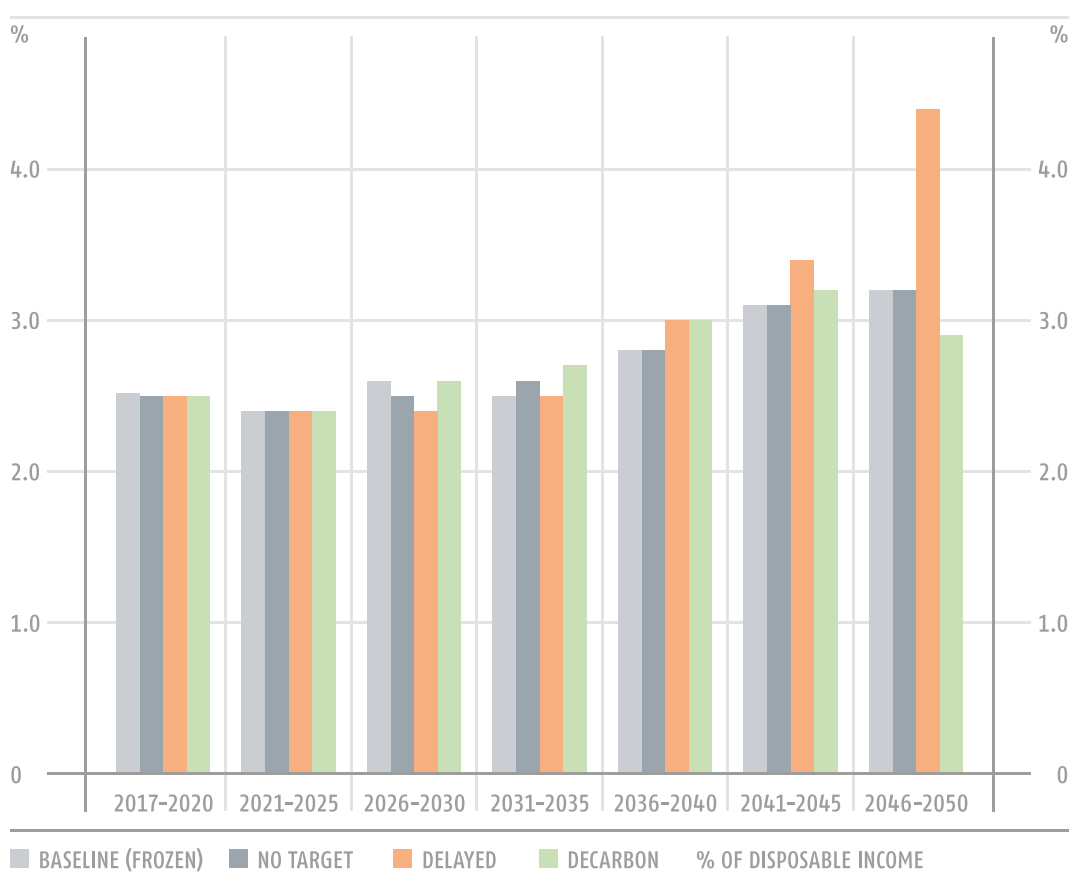
less fossil investment decreases such revenues in the 'decarbonisation' scenario. Second, higher GDP increases budget revenues and decreases public debt by a simple scale effect (lower effective debt service). In the 'no target' and 'delayed' scenarios all of these effects lead to a lower level of public debt than in the 'baseline' scenario. In the 'decarbonisation' scenario, the effect of lower $CO_2$ revenues has a slightly greater effect on the fiscal position than higher GDP has on fiscal revenues and public debt. However, there are some exceptions: in the case of Bulgaria and Romania, all scenarios will lead to lower $CO_2$ revenues, more public debt and consequently a worse fiscal balance.

Country results vary again, to a significant extent. Regarding the effect on the external debt positions, given that intensive investments for domestic energy production (and renewable technologies in particular) decrease net energy imports in most countries, the current account improves, and hence external debt is lower. This effect is reinforced by higher GDP which scales down the debt level. However, for Bulgaria in some scenarios net energy imports increase. Hence the current account deteriorates, and the higher GDP level cannot compensate for this effect.

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.

Generally, the average ratio of household electricity expenditure to disposable income at the regional level does not deviate substantially from the 'baseline' scenario. However, in the 'delayed' scenario the end of the projection horizon is characterised by around 35% higher expenditures caused by higher renewable subsidies during the period of 2046-2050. This effect is mitigated to a degree by lower wholesale energy prices. In the

'decarbonisation' scenario, electricity expenditure is around 10% lower compared to the 'baseline' towards the end of the modelled time horizon. Finally, there is only a small increase in the 'no target' scenario compared to the 'baseline', reflecting slightly higher real wholesale electricity prices.

# 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 countries in the SEERMAP region can take. We review these findings and suggest some policy relevant insights. **The analysis has uncovered robust findings relevant for all scenarios, from which no regret policy options can be identified.**

**MAIN POLICY CONCLUSIONS**

**Regardless of whether or not countries in the SEERMAP region pursue an active policy to decarbonise their electricity sector, a significant shift from fossil fuels to renewables will take place:**
- Countries in the SEERMAP region will, due to aging power plants, need to replace around 95% of their existing fossil fuel generation fleet by 2050;
- Results show that the replacement of current capacities will result in a large increase of renewable and disappearance of fossil based generation, with the exception of natural gas;
- The renewable share is almost 60% in the 'no target' and more than 80% in the 'delayed' and 'decarbonisation' scenarios in 2050;
- Lignite electricity generation will account for only 3-4% by 2050 in all scenarios, regardless of active renewable policies;
- Natural gas plays a transitional role on the path towards low carbon generation;
- The high penetration of renewables in all scenarios suggests that energy policy, both at the national and regional level, should focus on enabling RES integration;
- High renewable penetration does not compromise regional energy security.

**Decarbonisation is worth it:**
- The 'decarbonisation' scenario demonstrates that it is technically possible to reach decarbonisation targets suggested by the EU 2050 Roadmap in the SEERMAP region due to high RES potential;
- Decarbonisation does not drive wholesale prices up relative to other scenarios with less ambitious RES policies, but on the contrary, it reduces them after 2045;
- The macroeconomic analysis shows that despite the high absolute increase in wholesale electricity prices, household electricity expenditure relative to household income will only increase slightly, this increase is unavoidable in the 'no target' scenario as well;
- Decarbonisation reduces the cost of stranded investments by more than 75% from 2.5-2.6 EUR/MWh to 0.6 EUR/MWh in the region as a whole;
- The 'decarbonisation' scenario enables the region to reduce its reliance on imported fossil fuels, in particular natural gas, compared with the 'no target' scenario;

**43**