Accelerated lignite exit in Bulgaria, Romania and Greece

May 2020

Report: Accelerated lignite exit in Bulgaria, Romania and Greece

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The Regional Centre for Energy Policy Research (REKK) is a Budapest based think tank. 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 Centre for the Study of Democracy (CSD) is a European public policy institute with a mission to build bridges between scholars and policymakers. CSD combines research excellence with policy advocacy for piloting social innovation and institutional reforms in Bulgaria and in Europe in a number of areas, most notably energy governance and energy security, economic and legal transition, anti-corruption and security, forensics and criminology, human rights and migration. CSD has published more than 30 policy reports and briefs on energy related topics, such as conventional and green energy governance, decentralization of energy supply, energy efficiency and sustainable energy policies, involvement of consumers, public procurement in energy, energy strategy, diversification and security.

The Energy Policy Group (EPG) is an independent, non-profit think tank on energy and climate policy based in Bucharest, founded in 2014. EPG aims to provide the interested public with evidence-based information and analysis on public policy, energy markets, and strategic planning. EPG has been part of several international research projects on energy markets and strategy in Romania, Southeast Europe and the Black Sea Area. In its current activity, EPG does energy policy research and analysis, consulting, teaching and publishing, as well as specialized events (conferences, workshops, and roundtables) on specific issues in the energy sector.

FACETS S.A specializes in issues of energy, environment and climate and in particular, their complex interdependence and interaction under the influence of technological advances and the demands of sustainability. 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.

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Executive Summary

In light of the ambitious targets of the Paris Agreement and highly ambitious long term decarbonisation goals set by the European Green Deal, a critical question for decision-makers is how to sustain a coal and lignite phase-out that is as swift as possible while also ensuring security of supply, affordable electricity, and a just transition in regions dependent on coal. The aim of this report is to support decision makers in how to implement a timely phase-out of coal by presenting results of analysis on the impact on electricity systems as well as the local economy, and highlighting policy recommendations to deal with potential issues related to compensation, system security and local economic impacts.

The report builds on two main work streams: modelling the impact of the early retirement of some coal and all lignite power plants in the electricity sector in Bulgaria, Greece and Romania; and calculation of the regional and local impacts of an early coal/lignite exit based on NUTS 2 and NUTS 3 level regional data collection.

The modelling of various phase-out scenarios reveals several important conclusions:

- Annual **economic losses of lignite plants are higher if phase-out happens later**, and cumulative losses are even higher. Early phase-out can reduce aggregate losses as some unprofitable plants are closed and utilisation rates (and thereby profitability) of remaining plants increase. As most lignite producers operate with some sort of government support, either explicit or through implicit support regimes, a decrease in profit losses in power plants translates into cost reductions for all of society. Advancing the closure of these plants would mean this support can be reduced significantly.
- As lignite plants are unprofitable, **compensation for power plants in the case of an early phase-out is not needed**. The low utilisation rates of lignite plants resulting from the crisis caused by covid-19 are likely to generate even higher losses for lignite power plants, strengthening the argument that compensation for closures to power plant owners is not required.
- However, **the wholesale price impact of earlier phase-out can be significant, albeit temporary**. The price increase is within the range of 12-23 EUR/MWh depending on the speed of the phase-out and on the country; this effect is felt for a few years. This is one of the most significant costs of an early phase-out.
- The **price impact can be reduced significantly if demand growth is kept in check.** The modelling assumed this could be achieved by implementing end use energy efficiency measures. However, it is likely that the covid-19 epidemic will also achieve a significant reduction in demand compared with what was previously projected by member states. Under a lower demand growth scenario, the temporary hike in wholesale prices can be reduced to 3-12 EUR/MWh, and over the medium term, after about 4-5 years, the price impact of an early phase-out disappears in the lower demand scenarios. By 2030 the scenario with early phase-out and lower demand combined results in a lower wholesale electricity price by 4-11 EUR/MWh than the reference scenario. Careful and urgent planning of significant energy

efficiency measures is needed in electricity end use sectors to ensure that demand does not return to the growth trajectory which was projected before the epidemic.

- In addition to reducing growth in electricity demand, **policy makers can reduce the temporary increase in wholesale prices by implementing more agressive RES deployment**. Two of the main drivers of increasing prices (the carbon price and the increasing price of natural gas) are not relevant for renewables. However, policies specifically targeting vulnerable consumers may be needed as complementary measures.
- The current crisis caused by the epidemic means that a lower demand growth is likely even without energy efficiency measures. Therefore, the price impacts, modelled before the crisis occurred, are unlikely to materialise. **Reduction in demand caused by the crisis, combined with the financing offered by the European Green Deal provide a good opportunity to phase out lignite without broader price impacts.**
- **The phasing out of lignite plants would allow government to reduce financial support to power plants** and use these revenues to invest in renewable energy, energy efficiency or for the protection of vulnerable consumers. Information on current state subsidy levels is not fully available, but is estimated at EUR 450 million in Bulgaria, at close to EUR 900 million in Greece, and EUR 200 million in Romania per year. In addition to decreased government revenues, TSOs can use their increased revenues to decrease electricity prices. The net decrease in total welfare from an early phase-out is relatively small, at EUR 89.8 million, EUR 29.7 million and EUR 12.6 million in Bulgaria, Greece and Romania over the 2020's on average annually. This is low compared with estimated annual government support provided to keep power plants operational.
- **Existing and currently planned natural gas capacities can replace outgoing lignite capacities to some extent**. However, the role of gas power plants varies among countries to a large extent. The overall findings indicate that the role of gas needs to be evaluated in light of other capacities in the system as well as in light of potentially cheaper import opportunities. According to model results, utilisation of gas plants remains relatively low in Bulgaria, questioning the rationale for the level of gas power plant investment that is planned. Some existing trade-offs between investment in gas and renewables also needs to be considered- whereas gas assets may become stranded as carbon prices increase further, this will not happen to RES capacities.
- **Capacity payments should not be used as compensatory measures**, rather, they should be based on the actual relevance of these plants in terms of balancing supply and demand. The modelling of system security impacts of an early coal phase-out suggests that even a very early phase-out does not cause system security issues, questioning whether planned capacity payment measures are really serving their purpose or whether they constitute problematic state aid. Not only do they not serve their purpose but may lead to market distortions and do not bring value to the consumer. They may also lead to lock in unsustainable generation capacity.
- In terms of import dependency, the modelling suggests that **the current import status of countries will change under all scenarios and cannot be credited to coal phase-out alone**. The modelling also shows that the impact of an early phase-out affecting multiple

countries is not at all straightforward. Policy makers are often led to believe that keeping lignite plants in the system can only reduce import dependency. However, while early phase-out increases net imports in Bulgaria, it reduces net imports in Greece. This suggests that if a region-wide early phase-out is implemented, it provides competitive advantages to countries with high RES shares, such as Greece.

- The modelling also demonstrates the **importance of high interconnectivity**. While price differences among the scenarios are around 7-8 EUR/MWh between Greece and Bulgaria at the beginning of the modelled period, and still around 5 EUR/MWh in 2022, after the new GR-BG electricity interconnector comes online in 2023, it disappears entirely for the next 3 years. The two markets do not diverge by more than 1 EUR/MWh later on in either of the modelled years (2023 and 2029). Increased interconnectivity between Greece and Bulgaria also helps avoid high RES curtailment levels in Greece, despite a significant increase in weather dependent RES capacity. Early phase-out increases the utilisation rate of the interconnectors, thus increasing revenues of TSOs and providing them with funding to improve transfer capacities or to reduce consumer tariffs.
- The analysis of the economic impacts in coal regions shows that around **84 000 jobs may be lost** in the coal sector and in other sectors indirectly impacted by the phase-out in the three countries. Therefore, measures to boost regional economies and measures to protect, re-skill and support workers made redundant by the phase-out need to be put in place.
- The analysis also shows that **financial support**, including but not limited to investment, **of around EUR 3.7 billion will be required** in the regions to offset negative impacts on GVA from the coal phase-out in the three countries. Some of this will be required as grants, while productive investment can be made with loans and other financial instruments. Governments need to focus on designing strategies and implementing policies for a just transition.

1. Introduction

On 28 November 2018, the Commission presented its strategic long-term vision for a prosperous, modern, competitive and climate-neutral economy by 2050. The new Commission of Ursula von der Leyen proposed a net zero greenhouse gas emission target for 2050 as part of the European Green Deal package. The proposal for a European Climate Law enshrined the net climate neutrality objective in legislation in March 2020. The Commission's proposal for a Just Transition Mechanism to support regions where the transition to a carbon-neutral economy is most challenging was made in January 2020.

In this new policy context, member states have started to formulate their negotiation strategies. Poland has set out a non-paper on financing climate neutrality calling for additional funding to ensure a just transition, as well as other protective measures such as a border tax adjustment. The covid-19 epidemic has caused shifts in country positions towards weaker climate ambition in the region.

At the same time, the tide has been turning for coal-fired electricity generation. At the global level, the IEA has warned in its World Energy Outlook for 2019 that legacy investment is endangering the achievement of climate targets set out in the Paris Agreement and that an early retirement of a significant portion of coal capacity will be required (IEA, 2019). In the EU, coal generation had already fallen by 30% from 2012 to 2018 and fell another 19% in the first half of 2019 compared with the same period in 2018 as a result of the carbon price increase which started in 2018 and has continued in 2019 (Sandbag, 2019). Half of this generation was replaced by renewables, the other half by natural gas. Current figures indicate that the EU is heading towards a 23% decrease in coal by the end of 2019 (CarbonBrief, 2019). Owing to the changing profitability of coal and negative public opinion, to date an increasing number of EU member states are announcing plans to phase-out coal. The covid-19 epidemic has not lessened the pressure on coal and lignite plants; the reduction in electricity demand has further weakened plant profitability. The epidemic caused a temporary fall in the price of EUAs, but the price has since rebounded.

However, progress on coal phase-out has been uneven among EU member states, with most of the EU member states of South East Europe having ignored the issue of coal phase-out in their draft National Energy and Climate Plans. The decrease in coal-fired generation during the first half of 2019 has also fallen short of that in Western parts of the EU, with coal or lignite-fired generation increasing by 8% in Bulgaria over this period, and decreasing by 16% and 13% in Greece and Romania, respectively. (Europe Beyond Coal, 2019) The Commission has raised the issue of the planned use of coal in electricity generation and its potential (in)compatibility with decarbonisation in its recommendations to the submitted NECPs in the case of Bulgaria and Romania. (European Commission, 2019a, European Commission, 2019b, European Commission, 2019c)

Greece has since made impressive progress in increasing the climate ambition of its NECP, with only 660 MW coal remaining in the electricity system after 2023 proposed in the new version of the NECP. However, similar progress was not made in Romania and Bulgaria. In contrast, these two countries are using various support mechanisms to help their coal and lignite-fired state-owned plants to purchase EUAs. This support is likely to be deemed illegal state aid and will result in a wasteful use of public funds for obsolete power plants instead of support to economically and environmentally attractive alternatives.

The critical question for decision-makers is how to sustain a coal and lignite phase-out that is as swift as possible while ensuring security of supply and an acceptable electricity price and avoiding high transition costs in coal regions. The aim of this paper is therefore to support decision makers in the above. We consequently take a closer look at how to implement a timely phase--out of coal by presenting results of our analysis on the impacts on electricity systems as well as the local economy, and highlighting policy recommendations to deal with potential issues related to compensation, system security and local economic impacts.

The project had two main work streams: modelling the impact of the early retirement of some coal and all lignite power plants in the electricity sector in the three countries covered, Bulgaria, Greece and Romania, and calculation of the regional impacts of an early coal/lignite exit based on detailed disaggregated data (at NUTS 2 and NUTS 3 level) for the regions in focus.

2. Regional results

2.1 Modelled scenarios

Since the aim of the modelling was to assess the impact of early (coal and) lignite phase-out, a Reference scenario and four early phase-out scenarios were modelled. In the former all lignite plants finish operation in the year according to the latest available information. In the early phase-out scenarios they close 2, 4, 6 or 8 years earlier than in the Reference. The planned dates of decommissioning are contained in Table 46 in Annex 3.

For all five scenarios three types of sensitivity analysis were carried out. The first assessed the impact of a change in RES levels and modelled a lower RES path. The second tested the impact of the carbon price on results, assessing the impact of both a lower and a higher CO_2 price trajectory. The third assessed the impact of a lower electricity demand trajectory. It is currently not known how electricity demand will rebound after the covid-19 epidemic, but it is likely that a lower than reference demand scenario is more reflective of expected demand developments over the next few years than the demand projections that were prepared before the epidemic.

Information on RES potentials and RES use by scenario was taken from the Green-X model and its database, respectively. The database includes estimates of *long-term technical RES potentials* based on several factors including the efficiency of conversion technologies as well as GIS-based data on wind speed and solar irradiation, and are reduced by land use and power system constraints.[1] The actual *RES* use, i.e. the exploitation of these potentials, differs between scenarios. As illustrated in Table 1, the modelled 2030 RES share in the electricity sector was set either in accordance with the countries own planning as postulated in their draft National Energy and Climate Plans (NECP), or in line with the European Commission's perception of how to distribute the efforts for reaching the binding EU 2030 RES target (32%) across MSs, named as EC benchmarks.[2] For Bulgaria and Romania the modelled 2030 RES use in the Ref RES scenario reflects the EC view on the way forward whereas the Low RES scenario indicates the countries' own view as postulated in NECPs. In Greece the

[1] Moreover, it is also assumed that the long-term potentials can only be achieved gradually, with renewable capacity increases restricted over the short term, reflecting the impact of non-cost barriers like permitting and grid access. Capacity factors of RES technologies were based on historical data over the last 5 to 8 years depending on the technology.

[2] Annex II of Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action introduces a methodology for establishing benchmarks concerning the national contributions for the share of energy from renewable sources in gross final energy consumption in the 2030 context at EU level. This approach follows an integrated concept that takes into account the differences in economic development, the potential for cost-effective RE deployment and the interconnection level in the European Network of Transmission System Operators for Electricity (ENTSO-E) across the EU and its Member States, respectively.

opposite occurs: here national RES planning is more ambitious than EC benchmarking, and is consequently reflected in the reference (Ref RES) scenario.[3]

Table 1 Scenario-specific 2030 RES use in Bulgaria, Greece and Romania - comparison with NECPs and EC Benchmarks

Country	Modelled RES(-e) share	RES(-e) target 2030
Bulgaria	22.5% (Reference RES) 17.2% (Low RES)	18.0% ... 26.9% (EC Benchmark*) 17% (NECP 1st draft) 26.99% (NECP 2nd draft)
Greece	48.5% (Reference RES) 45.7% (Low RES)	43.8% ... 52.8% (EC Benchmark*) 56% (NECP 1st draft) 61% (NECP 2nd draft)
Romania	48.5% (Reference RES) 39.8% (Low RES)	48.7% ... 58.3% (EC Benchmark*) 39.6% (NECP draft)

*Note: Expressed ranges reflect differences in sector allocation, either done in accordance with the allocation used in NECP or with the status quo (2017)

2.2 Modelling Results

The critical question for decision-makers over the next decade is how to sustain a coal and lignite phase-out as swiftly as possible while also ensuring security of supply, system adequacy, and an acceptable electricity price. The modelling provides some conclusions in this respect as early phase-out of lignite capacities was modelled and impacts on the wholesale electricity price, security of supply and profitability of power plants were assessed.

The modelling took into consideration planned capacity developments in Bulgaria, Greece and Romania. The Reference scenario reflects planned coal and lignite power plant closures as indicated in various plans and documents, while the REF-2, REF-4, REF-6 and REF-8 scenarios reflect power

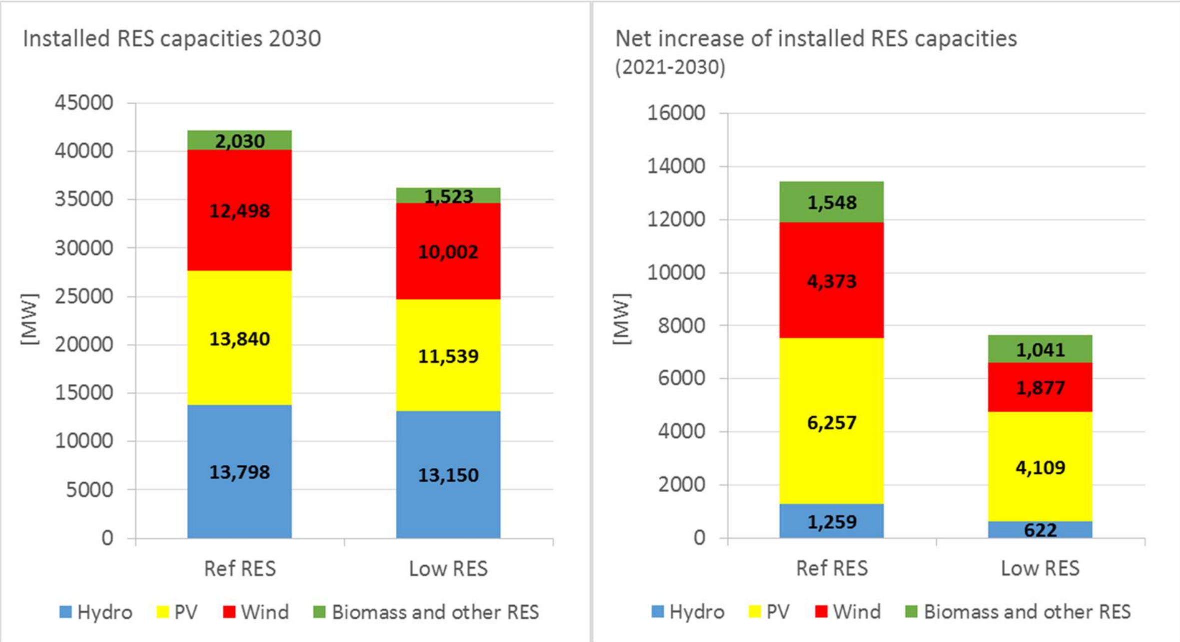
[3] The latest 2030 NECP RES target for Greece can be classified as very ambitious, exceeding by far the EC benchmark. In the modelling a more conservative assumption was made in the Reference scenario which is within the upper range for the RES share in electricity according to EC benchmarking: instead of 56% only a 48.5% RES share is presumed for 2030.

plant closures that are brought forward by 2, 4, 6, and 8 years, respectively.[4] The assumed power plant closures focus on lignite power plants, as planned coal power plant closures are generally beyond the 2030 horizon and therefore a less radical phase-out is modelled for the coal plants.

In addition to capacity retirements, new fossil fuel capacities which are included in national plans were input into the model exogenously, and **RES capacity levels** were modelled with Green-X. The latter reflects higher RES capacity levels for Bulgaria and Romania than included in the draft National Energy and Climate Plans of these countries in the reference scenario (Ref RES). The reason for this is that feedback from the Commission on first NECP drafts of these countries indicated that RES shares in the NECPs were insufficient. For Greece, the assumed RES capacity is close to, but slightly lower than the figure contained in the latest NECP. The assumption with respect to RES in the reference (Ref RES) scenario in the three countries was an approximately 13.4 GW net increase in capacity on current levels until 2030, reaching a total capacity of 42.2 GW. The capacity shares of wind, solar and hydro are close to equal in region in this scenario, while the biomass capacity is significantly lower. In the Low-RES sensitivity analysis, a significantly lower RES uptake is assumed compared to the reference (Ref RES). Here the net increase between 2020 and 2030 is 7.6 GW, corresponding to a cumulative RES capacity of 36.2 GW in 2030. In the Low RES scenario solar PV dominates the market post-2020, followed by wind and biomass.

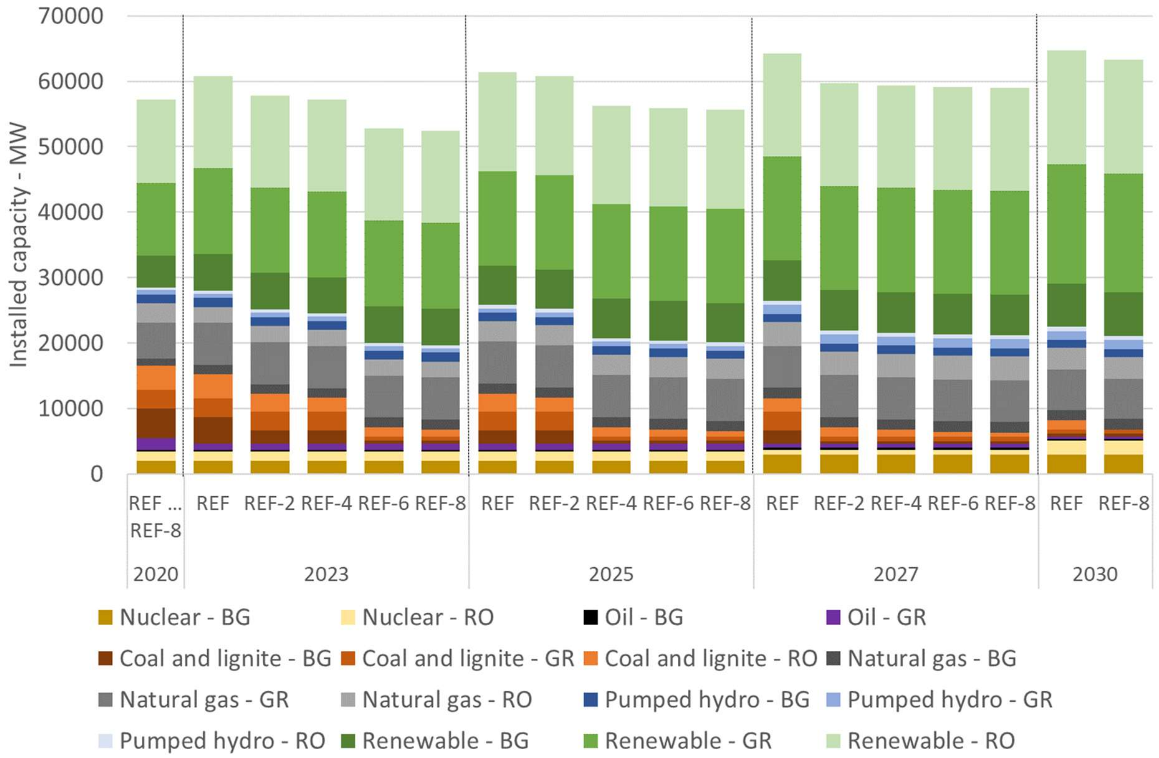
[4] The modelling exercise was carried out before the new National Energy and Climate Plan of Greece became available. in late November 2019. There has been a significant move towards early phase-out of lignite plants in Greece in the new NECP. As a result, all analysed scenarios reflect phase-out which is less ambitious than the current NECP. Nevertheless, the modelling and the resulting policy conclusions have important lessons for how to implement a just transition in Greece.

Figure 1 Total installed RES capacity (left) and RES capacity increase (right) in the reference (Ref RES) scenario and low RES sensitivity analysis in 2030 in Bulgaria, Greece and Romania



The resulting **capacity mix** in the different scenarios (REF to REF-8) is depicted in Figure 2. The figure shows similar capacity levels across the different scenarios except for coal and lignite capacities. The base year for the modelling is 2018, therefore the results shown for 2020 are modelled results. The reason is that the new fossil fuel capacity input into the model exogenously based on national plans is sufficient to replace the outgoing capacity and therefore the model does not (endogenously) build new generation capacities in either of the scenarios. However, utilisation rates of power plants differ between different scenarios, thus the electricity mix will not be the same in all scenarios.

Figure 2: Total electricity generation capacity in Bulgaria, Greece and Romania in all scenarios



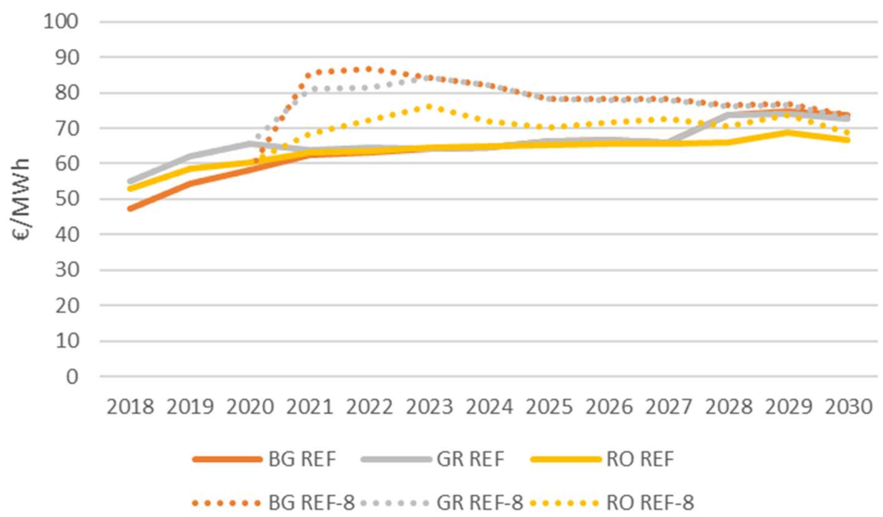
As indicated by the capacity developments shown in Figure 1, the strong **uptake of renewables** in the past decade is maintained in the reference scenario. Electricity from renewables would then achieve a share in gross electricity consumption of 42.3% by 2030 at the regional level, corresponding to an increase by approximately 9.1 percentage points compared to today (2020). A closer look at the RES generation mix shows that hydropower will lose its dominance by then thanks to the strong uptake of solar PV and wind, and strong generation increases also for biomass and other RES technologies.

Changes in the RES technology mix are less pronounced in the Low-RES scenarios, reflecting a pessimistic viewpoint on future RES developments in accordance with national planning (as postulated in NECPs) in Bulgaria and Romania. These scenarios represent only a small increase in RES share in electricity demand in the years to come: from 33.2% in 2020 to 36.3% by 2030.

Wholesale prices increase in all three countries in all scenarios. The increase is driven by two main trends. In the reference case prices are driven up by the increasing fuel costs (natural gas price) and the increasing carbon value assumed in the scenarios. This market driven impact is significant: the present 50-55 EUR/MWh wholesale price level rises to 65 EUR/MWh level by 2027 and further to 75 EUR/MWh by 2030 in the Reference scenario. This later increase is more pronounced in Greece and Bulgaria, while Romania faces a more limited price increase, due to its lower level of lignite capacities, somewhat lower natural gas prices and the stronger connection to the Central European electricity markets.

A further (temporary) increase in prices comes from the phasing out of lignite capacities. The impact of the phase-out becomes stronger with more stringent (earlier) phase-out assumptions. The REF-8 scenario which brings forward lignite phase-out by 8 years results in a price increase in the years 2021-2024 in the range of 12-23 EUR/MWh compared with the reference scenario; this impact stays in the system for several years but weakens over time. Less ambitious scenarios, e.g. 2 or 4-year early retirement result in lower price impacts both in terms of their level (below 15 EUR/MWh) and also in duration, with significant impact limited to the period 2024-2027. The price impact fully disappears by 2028-2030, as most lignite plants would have been closed down by then in the reference scenario or would have very limited market shares and therefore no real impact on prices.

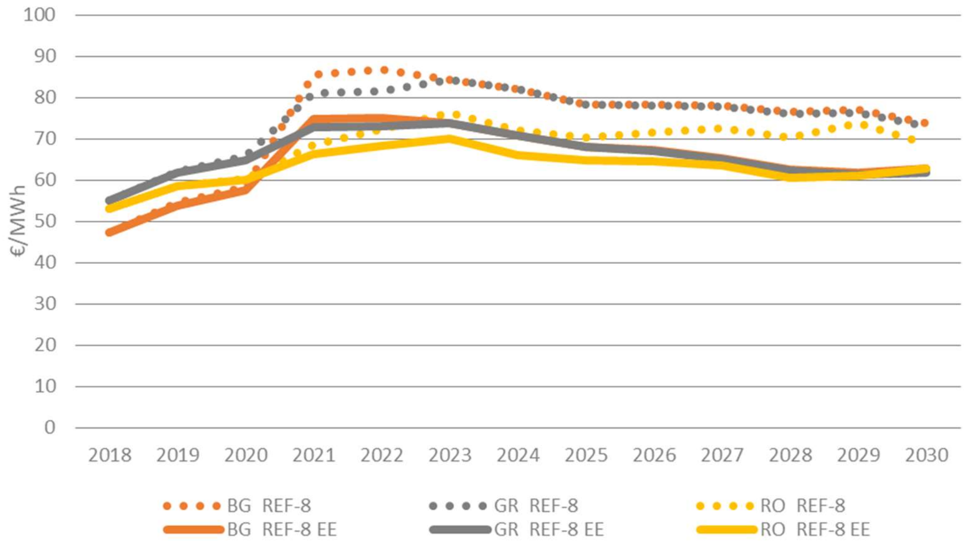
Figure 3: Wholesale price impact of an ambitious phase-out (REF-8) in the modelled countries



Although impacts on end-user prices may be significant as a result of the wholesale price increase, the scenario modelling also identifies instruments which can reduce these effects.

The most important instruments are policies targeting electricity demand growth. Since the reference scenario demand projections were made before the covid-19 epidemic, it is likely that this scenario depicting reduced demand will better represent demand developments over the next few years than projections which were made before the covid-19 epidemic. A sensitivity analysis was prepared where instead of assuming demand in line with national documents, it was assumed that demand would be consistent with the 32% RES and 32.5% EE targets for 2030 modelled using PRIMES. (European Commission, 2019d) More effective energy efficiency policies can limit electricity demand growth, and in turn can reduce the projected price impacts. The price impact can be reduced significantly if demand growth is kept in check. The temporary hike in wholesale prices can be reduced to 3-12 EUR/MWh, and over the medium term, after about 4-5 years, the price impact of an early phase-out disappears if energy efficiency measures are implemented. By 2030 the scenario with early phase-out and lower demand combined results in a lower wholesale electricity price by 4-11 EUR/MWh than the reference scenario. This can be seen in Figure 4.

Figure 4: Wholesale price impact with lower demand growth



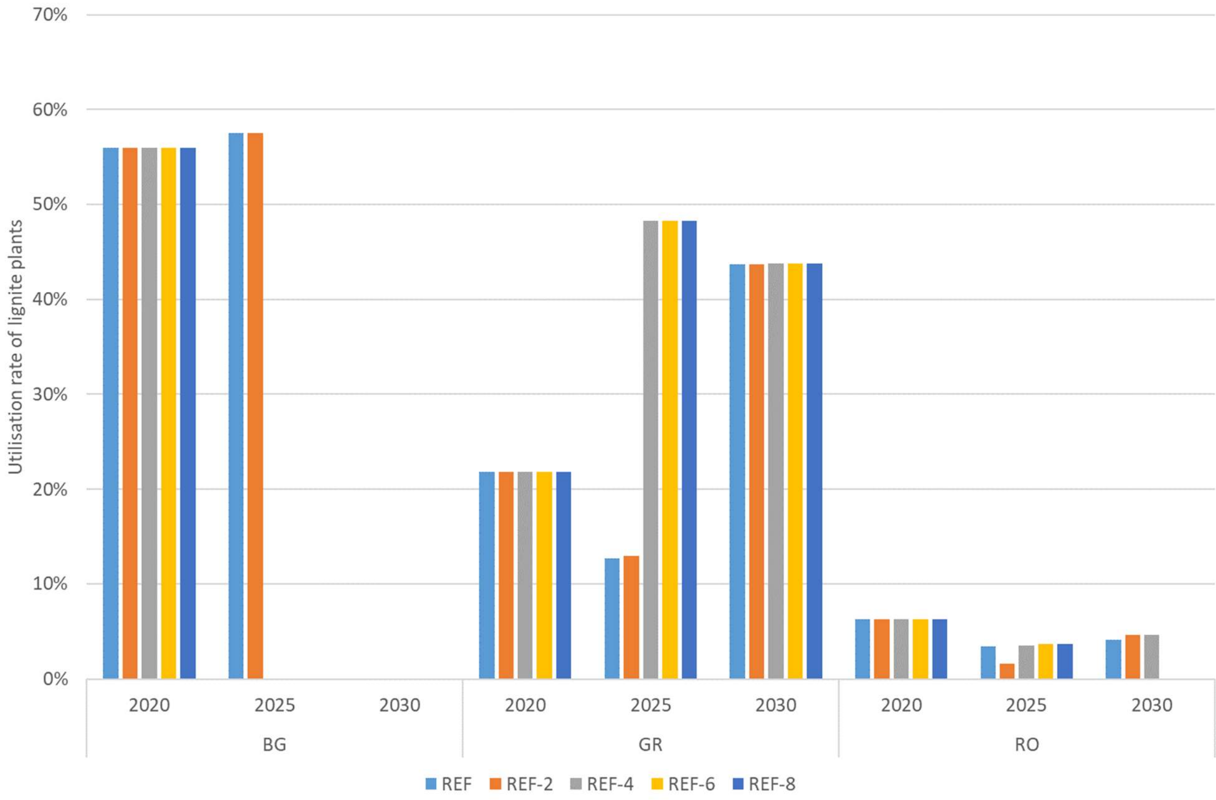
Higher RES deployment levels could also limit the projected wholesale electricity price increases of the more stringent lignite phase-out scenarios, although the modelling shows that RES support for new capacities, although low, is still required in all three countries until 2030. Yearly RES support need is calculated as the price differential between the LCOE cost of a renewable technology and the respective production weighted average wholesale electricity price.

What happens as a result of early phase-out in remaining power plants in the system is crucial. As mentioned above, the model does not build new capacities as the exogenously input capacities are sufficient to satisfy demand. Therefore, it is interesting to see how **utilisation rates** in remaining coal and lignite plants change, as this affects their profit margin, and also whether gas and renewable capacities can replace coal and lignite power plants which are shut down just by increasing utilisation rates, without further investment.

Due to their inherent characteristics related to high investment costs and fixed O&M costs, lignite plants are generally utilised as base load plants, with utilisation rates generally above 60%. Plants which still need to recover investment costs become uneconomical if their utilisation rates fall below 50% over the long term, and assuming electricity only markets, as capital costs and fixed operation and maintenance costs need to be recovered on reduced running hours. Plants which have already recovered their initial investment cost and only need to cover O&M costs with revenues may operate at 50% utilisation rates without losses. However, utilisation rates below 35% imply that plants need to be run in a cycling (rather than base load) operation, requiring more frequent start-ups and ramping, which deteriorates not only the economics of the power plants but also their reliability and asset lifetime. Even for plants which have recovered their investment costs, utilisation rates of 35% or below will mean mothballing as income from product markets becomes insufficient.

Lignite plants in Greece and Romania are in the third, very low utilisation rate category already in 2020-2025 according to model results. This means that in electricity only markets, these plants are not economically viable. Bulgaria has a different situation; utilisation rates are higher mainly due to the lower lignite prices compared to the neighbourhood countries. Interestingly, in the case of Greece earlier phase-out results in improved utilisation rates for the remaining lignite plants, as the fewer plants in the system find better opportunities for their production in the market.

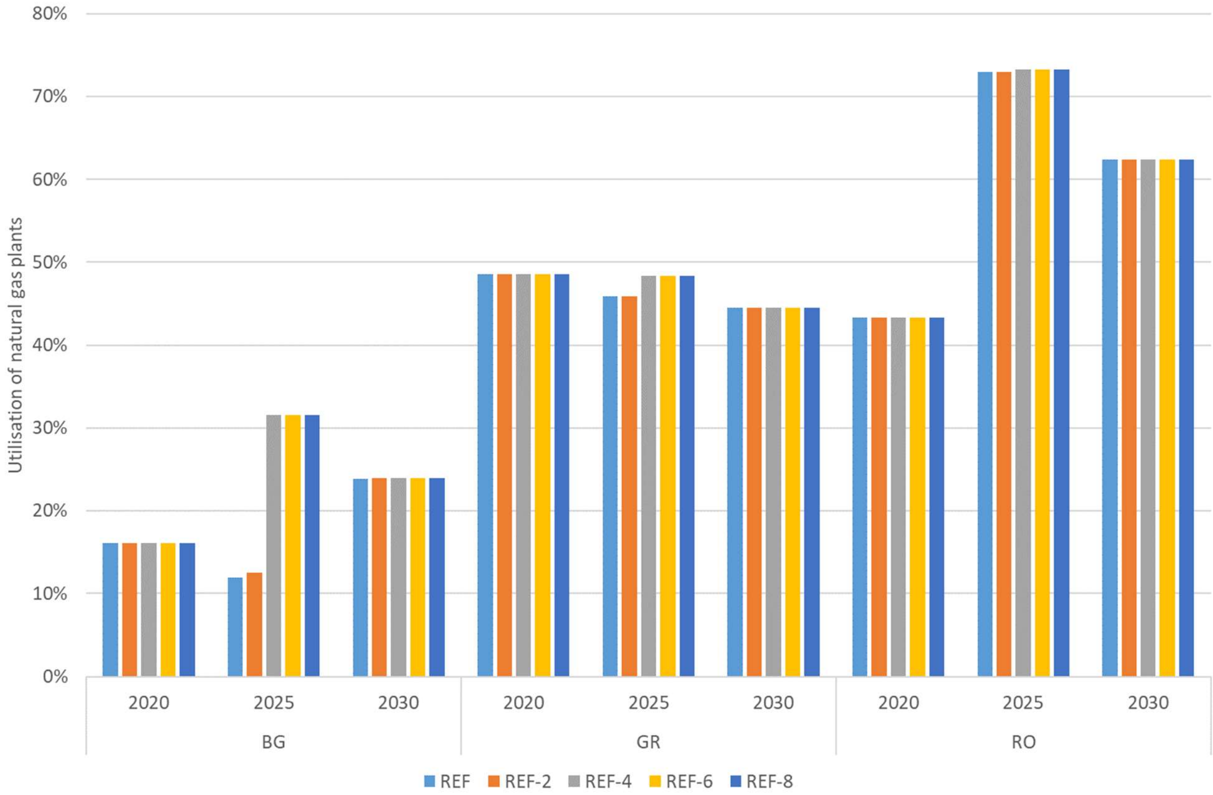
Figure 5 Utilisation rates of lignite power plants in the region, in 2020, 2025 and 2030



Natural gas power plant profitability in general shows less sensitivity to utilisation rates. Due to their relatively smaller investment costs compared to coal and lignite fired plants, gas fired units can be utilised economically even at lower rates. In addition, most gas plants are suitable for frequent start-ups and ramping, which means they usually take the role of mid or peak load plants. A second important feature of natural gas plants is their much lower emission factor compared to the coal and lignite units, as they emit less than half of the CO_2 that coal units produce to generate one MWh of electricity. This also means that with increasing carbon prices in the ETS sector, natural gas will gain higher share, as they will substitute more and more coal-fired generation due to their relatively lower carbon price impact. This happens both in short term dispatching, as well as in longer term operation, as more coal generators will close down due to the economic impacts of increasing carbon prices.

The scenario results confirm this development in Bulgaria; earlier phase-out policies would create a market for higher natural gas fired generation. In Greece and Romania this trend is not observed, due to the stronger RES uptake, which leaves a smaller market niche for gas-fired power plants.

Figure 6 Utilisation rates of natural gas power plants in the region, in 2020, 2025 and 2030



The analysed region has cross-border connections with non-EU member states (countries in the Western Balkans and Turkey) as well as with the Central European EU markets (through the Romania-Hungary interconnector). As many neighbouring countries do not apply carbon taxation in their electricity system, their cost advantage changes the volume and direction of trade, due to the changing competitiveness of electricity generation. The relative carbon intensity of the neighbouring EU countries also influences trade flows in the region. As a result of changes in the market environment, Bulgaria experiences a shift from its current net exporter position to electricity importer in the next decade, while Greece could significantly reduce its imports due to the considerable increase in RES generation. Romania is projected to be in a small net import position over the next decade. This is a very robust pattern in the region, a very strong coal phase-out policy (REF-8) does not change the direction of trade of the countries, but the level of imports and exports do change. Bulgaria does have significantly increased net imports in 2025 in early coal phase-out under REF-8, and somewhat counterintuitively, Greece has lower net imports under an early coal phase-out scenario in the mid-2020's. This latter result indicates the competitive advantages conferred by a high share of RES with zero marginal cost.

Table 2 Net imports in BG, GR and RO in 2020, 2025 and 2030 under the REF and REF-8 scenarios

Net import (GWh/y)	REF			REF-8		
	2020	2025	2030	2020	2025	2030
BG	-7 609	3 938	10 231	-7 609	8 766	10 216
GR	12 405	7 042	3 100	12 405	5 637	3 091
RO	2 534	1 649	3 833	2 534	2 007	4 399

The utilisation rates and wholesale price trends predict that the financial situation - calculated as revenues minus variable and fixed operating costs - of the 'surviving' lignite power plants that remain in the system would improve with stronger phase-out policies. This is confirmed by the results, as the stronger the phase-out scenario, the higher the NPV of profits for the lignite plants. However, we observe that in all scenarios the sum of lignite plant profits are negative. Economic losses in the electricity systems are reduced for the generators with more stringent lignite phase-out plans but profits do not turn positive.

Figure 7 Net present value of profits from lignite-based power production in the region, 2018-2030

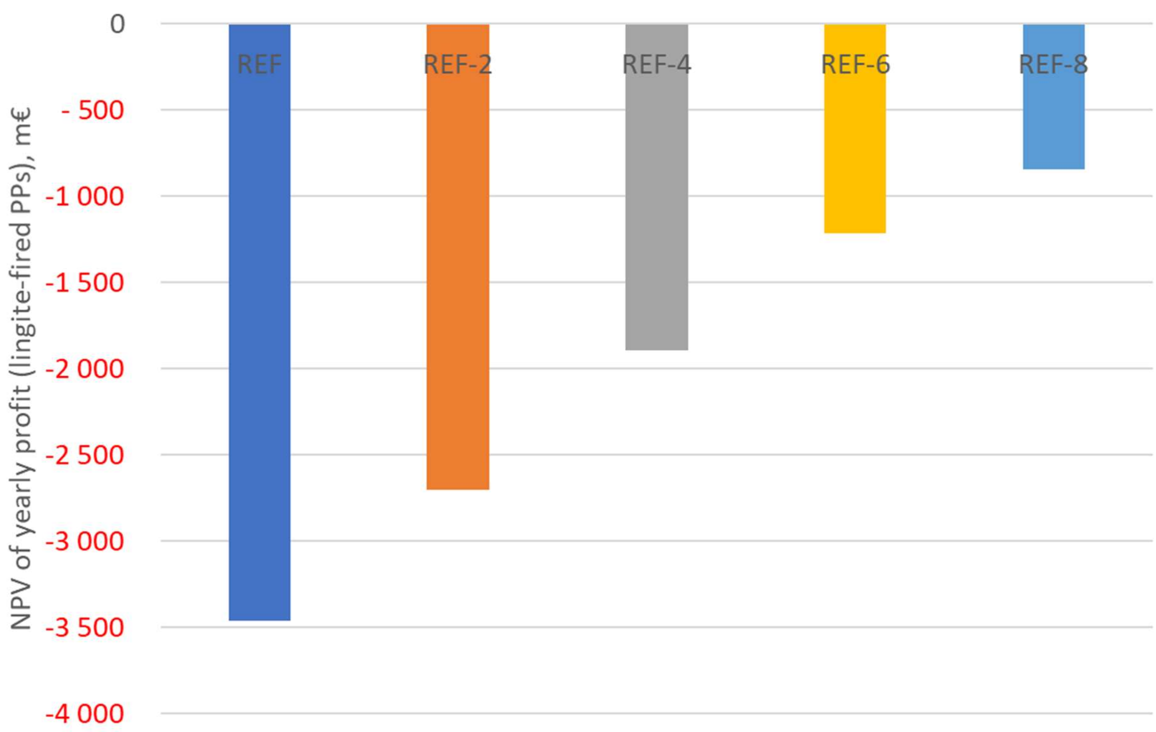
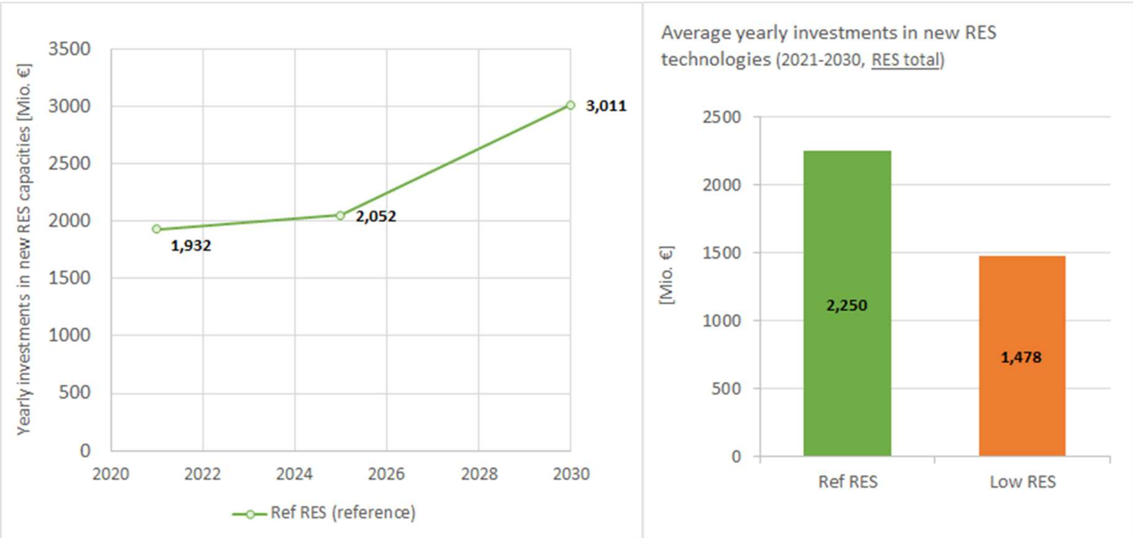


Figure 8 provides further insights on the **necessary investments in new RES capacity** for both underlying RES deployment paths: in the reference scenario (Ref RES) one can see a dynamic upward trend in RES investments, increasing from about 1.9 billon EUR per year today (estimate for 2020) to more than EUR 3 billion by 2030. Average annual RES investments amount to EUR 2.3 billion in the Ref RES scenario whereas only 66% of that would materialize in the Low RES scenario.

Figure 8 Development over time (left) and average (right) of yearly investment in new RES capacity, 2021-2030



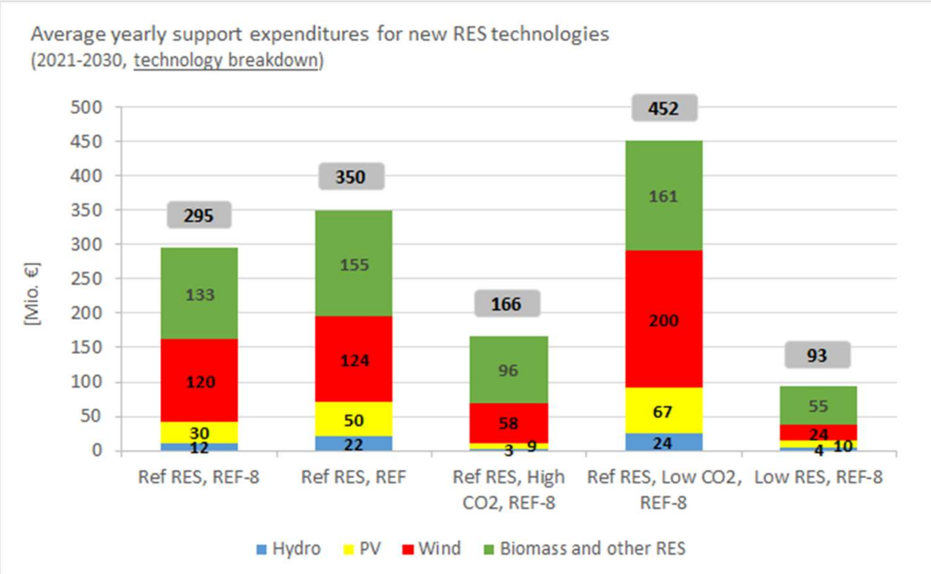
The need for public **RES support** or, more precisely, the RES-related public support expenditures[5], here counted towards reaching the targeted 2030 RES deployment in the electricity sector, is strongly dependent on developments in the wholesale electricity market. Any increase in electricity prices leads to a decline of required support levels and of corresponding support expenditures, and vice versa. The increase in wholesale prices caused by an earlier phase-out of coal would consequently be partly compensated by a decline of support expenditures for RES. This interrelationship between RES support and electricity price trends is apparent from Figure 9, which shows the outcomes of the sensitivity analysis with respect to average yearly support expenditures for new RES installations in the forthcoming decade. RES support expenditure is most sensitive to carbon price trends: in the high CO_2 price scenario (Ref RES, High CO_2, REF-8) support expenditure is cut to almost half compared to default CO_2 prices (Ref RES, REF-8) whereas in the low CO_2 price variant (Ref RES, High CO_2, REF-8) an increase by more than 50% (compared to default CO_2 prices) is observable.

[5]Note that support expenditures reflect the difference between total remuneration and the market value for the generated electricity, multiplied by the amount of electricity generated over a certain time period.

In the Reference scenario, support stays at very low levels, below 1.5% of the wholesale prices in the case of Bulgaria, below 2.5% in Greece, and below 5.5% in case of Romania on average between 2021 and 2030. The higher CO_2 prices would mean competitive advantage for natural gas plants, and an increase in wholesale electricity prices.

A significantly *lower RES uptake* as presumed in the LowRES scenario (Low RES, REF-8) would also cause a decline in support expenditures, due to reduced RES volumes. However, it would also cause an increase in wholesale electricity prices due to the higher use of fossil generation options which operate at higher marginal cost. This impact on consumer prices is ranges from 0.1 EUR/MWh (in Bulgaria under the Ref RES & High CO_2 scenario) to a maximum 4.8 EUR/MWh (in Romania in the Ref RES & Low CO_2 scenario), with averages around 0.5 to 2.1 EUR/MWh across all assessed countries.

Figure 9 Average yearly support for new RES capacity, 2021-2030



The assumed RES investments and planned new gas fired installations in the region can help to maintain **system adequacy** over the next decade. The adequacy modelling carried out with the EPMM unit commitment model shows that reserve capacity needs can be maintained, and sufficient level of spinning and non-spinning reserves stay in the system in the assessed three countries even in the more ambitious phase-out scenarios. As a minimum, 5% reserve capacity is available compared with electricity consumption in both downward and upward regulation in all three countries. The other assessed indicator was energy not supplied (ENS), which showed no increase in the assessed two years (2023 and 2029) in the case of phase-out, as the interconnection levels, new RES and gas fired capacities were sufficient to avoid any increase. The change in RES curtailment was also assessed, as the region is projected to have high growth in weather dependent PV and wind capacities in the various scenarios. There is a slight increase in the RES curtailment value in Greece, but it remains very low, due to the increased interconnection level with Bulgaria, which helps to avoid higher curtailment levels.

The modelling also demonstrates the importance of high **interconnectivity**. While price differences among the scenarios are around 7-8 EUR/MWh between Greece and Bulgaria at the beginning of the modelled period, and still around 5 EUR/MWh in 2022, after the new interconnector comes online in 2023 this price difference disappears entirely for the next 3 years. The two markets do not diverge by more than 1 EUR/MWh later on in any of the modelled years.

The EEMM model calculates the **welfare impacts of the phase-out scenarios** resulting from a change in the electricity wholesale price. Three welfare impacts were assessed:

- Consumer surplus shows the changes in end user electricity bills due to changing wholesale electricity prices. As prices are generally higher in the early phase-out scenarios, this represents losses (higher bills) for electricity consumers.
- Producer surplus shows the net income of electricity generators resulting from the changes in fuel input and electricity prices. The phase-out scenarios result in a net gain for producers, as wholesale electricity prices generally increase in these scenarios
- Rent change shows the changing income of TSOs received from electricity traders for utilising cross-border capacities. Due to the varying trade patterns and utilisation rates of the interconnectors, this rent is higher in the early phase-out scenarios. This process represents a sizeable income for TSOs, providing TSOs with funding to improve transfer capacities or to reduce consumer tariffs.

The welfare impact results are contained in Tables 34-37 in Annex 2. The tables show the difference in welfare compared to the Reference scenario. The following conclusions can be drawn from the welfare assessment:

- Final consumers face a sizeable electricity bill increase – ranging between EUR 0 to EUR 565 million/year in Greece, between EUR 0 to EUR 510 million/year for Bulgaria and up to EUR 406 million/year in Romania over the next decade. This increase is higher when a more stringent phase-out scenario is implemented.
- However, the overall welfare change is more limited due to the benefits for producers and TSOs.
- The increase in revenues to producers allows government to reduce financial support to power plants and use these revenues to implement renewable energy investment and end use energy efficiency measures, and to protect vulnerable consumers. The information on current state subsidy levels are not fully available, but are estimated at EUR 450 million in Bulgaria, while in Greece it is said to cover losses in power plants, estimated at around EUR 900 million. (Prodromou & Mantzaris, 2018) The subsidy level for lignite power plants in Romania is expected to be around EUR 200 million per year over the next 10 years according to current proposals.

2.3 Funding a just transition

The closure of power plants is inevitable given the high and increasing carbon price and the current losses generated by several power plants in the region. The costs discussed in this section are therefore not closely linked to the modelled early closures of power plants but become applicable whenever the closure happens. The aim of the assessment is to support countries in the region in preparations for funding a just transition using funding made available through the Just Transition Mechanism as well as other available funding, such as ERDF, ESF and the Cohesion Fund.

The results of the analysis of regional economic impacts of power plant closures (using the methodology contained in Annex 1) in the three countries shows that more than 84 thousand jobs will be lost as a result of plant closures.

Table 3 Number of jobs lost (workers <55 years)

	Direct, power plant	Direct, mine	Indirect	Total
Bulgaria	2355	11763	29120	43238
Greece	1975	3626	7010	12611
Romania	2761	6315	19332	28408
Total	7091	21704	55462	84257

Funding is required to compensate for these negative impacts of closures consisting of the following elements:

- Investment needed to offset direct job losses either through reskilling and business support or early retirement;
- Investment needed to offset indirect jobs losses;
- Investment required to boost regional development to offset GVA losses.

In addition, support may be required to protect vulnerable consumers from temporary price hikes to ensure a just transition, if an early phase-out is implemented. This has been discussed in section 2.2.

Total funding needs have been estimated for the affected NUTS regions and are summarised in Table 4. Of the necessary funding it is expected that a significant portion of investment for regional development and some of the payments for offsetting job losses can be delivered through loans and financial instruments rather than through grants. It can be noted that the expected cost per worker is significantly higher in Greece than in Bulgaria or Romania. The reason behind this, in addition to a difference in current salaries and living expenses, is the much higher initial unemployment level, making job creation and job placement much more difficult in Greece.

Table 4 Total funding needs in the three countries for a just transition, thousand EUR

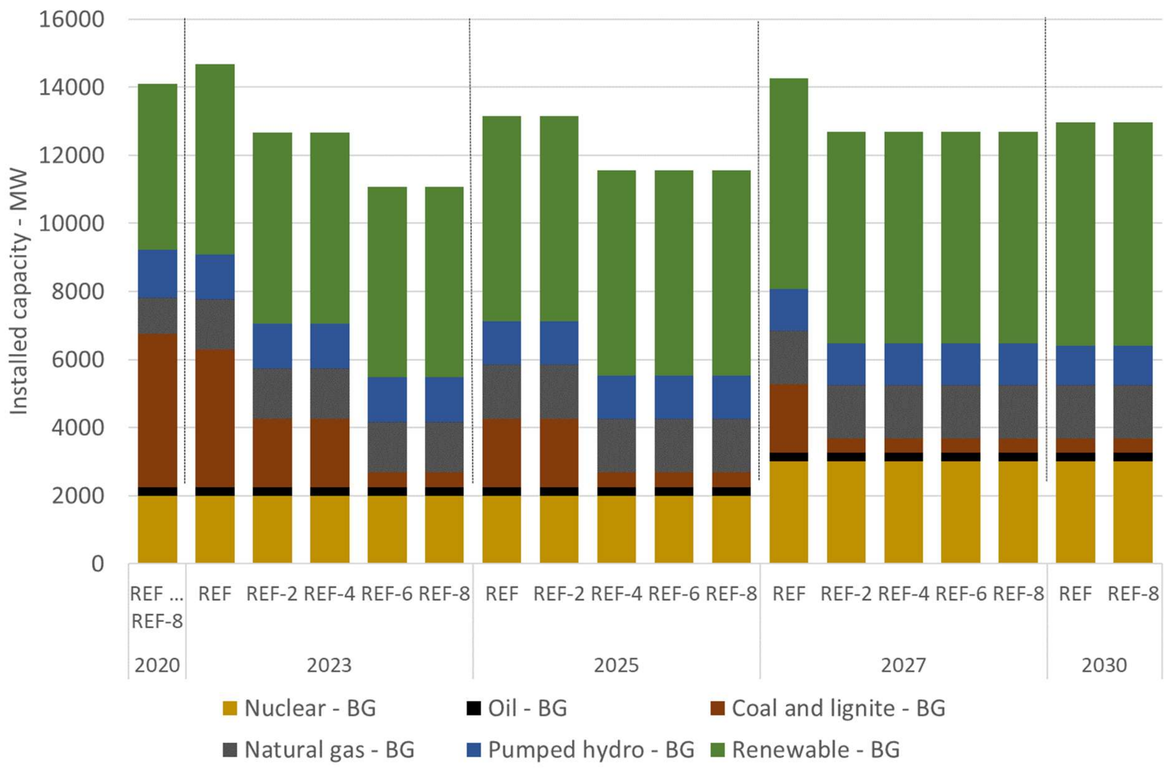
Country	Bulgaria	Greece	Romania
Payment to offset direct job losses	220,322	226,885	112,086
Payment to offset indirect job losses	140,560	257,516	108,743
Investment in regional economic development	531,551	1,619,125	479,701
Total funding need for regional development	892,433	2,103,526	700,530

3 Bulgaria

3.1 Modelling results

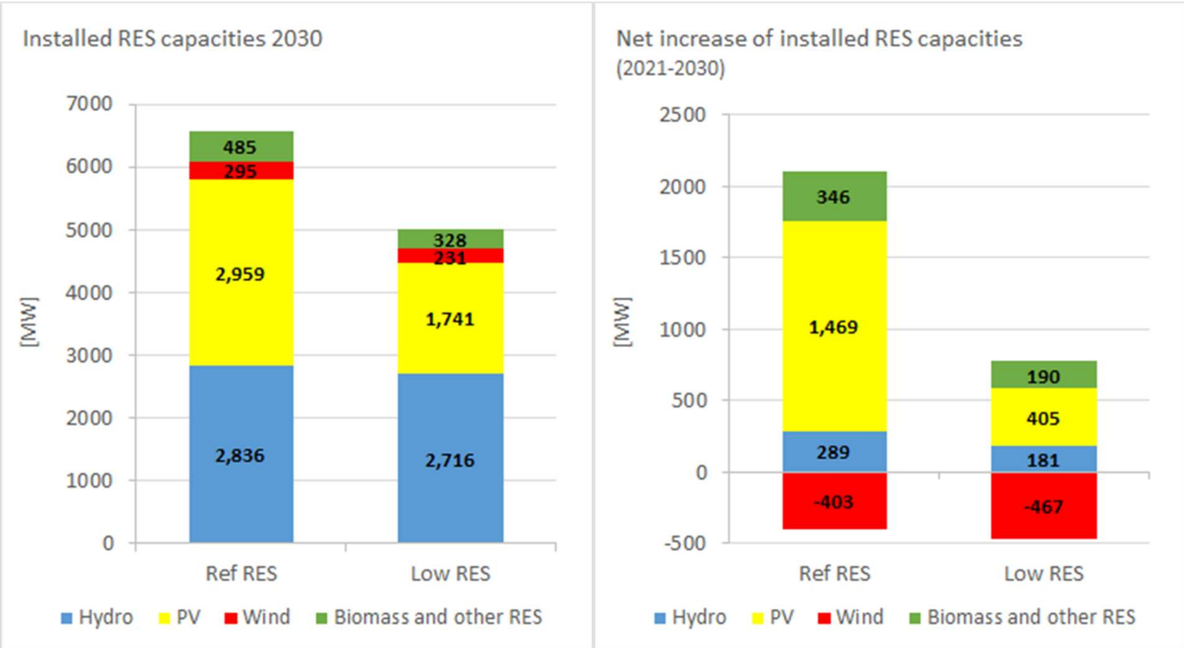
Change in **installed capacity** in the different scenarios is mostly exogenous. The model can install new fossil capacities, but this opportunity is not exploited, as new exogenously included natural gas and nuclear capacities and one new coal plant are sufficient to replace outgoing capacities to satisfy a growing demand for electricity. The new natural gas capacities come from the retrofitted Varna plant, while the continuous phase-out of coal and lignite capacities ends by 2030, with a remaining capacity of only 422 MW in all analysed scenarios, compared with 3750 MW in 2018. Renewable capacities increase from a total of 4.9 GW in 2020 to 6.6 GW by 2030. The base year for the modelling is 2018, therefore the results shown for 2020 are modelled results.

Figure 10: Installed capacity by type in 2023, 2025 and 2027 in Bulgaria



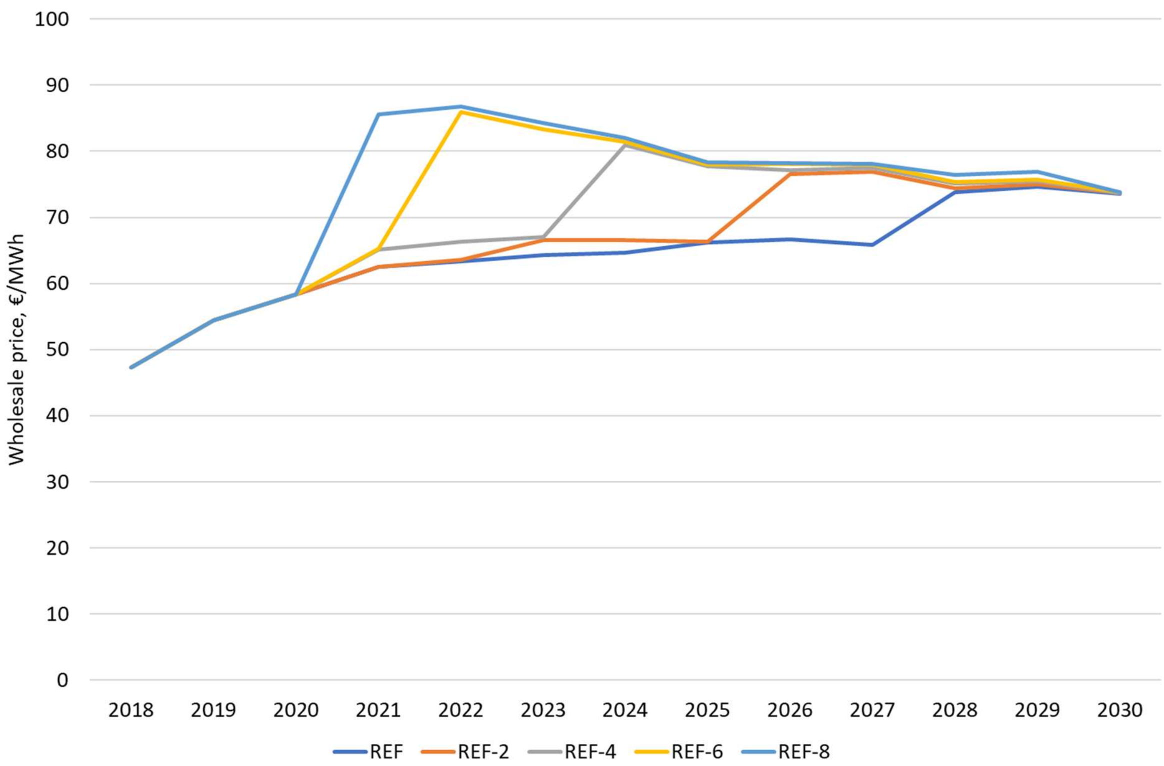
Sensitivity analysis was performed for the targeted 2030 RES share with a Low RES scenario. The reference (Ref RES) scenario for the RES uptake results in a total of around 6.6 GW RES capacity in 2030, with hydro and PV dominating. This means around 1.7 GW net increase in the renewable capacity in the next decade. The Low RES sensitivity scenario (with already somewhat lower RES capacities in 2020) results in total renewable capacity of around 5 GW in 2030 with a total net increase of 0.3 GW.A net decrease in wind capacity is visible in both scenarios: close to 0.4 and 0.5 GW in the Ref RES and Low RES scenarios respectively.

Figure 11 Total installed RES capacity (left) and RES capacity increase (right) in the reference (Ref RES) scenario and Low RES sensitivity analysis in 2030 in Bulgaria



Phasing out lignite plants has a significant **wholesale price impact** in Bulgaria. It is clearly visible that each step that brings forward the closing of lignite plants by two years results in a jump in the wholesale electricity price – the sooner the phase-out, the higher the price increase. Closing down plants 8 years earlier than planned would increase wholesale electricity prices by more than 20 EUR/MWh in 2021, this effect is a few euros less and happens somewhat later if the phase-out happens 6 years earlier than planned; the price increase is 15 and 10 EUR/MWh in the REF-4 and REF-2 scenarios, respectively. From 2028 onwards almost all scenarios arrive to the same wholesale price levels as by then there are only small differences in installed lignite capacity between scenarios. Most lignite plants close down by 2030 irrespective of scenario.

Figure 12 Wholesale electricity prices in REF and early phase-out scenarios in Bulgaria

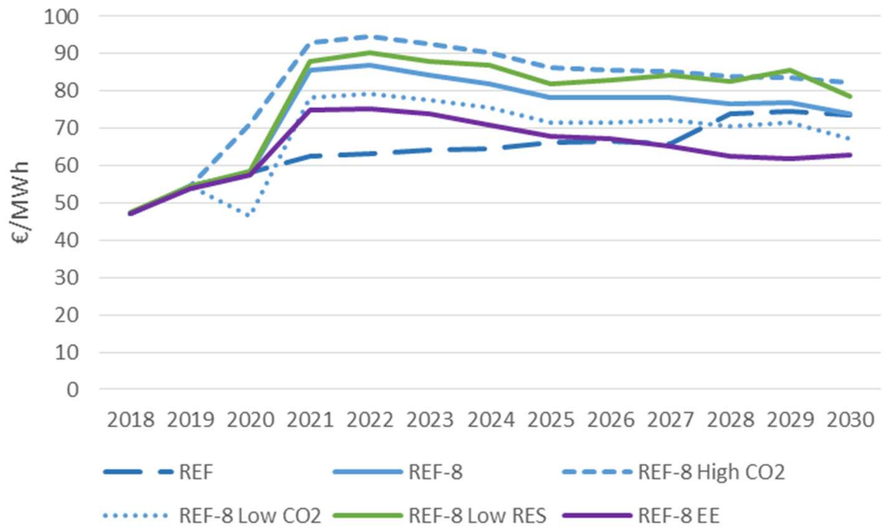


The sensitivity analysis indicates that there are ways to reduce wholesale prices, to partially offset some of the price increase resulting from early lignite plant closure.

The most important instruments is reducing electricity demand. Since the reference scenario demand projections were made before the covid-19 epidemic, it is likely that a reduced demand scenario more accurately reflects expected demand growth during the next few years. A sensitivity analysis was prepared where instead of assuming demand in line with national documents, it was assumed that demand would be consistent with the 32% RES 32.5% EE targets for 2030 modelled using PRIMES. The price impact can be reduced significantly if demand growth is kept in check in the lower demand scenario. The temporary hike in wholesale prices can be reduced to 12 EUR/MWh, and over the medium term, after about 4-5 years, the price impact of an early phase-out disappears if demand growth is reduced. By 2030 the scenario with early phase-out and lower demand combined results in a lower wholesale electricity price by 11 EUR/MWh than the reference scenario. This can be seen in Figure 13.

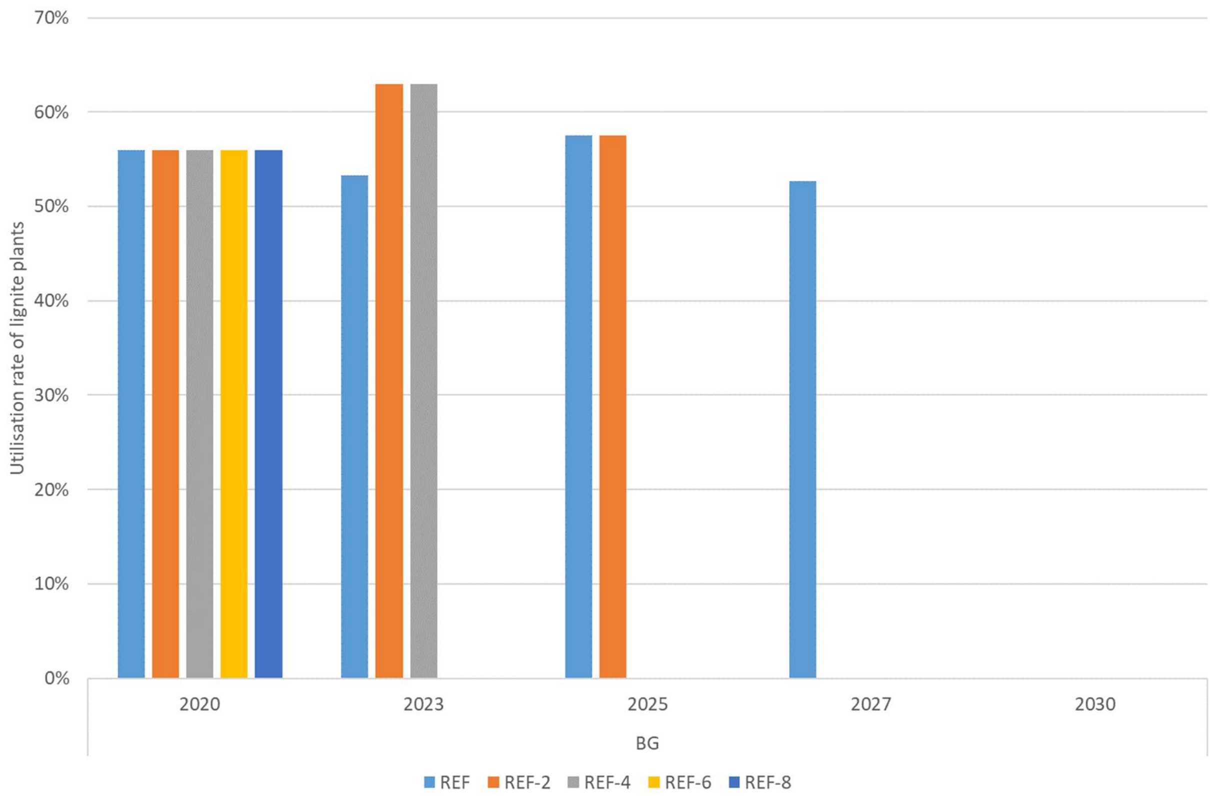
The Low RES scenario shows that RES share is negatively correlated with the wholesale price increase; therefore an increase in RES share can reduce prices. Lower demand, representing yearly growth rate of only 0.4% compared with 1.1% in the reference scenario, also lowers wholesale prices significantly, demonstrating the importance of lowering demand in reducing prices.

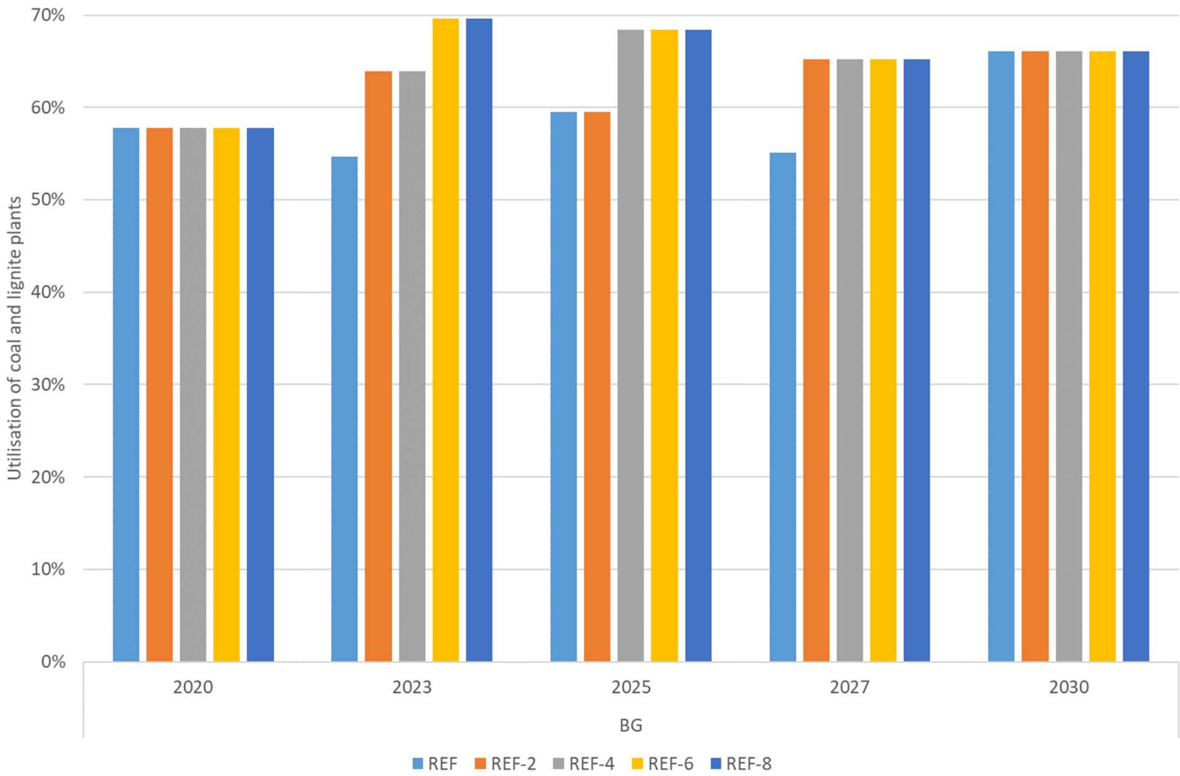
Figure 13: Price impact of different CO2 price levels, lower RES penetration and lower demand in the REF-8 scenario in Bulgaria



Lignite plants in Bulgaria reach the highest utilisation levels amongst the three countries analysed. Plants function at close to 60% utilisation rates, increasing somewhat with the closing of older units. The higher utilisation rates compared with Greece and Romania are the result of lower lignite prices, resulting in lower marginal costs and higher competitiveness of these plants in the region. The newest coal-fired unit TPP Rousse D, to come online in 2020, reaches a utilisation rate higher than 80% in 2025. However, by 2030 only 5-6% of total production comes from coal and lignite in all analysed scenarios.

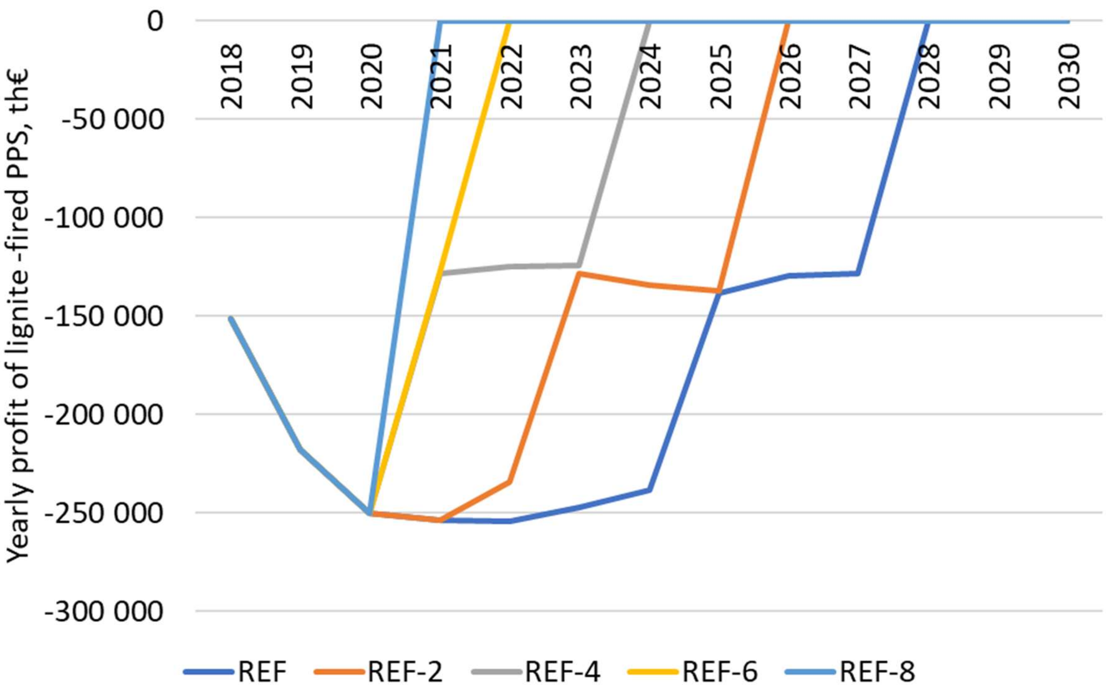
Figure 14 Utilisation rates of lignite (top figure) and lignite and coal (bottom figure) power plants in Bulgaria





Profits of lignite plants (defined as: revenue from electricity production – variable costs - yearly fixed costs) are negative in all the analysed scenarios due to their high yearly fixed costs – without accounting for the many forms of support provided for these plants currently by the government. The above high utilisation rates can only be sustained over a longer period if support remains in the system. From a strictly economic point of view these plants will most likely close down without any regulatory intervention if government support ends.

Figure 15: Aggregated yearly profit of the lignite-fired PPs in Bulgaria

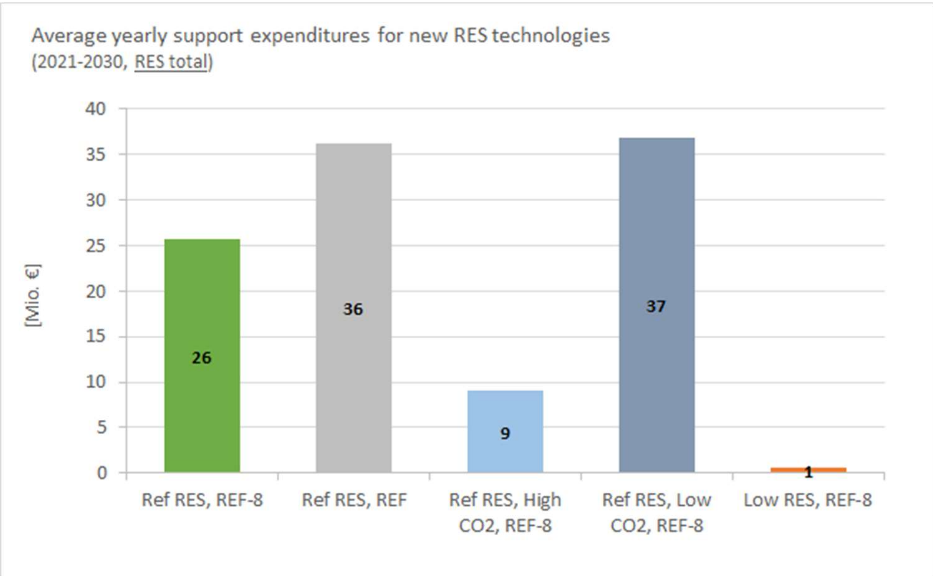


Current government support, estimated at EUR 450 million per year, to aged lignite plants helps to retain these units in the system and keep wholesale prices low. However, these plants are not economical to operate, and thus an early phase-out would not require high compensation for these units to close, especially considering that losses in remaining units can be reduced by these closures. Early closure would also free up government funds which could be targeted at vulnerable consumers most affected by the price increase. Consumers would face around EUR 500 million **welfare** loss in the most severe phase-out scenarios (REF-8, REF-6) for few years (2021-2023), which loss goes down significantly afterwards (see tables 34-37 in Annex 2). This maximum loss is of similar magnitude to the current estimated government support to the aged lignite plants, which is around EUR 450 million. This funding could be used to compensate vulnerable consumers rather than supporting lignite power plants, or for investing in low-carbon infrastructure, demand-side measures and financial stimulus/support measures for small scale RES, etc. At the same time remaining producers and network operators would face significant welfare gains due to increased profitability and more intensive use of network elements in the next decade. Producer welfare gains would reach EUR 300 million, while rent change for the TSO would reach EUR 34.1 million. This means that if the remaining producers and closed lignite plants are in the same ownership, considerable compensation takes place through the producer welfare gains of remaining plants; this has to be considered when deciding whether power plants need to be compensated for early closure. If ownership is separated for the closing and remaining plants the situation becomes more complex. TSO rents could be used to improve the interconnectivity between countries, or lower network tariffs for end users to reduce the negative impacts of the price increase on consumers.

As mentioned above, results show that the reference scenario enables lower electricity prices than a Low RES scenario, indicating the inverse relationship between RES deployment and wholesale electricity prices. The RES uptake may therefore serve as a policy tool to control the increase in electricity prices, as RES helps shield consumers from two important drivers of electricity price growth (the carbon price and natural gas prices).

An average yearly **investment in RES capacity** of about EUR 241 million is needed in the next decade in the reference (Ref RES) scenario. Support needs for RES depend on the carbon price as well as on the timing of the lignite phase-out: an early phase-out policy (Ref RES, REF-8) would result in EUR 26 million - and only EUR 9 million combined with a high carbon price trajectory (Ref RES, High CO_2, REF-8) - compared to the EUR 36 million average yearly support expenditures in the case of a less proactive coal phase-out (Ref RES, REF). These figures are very low compared with support received by lignite plants currently. Both early phase-out of lignite and high CO_2 prices reduce the required support through the increasing wholesale prices which, in turn, allow RES investors to recover the cost of their investment at lower public support levels. However, considering a given RES penetration level consumers must either face a combination of lower electricity prices and a higher support element, or a higher electricity price and a somewhat lower support element. In the reference (REF) scenario on the coal phase-out the total support is slightly higher than 2% of the wholesale electricity prices by 2030 if paid by all consumers equally, and it is a bit lower than 2% in the REF-8 scenario (with an earlier phase-out proclaimed).

Figure 16 Average yearly support expenditures for new RES capacities in Bulgaria in 2021-2030



The **net import position** of Bulgaria is likely to change significantly. Bulgaria becomes a net importer of electricity from currently being one of the biggest exporters in the EU. This happens regardless of the phase-out, but the speed of the change can be influenced by the timing of decommissioning. From 2020 to 2030 flow directions change on all interconnectors except Turkey, where import is more or less stable in all years and scenarios. The commissioning of new cross-border capacities with Greece triggers changes in the system: the 4 TWh/year net export in 2020 shifts to a 6 TWh net import position with Greece by 2030 in both the reference and the REF-8 cases. In 2030 there are no more lignite capacities online in Bulgaria under any of the scenarios. These units operate with high utilisation rates until their closure dates, when local production is mainly replaced by imports. This is also visible when we compare the REF-8 and the REF case in 2025: the decommissioning of all lignite plants by this date in the REF-8 scenario results in a much higher net import position than in the reference scenario already in 2025 with most neighbours except Turkey. However, it cannot be generally concluded that lignite plants are required to maintain a net exporter position – in the case of Greece the early phase-out and high RES capacity jointly enable an improvement in the net importer position of the country, allowing it to reduce imports, as a high RES share confers competitive advantages in a regional market beset by high carbon prices and high natural gas prices.

Table 5 Net electricity import for Bulgaria in 2020, 2025 and 2030 under the REF and REF-8 scenarios

Net import from, GWh/y	REF			REF-8		
	2020	2025	2030	2020	2025	2030
GR	-4 362	-175	6 053	-4 362	2 978	6 090
MK	-1 662	353	204	-1 662	735	238
RO	-2 213	763	1 214	-2 213	1 557	1 165
RS	-1 939	511	473	-1 939	989	436
TR	2 567	2 487	2 287	2 567	2 507	2 287
Total net import (GWh/y)	-7 609	3 938	10 231	-7 609	8 766	10 216

Modelled capacity and interconnection levels can help maintain **system adequacy** in the next decade. The adequacy modelling carried out with the EPMM unit commitment model shows that reserve capacity needs could be maintained, sufficient level of spinning and non-spinning reserves stay in the system. The 5% minimum reserve levels are available in both downward and upward regulation in Bulgaria. The energy not supplied (ENS) values showed no increase in the assessed two years (2023 and 2029) in the case of phase-out, as interconnection levels and new RES and gas fired capacities are sufficient to avoid any growth in ENS. RES curtailment showed no increase in Bulgaria.

3.2 Just transition

In Bulgaria in the four affected NUTS3 regions (Burgas, Stara Zagora, Pernik and Kyustendil) the number of employees is around 25,500, with around 75% of these working in the lignite mining sector, and the remaining 25% in power plants. Around 20% of workers are above 55 years of age. There are significant differences among the regions regarding the number of employees.

Table 6 Expected job losses from a coal phase-out and government payments to compensate for lost jobs, Bulgaria

Industrial sector	Number of jobs lost		Financing needs (thousand EUR)
	< 55 years	55 years or older	
power plant	1 943	412	220 322
mine	9 705	2 058	
Total direct jobs	11 648	2 470	
Indirect jobs	29 120		140 560

Stara Zagora is the region most affected by the transition, with the highest number of workers in the coal sector. At the same time, Stara Zagora is also the most dynamically growing region, therefore it has good potential to absorb coal sector workers made redundant by the phase-out.

Stara Zagora holds the potential to replace lost revenue and employment opportunities through its other industrial sectors, such as the manufacturing of machinery, industrial equipment, and metal products. The industrial restructuring of the region will benefit from the engineering heritage of the region, the different professional skills of the workers in various industrial branches, which could also increase the attractiveness of the region for future investors and create favourable environment for various startups. There is a concentration of companies that produce machinery and equipment for the food industry and agricultural sectors, including hydraulic parts for agricultural equipment, or large-scale food processing machine manufacturing, and smaller companies that are specialized in food related machinery manufacturing. These enterprises have been steadily increasing their efficiency, production quality, and foreign investments, and a significant part of their produce is exported, which implies they are competitive and have access to large markets. Stara Zagora's economy also contains large companies that specialize in the chemical industry, especially for the production of fertilizer, manufacturing of plastics and rubber products, and extraction of essential oils to be used in cosmetics. Additionally, the province is home to companies that are specialized in iron casting and hot forging processes. While the equipment they produce are currently used by the mining and energy industries, they are also used in agriculture, hydraulic parts, lifting and construction machines, railway and auto transport, and machinery. These companies have existed for over a century, use advanced manufacturing equipment, continually invest in employee training, and export internationally, especially to the EU. The training could also focus on new job opportunities such as in retail trade, reprocessing secondary materials into new ones, the automotive industry and its supply chain. Stara Zagora is also home to metal and wood processing companies and companies that manufacture a variety of professional instruments and tools.

Regarding Pernik, the concentration of mines implies that the province will be noticeably impacted by a transition. While Pernik has a rich history of energy related economics, the province is also home to a variety of industries that could provide alternative opportunities for employment and revenue, such as companies specialized in steel (plates, beams and construction steel) production, metal structures, industrial fans, industrial filters and metallurgy equipment. The Municipality of Radomir also hosts companies specialized in mechanical engineering and manufacturing of crushing and grinding machines, as well as machines and equipment for metallurgy, foundries, heavy construction, and load handling. The region also hosts companies specialized in producing electrical boards and metal and mechanical commodities. Companies that are currently servicing the lignite industry, have the opportunity to switch to manufacturing machines for the cement industry, shipbuilding, power engineering, and metallurgy. The Pernik province is also home to chemical and wood processing industries, as well as to producers of cement, waterproofing material, and a variety of other chemicals used in construction sectors. In the Pernik province there is also pharmaceutical and cosmetics manufacturing, wood processing and furniture production.

Finally, the, Kyustendil province is also estimated to be impacted by the transition away from lignite because of its mining enterprises and the Bobov dol TPP. However, there are also industrial enterprises that can compensate for the resulting loss of revenue and even absorb the lignite sector’s workforce. One of the obvious sectors that can absorb lignite sector’s workforce is its zinc and lead concentrate production facilities. The province is home to several companies in the construction field that specialize in industrial, commercial, residential, and temporary buildings construction, as well as in the manufacturing of construction materials, such as concrete products, metal structures, and asphalt. With the new EU renovation wave initiative and the review of the construction product regulation, there will be a strong emphasis on energy savings in the buildings sector and zero-carbon building stock, which could lead to the creation of new green jobs (in particular architects, electricians, plumbers, carpenters, roofers, etc.) and innovation of the service offers. In addition, the province is home to chemical and pharmaceutical plants.

It is estimated that a total investment of around EUR 531 million is required to offset the GVA losses in coal regions resulting from the phase-out. When including the figure required for compensating for employment losses, the total funding required is EUR 891 million. Some of this, if made in productive investment, may come in the form of loans and other financial instruments. This figure is small compared with the annual support of around EUR 450 million currently needed to keep lignite plants operational.

3.3 Policy conclusions

Green energy transition in Bulgaria poses many complicated political, administrative, regulatory and business governance dilemmas. The use of the large lignite reserves in the country for electricity generation has been seen as the foremost guarantee of the security of energy supply and the independence of the national electricity system. It is also the source of income for several regions, various business interests in the country and the employment of over 14,000 workers directly and close to 20,000 indirectly.

In recent years the EU's higher requirements for air pollution control measures aiming to reduce the serious negative environmental and health risks associated with the operation of lignite power plants have led to a gradual reduction of subsidies for the industry. In the last two years the sector also faced steeply rising price of CO_2 emissions. These developments combined with the delayed planning of the energy transition by the Bulgarian government and lack of alternative sources of energy generation have meant that the continued reliance on lignite power plants has begun to form sizable financial losses for the state-owned electricity sector. Further cost increases are expected as a result of the increasing EU environmental standards for the emissions of NO_X, SO_X and mercury gases emitted by large combustion facilities. To fulfil the criteria of the EU Industrial Emission Directive (IED), lignite plants would have to undergo a serious modernization, which could cost up to EUR 1 billion[6]. The Bulgarian government has reacted to this situation by seeking a derogation for the IED, and proposing a new capacity payment scheme aiming to extend the life of lignite plants beyond 2025.

However, the alternative option of closing down these lignite plants and ensuring that alternative generation capacity is available to satisfy demand has not been on the agenda at least not until the final version of the National Energy and Climate Plan (NECP) published in February, 2020. Although in its main conclusions, the energy ministry maintains that most lignite plants would be operating at least until 2030 with a 2050 horizon. The estimates in the final draft of the document reveal that coal-based electricity generation would fall from around 45% today to 30% in 2030 after the closing of around 1.8 GW of capacity. An almost full coal phase-out is not expected before 2040 according to the NECP.

The results from the modelling assessment in Bulgaria reveal that an earlier closing of the lignite-fired power plants would increase the overall **profitability of the thermal power plants** remaining in the system. This is an opportunity to decrease existing subsidies for lignite power production that can be estimated at around EUR 450 million per annum, based on information related to the size of support from power purchase agreements, preferential FiTs, cold reserve payments and state support for the purchase of EUAs. This support comes in various forms, including long-term, preferential PPAs, support for thermal power plants that function artificially as district heating plants in order to receive preferential FiTs for CHP-based electricity generation, and payments for cold reserve capacity. The latter support is rarely activated and is

[6] Joint Research Centre. (2017). Best Available Techniques (BAT) Reference Document for Large Combustion Plants: Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control). Science for Policy Report, December, 2017, accessed at http://eippcb.jrc.ec.europa.eu/reference/BREF/LCP/JRC_107769_LCPBref_2017.pdf

currently monopolized by lignite-based power plants and often the only mechanism for their financial survival.

The analysis provides an opportunity for decision makers to re-evaluate various forms of support for lignite power plants in light of the modelling results showing that lignite plants could be phased out in Bulgaria without endangering security of supply.

The systematic closing of the least competitive lignite plants would increase the utilization rates of the remaining generation facilities, including some renovated and more effective lignite plants. The state-owned Maritsa Istok 2 currently operates at only 50-60% capacity and at market prices it does not break even. Closing of this plant would allow for higher utilization rates at around 80% in most scenarios for the remaining facilities. Additionally, the closing of the state-owned plant may be preferred as early closing of the two privately owned plants AES Galabovo and Contour Global Maritsa Istok 3 would likely lead to court claims and compensation payments for cancelling long-term PPAs which would increase the overall cost of the transition.

The early closing of lignite plants leads inevitably to a temporary spike in **wholesale electricity prices**, and would lead to an increasing consumer bill in the short run (i.e. 2 to 3 years after the first plants are closed in 2021). The price effect calls for public policy measures to reduce the impact on the most vulnerable social groups, as Bulgaria is planning the full removal of regulated power tariffs around the time of the sharpest price spikes. These can include the expansion of direct financial transfers, social tariffs for the most vulnerable consumers, and the introduction of virtual net metering to incentivize community energy.

Other policy tools are also available to protect consumers from a sudden increase in end user prices. The Bulgarian government could focus on developing demand-side response mechanisms to shave the peaks during the extreme demand periods of winter including the introduction of tertiary-sector tenders (industrial sector energy savings), a much bigger focus on energy efficiency (especially in manufacturing industries and transport sector), significant reduction of energy losses in transmission and distribution network, and the reservation of regulated tariffs only for the most vulnerable social groups.

Bulgaria will probably become a net **importer** of electricity after 2025 (for about 10% of gross consumption in the reference scenario and up to 25% in the more ambitious earlier closing of lignite plants) but the power system would not face significant **supply security** issues when the lignite-fired power generation capacity is reduced by more than 50% according to the modelling results. This leads to questioning the rational of capacity payments, and whether this constitutes state aid that may exacerbate market distortion and leads to lock in unsustainable generation capacity.

The governments in the region should accelerate the completion of key power **interconnections** including the Bulgaria-Greece high-voltage power line and the 1,200 MW Bulgaria-Romania link that is currently not planned to be completed by the start of the phase-out of lignite plants. The power interconnections would reduce the peak power prices and help the SEE-CEE power market integration by reducing existing bottlenecks.

Moreover, the results of the modelling shows that the price increase is much lower in Romania than in Bulgaria and Greece, demonstrating the importance of **market interconnectivity**. It is crucial for the Bulgarian TSO to work in cooperation with neighbouring operators to increase the allocation of net transfer capacity (NTC) on the border with Romania and Greece as currently only a fraction of the technical cross-border capacity is in use, which effectively blocks regional power trading.

In a scenario with an earlier closure of the lignite power plants, there will be the strong need for the Bulgarian power system to utilize more efficiently the country's run-of-the-river HPP installed capacity, which currently is utilized at less than 20% of its capacity (overall utilization rate of pumped storage facilities depends on the level of water reservoirs but has hovered around 60%). This would require removing the current regulatory bottlenecks for water use on run-of-the-river HPPs, an entirely new program for the modernization of HPPs, and achieving a more market driven production profile of the state-owned HPP producer, NEK's, especially during peak demand periods.

The lignite phase-out process would enhance the transitional **role played by natural gas** in the electricity system in the mid-term. Natural gas will become more competitive due to the rising wholesale prices and increasing CO_2 costs, and its role could be expanded either as a replacement fuel in existing generation facilities or in new gas-fired power plants. Natural gas would play a strategic role to maintain security of supply amid rising RES-based power generation, especially in the high RES scenario. However, it should also be viewed as a potential drag to the overall decarbonisation policy as it could lead to a new lock-in for fossil fuel dependence.

However, the projected increase in the price of natural gas is also a major factor driving the increase in electricity prices over time. For this reason, governments should have a strong focus on increasing the share of renewables, as wind and photovoltaic generation costs are not influenced by the price of natural gas or carbon allowances, and presents an increasingly competitive way of electricity generation.

The increasing share of natural gas in the power system would be facilitated by the likely completion of the IGB interconnector by the end of 2020 which would bring 1.5 bcm/yr of alternative Azeri and LNG gas to Bulgaria leading to a more competitive pricing. The ongoing natural gas market liberalization is expected to be completed in the next five years which would help to unlock the gas potential in the power sector. The better regional gas market integration would provide for more gas liquidity and lower prices incentivizing a coal-to-gas switching.

A key prerequisite for the effective integration of natural gas in the Bulgarian power system would be the removal of technical, regulatory and governance bottlenecks for cross-border transmission capacity bookings and the use of existing LNG regasification terminals on the Aegean coast in Greece and the Mediterranean in Turkey. Bulgaria's participation in the development of a new regasification terminal at the port of Alexandroupolis would also provide gas suppliers with an additional foothold on the global gas market. Taking advantage of current gas price differentials between long-term oil-indexed contracts and spot-based LNG would reduce the average gas prices in the country boosting the commercial viability of new gas-fired plants.

The current modelling exercise was only carried out until 2030, and therefore does not provide information on the long term economic viability of gas. Previous modelling using the EEMM and Green-X models where scenarios were run until 2050 showed that the expansion in gas use is temporary under high renewables scenarios and that natural gas assets built during the 2020s might become stranded in the long run.

The construction of the Belene **nuclear power** plant project increases in economic attractiveness as the wholesale electricity price increases. However, the project could create serious risks for crowding-out of renewable energy investments over the medium to long term.

The model results demonstrate that higher **renewable energy** integration in the system leads to lower wholesale prices. However, achieving high renewable shares is only possible if governments both reduce administrative and regulatory burdens for new RES investment and redirect infrastructure policy towards innovative decentralized solutions (such as flexible generation, demand-size response, storage technologies and more efficient grid management. They can alsoreallocate the state revenues from selling ETS certificates on the European market to support new renewable projects. As overall market prices increase significantly in the more ambitious phase-out scenarios, the cost of the RES support mechanisms, which could be in the form of tenders, would be minimal.

The final draft of the Bulgarian NECP has somewhat adopted a more ambitious RES integration scenario for the next ten years. RES-based power generation capacity is expected to increase from the current 4,3 GW to close to 7 GW in 2030 largely based on solar PV capacity additions up to 2,2 GW. As a result, the NECP projections for the share of RES in the electricity sector become more in line with the modelled High-RES scenario, whereas the Bulgarian government expects hydro, solar, wind and biomass to contribute around 30,33% of the final electricity consumption in 2030.

The modelling results show that the consumer cost for supporting new RES installations in the forthcoming decade ranges from zero to around 0.2 EUR/MWh on average in the 2021-2030 period in scenarios with only a small increase in RES capacity (Low RES scenarios), and between 0.2 EUR/MWh to 1.7 EUR/MWh in the case of a stronger RES uptake . In comparison, the existing social responsibility tax, used to cover state subsidies for renewables and coal-fired IPPs with PPAs, costs power consumers 10 EUR/MWh. Stronger penetration of RES in the power system reduces the overall profits of remaining lignite-fired power plants (NPVs fall by around EUR 200 million) increasing the incentive for earlier phase-out.

In total, Bulgaria is the country with highest net welfare impacts of an early phase-out, with around EUR 500 million per year lost consumer surplus loss annually. The impacts of an early phase-out on consumers are high in comparison to e.g. Romania. Addressing the welfare impact of the price increase needs to be part of the government's just transition agenda if an early phase-out is implemented.

There is a need for policy makers to implement a **just transition agenda**. The cost assessment of the coal phase-out in the most dependent regions showed that more than 25,000 power plant and mine workers would be directly affected by the transition. Another 19,300 jobs in related industries would also be indirectly impacted by the closing of the plants and the associated lignite mines. This would require the development of targeted programs for re-training and job replacing programs for all workers below 55 years. The cost of such government initiatives would be around EUR 364 million, which also includes the early retirement costs.

However, the just transition process goes beyond compensations for workers and involves the creation of an institutionalized support structure for the worst affected economic sectors and regions. This means the rechannelling of funding streams towards the most vulnerable areas including the mining, manufacturing, electricity, construction and transportation sectors where the estimated lost value-added would be EUR 425 million with the Stara Zagora region impacted the worst. There will be an urgent need for additional investment in a number of absorption sectors that have shown the greatest potential for economic growth. These include high value-added manufacturing, construction, agriculture and commerce. There is a need to create incentives for new green startups in the automotive industry and its supply chain, reprocessing of secondary materials, training and development sector, research, service sector, etc.

Important for the successful implementation of a just transition is its timely start and good governance at national and local level. Strategically considered, coherent and concrete measures for the gradual transformation of coal regions are needed. However, to date, Bulgaria is not participating in the EU's Platform for Coal Regions in Transition pilot project. The idea of the platform is to invest in projects for alternative energy sources, energy efficiency, the creation of industrial clusters or data centres in coal-dependent regions.

Achieving a just transition in the regions dependent on the coal industry will be a costly process that will require the mobilization of significant national and European financial resources. A comprehensive stakeholder engagement and consultation process should gather representatives of different businesses and government institutions to improve the targeting of the economic support feed into the regional development programme and implementation of smart specialisation strategies in order to boost competitiveness and job creation.

With the New Green Deal and the next Multiannual Financial Framework (MFF 2021-2027), Bulgaria should grasp the momentum of the next largest investment cycle to plan strategically and facilitate the industrial restructuring in the coal regions, as well as identify the right incentives and financial mechanisms to support the adjustment of coal workers in the regions undergoing transition. Since previous lignite mines are particularly attractive for large-scale solar power generation and could benefit from the industrial heritage, the concentration of engineering skills and land availability, innovation and industrial opportunities should be grasped and supported through the right policy framework and new public and private investments.

The European Commission aims to allocate at least 25% of the funds under the next European Multiannual Financial Framework for the purpose of achieving a carbon-neutral economy[7]. A number of EU financial instruments can be used by Bulgaria to achieve a fair energy transition in the country, including the Just Transition Mechanism, the Cohesion Fund, the European Social Fund, the European Regional Development Fund, the Invest EU instrument, Horizon Europe, the European Globalization Adjustment Fund, the Innovation Fund and the Modernization Fund.

These specific financial instruments may include other related horizontal programs, such as the Connecting Europe Facility (CEF), which can finance cross-border energy projects such as increasing the transmission capacity and flexibility of the system so that it can be traded more effectively RES electricity in the region. The required investments in the Bulgarian electricity transmission network are estimated at about EUR 92 million[8]. In addition, the government will be able to use the proceeds from the sale of carbon allowances to invest in green energy projects or to modernize coal power, although 40% of the allowances will still be earmarked for the TPPs themselves[9].

[7] Commission Staff Working Document (SWD/2018/171). Spending review Accompanying the document. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions. A Modern Budget for a Union that Protects, Empowers and Defends The Multiannual Financial Framework for 2021-2027

[8] CSD Policy Brief № 70: Пътна карта за развитието на българския електроенергиен сектор в рамките на Европейския съюз до 2050 г.: основни жалони. София: Център за изследване на демокрацията, октомври 2017.

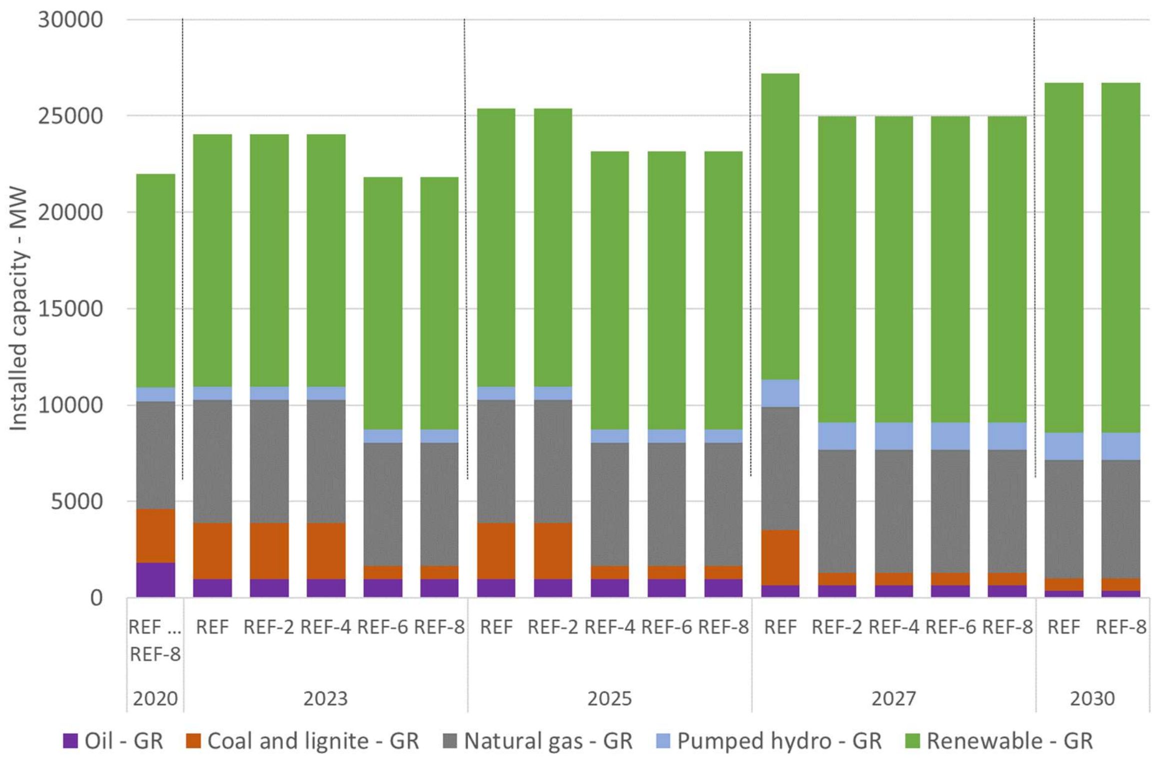
[9] However, the savings will need to be channeled beyond 2021 only for carbon reduction and environmental projects. The modernization of coal facilities could potentially extend their lives by at least 2030.

4. Greece

4.1 Modelling results

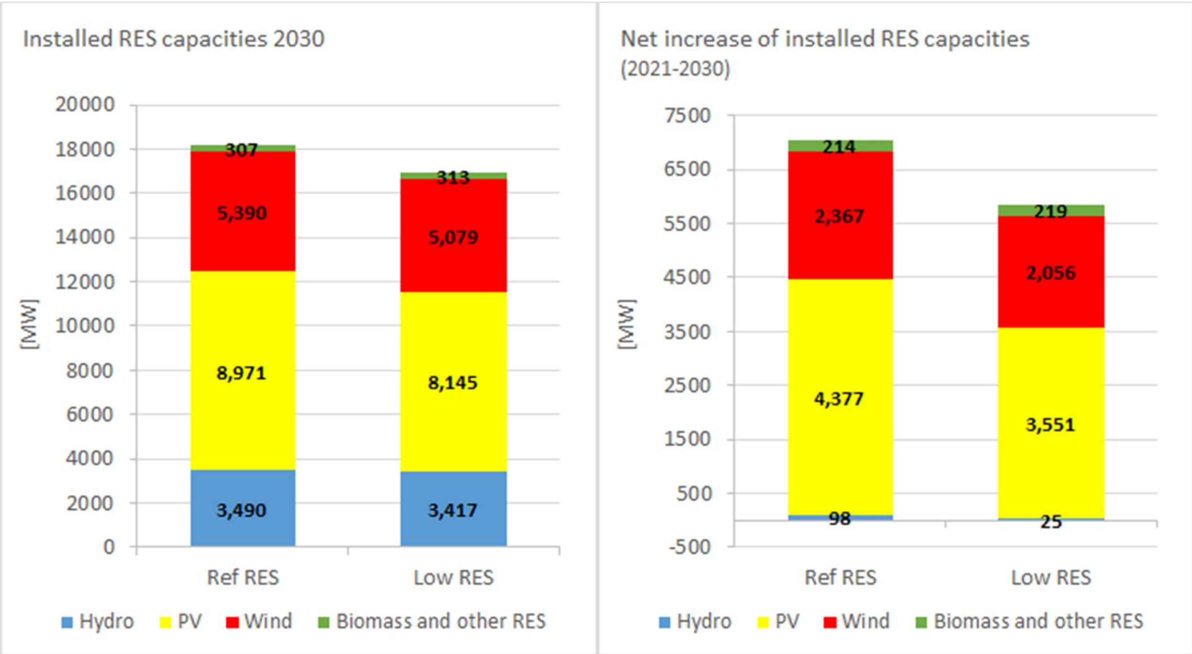
Change in **installed capacity** in the different scenarios is mostly exogenous. The model can install new fossil capacities, but this opportunity is not exploited, as the new exogenously included Mytilinaios natural gas plant with 826 MW capacity and the Ptolemaios V with 660 MW capacity are sufficient and can replace outgoing capacities to satisfy a growing demand for electricity. The continuous phase-out of coal and lignite capacities ends by 2030 in the model (by 2028 in the 2nd draft of the NECP), with a remaining capacity of only 660 MW (the new Ptolemais V power plant) in all analysed scenarios. Renewable capacities increase from a total of 11.1 GW in 2020 to 18.2 GW in 2030. The resulting capacity in different years under different scenarios is shown in Figure 17. The base year for the modelling is 2018, therefore the results shown for 2020 are modelled results.

Figure 17: Installed capacity by type in 2023, 2025 and 2027 in Greece



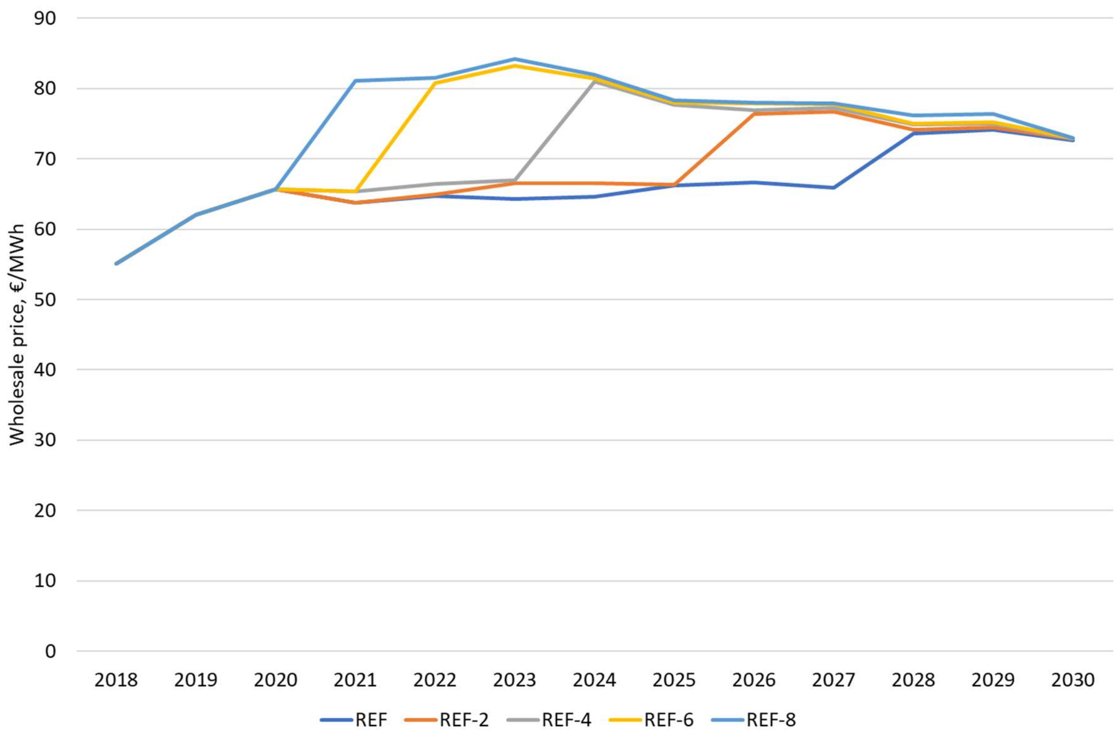
The reference (Ref RES) scenario on RES uptake results in a total of around 18.2 GW RES capacity in 2030, with solar and wind dominating. This would require the net addition of almost 7.1 GW capacity in the next decade, with more than half of the capacity increase coming from PV. In the Low-RES sensitivity variant cumulative RES capacity reaches only 16.9 GW by 2030, with capacity additions at 5.9 GW within the forthcoming decade.

Figure 18 Total installed RES capacity (left) and RES capacity increase (right) in the reference (Ref RES) scenario and Low-RES sensitivity analysis in 2030 in Greece



The Reference case projects an upward **wholesale price** development in Greece, where the price level increases to 65 EUR/MWh level by 2020 from 60 EUR/MWh in 2018, and to 75 EUR/MWh after 2028. This trend is mainly driven by the increasing ETS carbon value pathway and to a lesser extent rising natural gas prices. Early coal/lignite phase-out adds an additional 10-15 EUR/MWh price increase to the reference wholesale price development. The price increase happens almost in parallel with the timing of the lignite phase-out: price peaks appear with the starting years of the phase-out followed by a diminishing difference to the reference price path. As most lignite plants would close down by 2028, the difference in the price levels disappear by that year, from which point on all scenarios converge to a 75 EUR/MWh level. This price increase has various impacts on the electricity system. It will probably transmit to the end user prices as well, but at the same time the higher wholesale price level means a push for further RES deployment, as even more renewables could become competitive at the higher price level. This will clearly be the case as the successful bids for wind and PV in the latest auctions, held in December 2019, were in the 54-58 EUR/MWh range. The following figure illustrates the wholesale price development in Greece under the various lignite phase-out scenarios.

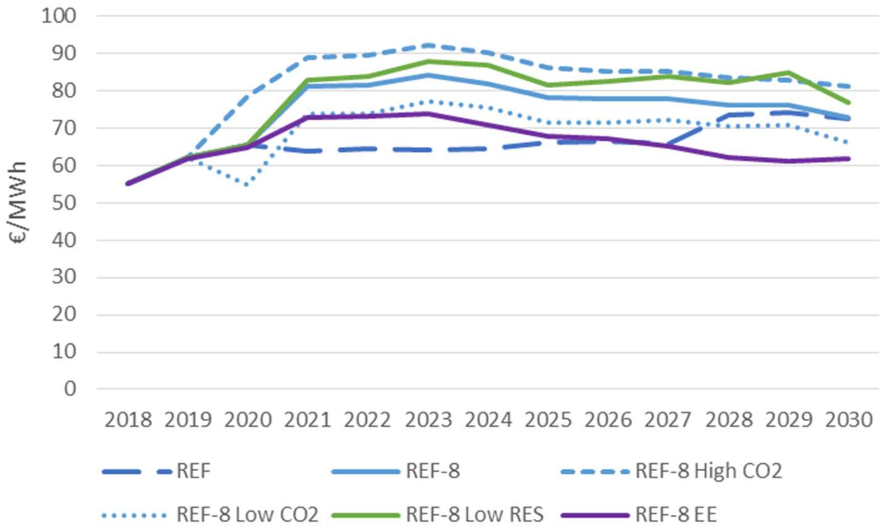
Figure 19 Wholesale electricity prices in REF and early phase-out scenarios in Greece



Wholesale price sensitivity was also assessed for several parameters. The sensitivity analysis indicates that there are ways to reduce wholesale prices, to offset some of the price increase resulting from early lignite plant closure.

The most important instruments is reducing electricity demand. Since the reference scenario demand projections were made before the covid-19 epidemic, it is likely that a reduced demand scenario more accurately reflects expected demand growth during the next few years. A sensitivity analysis was prepared where instead of assuming demand in line with national documents, it was assumed that demand would be consistent with the 32% RES, 32.5% EE targets for 2030 modelled using PRIMES. Lower demand represents a 1.1% decrease instead of stagnating and also lowers wholesale prices significantly, demonstrating the importance of lowering demand in reducing prices. The temporary hike in wholesale prices can be reduced to 9 EUR/MWh, and over the medium term, after about 4-5 years, the price impact of an early phase-out disappears in the lower demand scenarios. By 2030 the scenario with early phase-out and lower demand combined results in a lower wholesale electricity price by 11 EUR/MWh than the reference scenario. This can be seen in Figure 20.

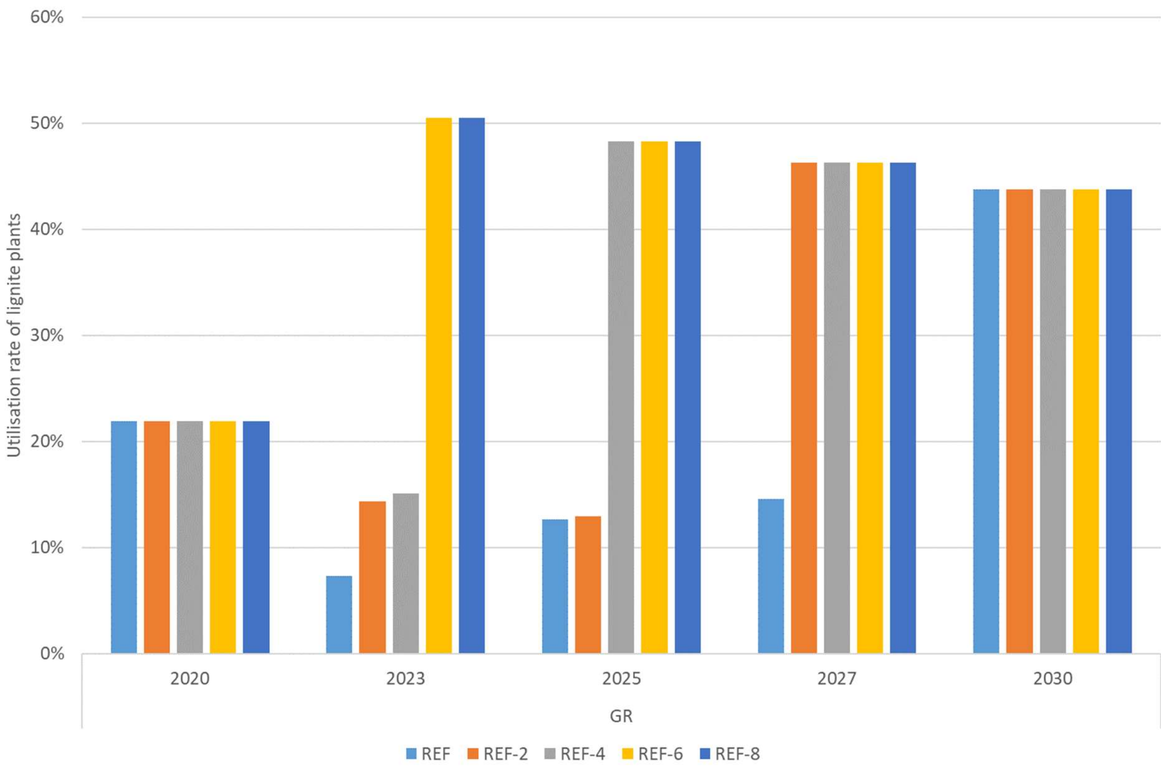
Figure 20 Price impact of CO2 price levels, lower RES penetration and lower demand in the REF-8 scenario in Greece



The Low-RES scenario shows that RES share is negatively correlated with the wholesale price increase; therefore an increase in RES share can reduce prices.

Modelling results confirm that **utilisation rates** of the Greek lignite plants will be below economically viable levels in the early 2020s, and will stay at this sub-optimal level, if no early retirement takes place. The 20% utilisation rates projected for 2020 further drop by 2025 in the reference scenario, while in the faster phase-out scenarios the utilisation rates improve due to the reduction of lignite capacities. Remaining plants would benefit from the reduced supply, and in addition the higher efficiency Ptolemais V plant can gain further market share in this situation. The share of lignite-based electricity production within total domestic power generation is around 4% by 2030 in all analysed scenarios.

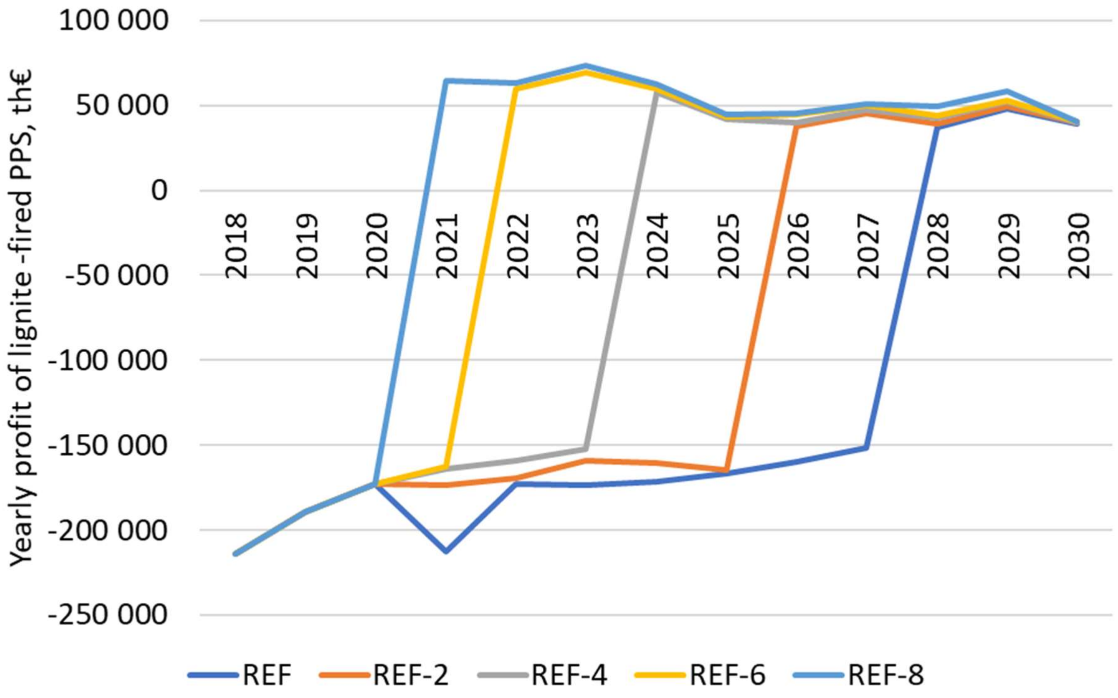
Figure 21 Utilisation rates of lignite power plants in Greece



Profits of lignite plants (defined as: revenue from electricity production – variable costs - yearly fixed costs) are negative in almost all years in all the analysed scenarios - with the exception of the first half of the 2020's years in the more ambitious scenarios - due to their high yearly fixed costs (without accounting for the many forms of support provided for these plants currently by the government). From a strictly economic point of view these plants will most likely close down without any regulatory intervention if government support ends.

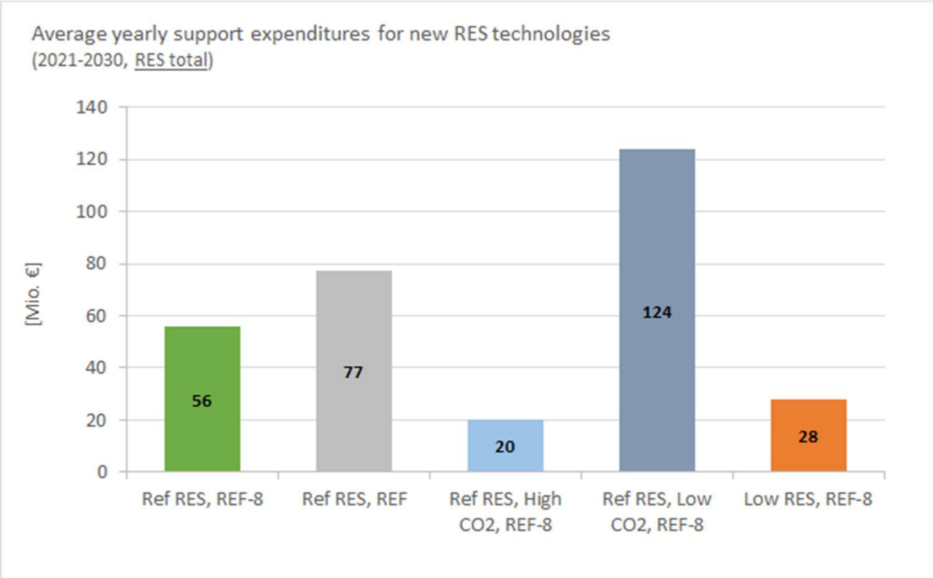
Consumers would face up to EUR 560-650 million **welfare** loss in the most severe phase-out scenarios (REF-8, REF-6) for few years (2021-2023), which loss goes down significantly afterwards. (see tables 34-37 in Annex 2) This is lower than the current level of support for lignite power plants, estimated at close to EUR 900 million, which could be rechannelled towards protecting vulnerable consumers. At the same time remaining producers and network operators would face significant welfare gains due to increased profitability and more intensive use of network elements in the next decade. Producer welfare gains would reach EUR 460-515 million, while rent change would reach above EUR 32.6 million. This means that if the remaining producers and closed lignite plants are in the same ownership, considerable compensation takes place through the producer welfare gains of remaining plants, implying that compensation for early closure of power plants is not required. If ownership is separated for the closing and remaining plants the situation becomes more complex. TSO rents could be used to improve the interconnectivity between countries, or lower network tariffs for end users to reduce the negative impacts of the price increase on consumers.

Figure 22: Aggregated yearly profit of the lignite-fired PPs in Greece



Total yearly average **investment in RES capacity** of about EUR 908 million is needed in the next decade in the reference scenario for future RES deployment (Ref RES), with corresponding yearly support expenditures at EUR 77 million on average over the next ten years under reference conditions concerning coal phase-out (Ref RES, REF). This support level is significantly lower than current support enjoyed by lignite plants. Support needs for new RES depend on the carbon price as well as on the timing of the lignite phase-out: a more ambitious phase-out policy would result in EUR 56 million (Ref RES, REF-8) - and only in EUR 20 million if combined with a high carbon price trajectory (Ref RES, High CO2, REF-8). Both an early phase-out of lignite and high CO_2 prices reduce the required RES support through the increasing wholesale prices which allow RES investors to recover the cost of their investment at lower support levels. At a given RES penetration level consumers must either face a combination of lower electricity prices and a higher support element, or a higher electricity price and a somewhat lower support element. In the reference (REF) scenario the total support for new RES is around 2.8% of the wholesale electricity price by 2030 if paid by all consumers equally, and it amounts to 2.6% if an earlier coal phase-out is presumed (REF-8); the difference is insignificant.

Figure 23 Average yearly support expenditures for new RES capacities in Greece in 2021-2030



Important changes in the **trade flows** could be observed in Greece during the modelled timeframe. First, the rather high net value of imports for 2020 seems to be confirmed as in the first 10 months of 2019 net imports reached 7949 GWh compared to 5472 GWh for the same 10-month period of 2018, and 6274 GWh for the entire year of 2018. The overall net import level shows a decreasing trend in both the Reference and in the strongest phase-out (Ref-8) scenarios. Import is reduced from all directions except from North Macedonia; the country increased its exports to Greece due to its carbon price advantage. Imports from other directions decrease, and Greece starts exporting electricity to Bulgaria after 2025, mainly due to its stronger RES uptake, which confers a competitive advantage in an environment of increasing gas prices and a high carbon price. The stronger interconnection with Bulgaria allows for increased exports.

Table 7 Net electricity import for Greece in 2020, 2025 and 2030 under the REF and REF-8 scenarios

Net import from, GWh/y	REF			REF-8		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
BG	4 362	175	-6 053	4 362	-2 978	-6 090
IT	3 374	2 536	2 990	3 374	3 710	3 028
MK	1 783	1 724	4 017	1 783	1 996	3 978
AL	1 713	1 491	1 127	1 713	1 801	1 155
TR	1 174	1 116	1 019	1 174	1 109	1 019
Total net import (GWh/y)	12 405	7 042	3 100	12 405	5 637	3 091

The planned RES investments in accordance with the draft NECP levels and the planned new gas fired installations in the region can help maintain **system adequacy** in Greece over the next decade. The adequacy modelling carried out with the EPMM unit commitment model shows that reserve capacity needs can be maintained, with sufficient level of spinning and non-spinning reserves staying in the system in Greece. Minimum 5% reserve capacities are available compared with consumption in both downward and upward regulation in all modelled countries. The energy not supplied (ENS) value shows no increase in the assessed two years (2023 and 2029) in the case of phase-out, as the available generation capacity and interconnection levels are sufficient to avoid problems. The change in RES curtailment is important as Greece is projected to have high growth in weather dependent PV and wind capacities in the various scenarios. There is a slight increase in the RES curtailment value in Greece, but its value remains low at 0.037%, due to the increased interconnection level with Bulgaria, which helps to avoid higher curtailment levels.

4.2 Just transition

Greece has three NUTS-3 regions where lignite mining and/or lignite-based power production is relevant and has a role in the socio-economic systems. The Amyntaio mine and plant are located in the Municipality of Amyntaio in the Region of Florina (NUTS-3 Region of Florina) with the Meliti plant and its associated mines in Vevi and Achlada located in the Municipality of Florina of the same region. The Ptolemais basin mines and plants are located in the Municipalities of Eordaea and Kozani of subregion of Kozani (NUTS-3 Region of Grevena-Kozani). The Megalopolis plants and mines are located in the synonymous Municipality of Megalopolis in the subregion of Arcadia (NUTS-3 Region of Argolida-Arcadia).

In the three Greek NUTS-3 regions affected, as shown in the figure below the number of employees of mines and lignite power plants is 5 765, with around 40% of them older than 55 years very close to retirement and thus not directly affected by the coal phase-out to take place in the next 3-5 years. The number though is increased substantially if one takes into account the approximately 7000 indirect employees of enterprises connected with the activity of the lignite mines and plants.

Table 8 Expected job losses from a coal phase-out and government payments to compensate for lost jobs, Greece

	Number of jobs lost		Financing needs (thousand EUR)
	< 55 years	55 years or older	
power plant	1305	670	226 885
mine	2200	1426	
Total direct jobs	3505	2096	

Indirect jobs	7 010	257 516

In terms of expected economic impact of the phase-out, there are significant differences found between the three regions affected, namely the subregion of Kozani in the NUTS-3 region of Grevena-Kozani, the region of Florina in the homonymous NUTS-3 region and the subregion of Arcadia in the NUTS-3 region of Argolica-Arkadia.

The Florina region is the poorest of the three. There is very little economic activity beyond the mines and plants. The Mining/Electricity sector VA (EUR 221 million out of a total of EUR 739 million in 2016) is the highest with the Construction (EUR 89 million) and Manufacturing (EUR 30 million) ones almost entirely connected with the lignite activity. These three are responsible for over 45% of the VA. The next largest Sector O-Q (Public administration and defence, compulsory social security, education, human health and social work activities at EUR 141 million) is mostly dependent on public funds. This only leaves Agriculture (at EUR 78 million) as a viable target for further development although the climate and land are not very conducive to large output increase. To attract activity in productive sectors (manufacturing and construction) where there is a skill match would require substantial development incentives.

The exact same picture is found in the Arcadia subregion of the Argolida-Arcadia NUTS-3 region where Megalopolis is located with a 37% lignite related activity. Here the presence of the University of Peloponnese main campus in the neighbouring Municipality of Tripolis may provide opportunities to develop high tech enterprises possibly associated with the University. Here though the total number of employees involved is relatively small (ca 1000) with about a third very near retirement and some to be transferred to the collocated NG station which will both lose some staff to retirement and will increase its capacity from 500MW to 814MW.

The third affected region is in the Kozani subregion of the Grevena-Kozani NUTS-3 region. Of the three regions, Kozani has the most significant lignite production and average installed capacity, as well as the highest number of employees in the coal sector. The Kozani-Ptolemais urban area is a local hub of economic activity and the home of the University of Western Macedonia and the Polytechnic of Western Macedonia. Nevertheless, the comparative importance to the local economy of the lignite activity is at the same level (51% lignite related activity) so that it faces the same development hurdles as the other two regions. This region also had the highest decrease in GVA in the period 2006-2016, therefore the absorption of redundant coal workers may face significant challenges. The Kozani subregion, unlike the other two, is well aware of the difficulties ahead and has taken the lead in trying to devise a strategy and an implementation plan to move forward, an effort that would benefit from external funding.

It is estimated that a total investment of around EUR 1.6 billion is required to offset the economic losses in coal regions resulting from the phase-out. In all three regions there are plans by the Public Power Corporation (PPC) for the construction of large PV plants (over 250MW total) as well possible construction of a NG plant to take advantage of the infrastructure. This would provide a welcome assist to the transition process and reduce the required investment in other sectors to offset GVA losses. When including the figure required for compensating for employment losses, the total funding required is EUR 2.1 billion. Some of this, if made in productive investment, may come in the form of loans and other financial instruments.

4.3 Policy conclusions

On 27 September 2019, after the launching of this work, the Greek Government announced at the UN Climate Summit that it intends to decommission all lignite plants by 2028. This announcement was to be reflected in the final Greek NECP to be submitted to the European Commission (EC) by the end of 2019. Indeed, on 28 November 2019, the Ministry of Environment and Energy (YPEN) put up for public consultation a modified version of the Greek NECP which ups all targets for 2030; it increases the 32% GHG emissions reduction target contained in the draft NECP to 42%, the target for the improvement of energy efficiency from 32.5% to 38%, and the target for RES from 31.5% to 35%. The latter target implies a 62% RES share in electricity production, increased from a 56% value contained in the draft NECP. The scenarios examined in this study have taken this announcement into account as regards lignite plant closure with the reference scenario for Greece assuming that all plants will cease operation at the end of 2028.

The new enhanced NECP indeed calls for the decommissioning of all lignite plants by 2028 and goes further by calling for the decommissioning of 1700MW out of the 3904MW currently in operation by 2022 and an additional 2300MW by 2024 leaving after 2025 only the 615MW(net) Ptolemais V plant currently near completion to operate until 2028. This is the case of an accelerated phase-out scenario Ref-4 by a year or so if the business plan announced on 17 Dec 2019 which calls for the decommissioning of all plants except Ptolemais V by the end of 2023 is applied. The more ambitious scenarios Ref-6 and Ref-8 differ only in that the operation of the 5 Ag. Dimitrios units and the Meliti plant also cease immediately. This though is likely to create a possibly critical power shortage as the new Mytilinaios NG plant under construction will not be operational and the electricity demand in the mainland grid will increase as Crete will be connected by 2022 in view of the obligatory cessation of operation of its oil units because of environmental constraints.

It is thus instructive to **compare the results of this modelling with the corresponding ones of the enhanced 2nd version of the NECP** but for the electricity sector only.

The estimated final electricity consumption is approximately the same in both at about 56TWh. This is to be covered by gross inland production plus net imports minus grid losses and auto-consumption (of about 4150GWh). The ETS allowance price trajectories considered differ somewhat, with the NECP assuming a smooth increase from today's price of about 25 EUR/tCO_2 to 31.3 EUR/tCO_2 in 2030 and this study adopting a constant 35 EUR/tCO2 after 2025, a difference which though is reflected in the wholesale price. At the same time the NECP assumes an NG price 10% higher in 2020, increasing to 22% by 2030. This is also reflected in the wholesale price.

The allowance price increase above 25 EUR/tCO_2, as shown in the results of this and other very recent studies, leads to existing lignite plants in Greece accumulating operating losses from 2018 on, which calls for their early decommissioning even on economic terms alone. It seems that this has been realized by PPC, their operator, and agreed by the Government and has led to the very early retirement of all existing plants. Besides the increase of the operating cost due to the allowance price rally, this is also the result, as is shown by this study and confirmed by the NECP projections, of their very low future utilization (load factors of around 10-15% which implies high numbers of start-ups with large associated costs). This low utilization is brought about by competition from both NG plants with their higher efficiency and low fuel and capital costs and the decrease of RES LCOE as evidenced by the offers in the RES installation auctions in Greece in 2018 and 2019.

Of interest is also the fate of the Ptolemais V lignite plant currently under construction at an initial cost of EUR 1.39 billion to operate from 2021 until 2028. The results of this study indicate that it would be profitable if capital costs are not taken into account, but will operate with only a ca 50% utilization rate as opposed to a rate of over 193% (7400hr/yr) inscribed in the NECP. In either case, it is clear that the capital costs will not be recovered. A number of options are currently under consideration including conversion after 2028 to NG, biomass or co-firing with solid waste. Its fate remains to be seen.

A crucial consideration in the effort to early de-lignitisation is its effect on **wholesale electricity prices**. The wholesale price is clearly affected by the allowance price, the production mix and price of imports. It is interesting to note that both in this study and in the NECP the wholesale price behaviour is similar, showing an initial increase at around 2023-2024 and a gradual decline later on toward 2030. They differ though substantially on the level which is, in 2030, ca 75 EUR/MWh for this study and 96 EUR/MWh in the NECP. One possible reason, besides the NG price difference, for the higher price in NECP is the absence of an integrated consideration of the coupling of markets which is an essential part of the EU energy package in which a limit in the price differential of over 2 EUR/MWh is under consideration.

Net imports in the modified NECP decrease monotonically reaching 4578GWh in 2030 (to be compared to 3091GWh in this work), as it does not take into account the dynamic and close interaction with mainly Bulgaria and the rest of the neighbouring Balkan countries. This point is important because one of the main conclusions of this modelling work is the importance of interconnections to smooth price spikes, enable higher utilization and lower curtailment of RES, enhance grid stability and increase security of supply. This is clearly evident for Greece and Bulgaria as the interconnection between them is well on the way to increase its capacity and would result, as the modelling clearly shows, in an almost full elimination of wholesale price differentials between the two countries. The planned upgrading of the interconnections with both Albania (Mourtos-Bistrica) and North Macedonia (Meliti-Bitola) will further enable electricity exchanges although the added cost of allowance price would need to be addressed possibly at border as these modelling results show a net import of near 11TWh from the four non-EU countries and a net export of 6TWh to Bulgaria by 2030.

If the **economic basis** for the early retirement of the lignite plants is acted upon, the production gap that it will create can be covered by increased load factors of the existing NG plants together with the new ones already under construction or in the late permitting phase and by RES. In this era of very low NG prices, the NG plants have a competitive edge as their LCOE can be even lower than that of wind and PV. There is then a real possibility that the production gap that results from the lignite plant retirement would be filled by the NG plants leaving limited room for the RES units which are estimated both in the NECP and in this study to reach at least 19GW by 2030. This tendency of the NG units to fill the gap is clear in the revised NECP which includes 18.3TWh of NG production as compared to only 10.5TWh in the previous version in which by 2030, 2700MW of lignite were still on-line. In view of the long-term EU target of reaching near zero emissions by 2050, to ensure that RES installation isnot hindered, it is imperative that this development does not happen. A necessary condition for this is that priority dispatching of RES is maintained and the increase in storage facilities to assure minimum curtailment of RES generation be supported both as regards administrative aspects and financing costs.

Besides agreement of this study and the revised NECP for the total RES to be operating by 2030 at around 19GW, there is near agreement on the amount of **investment needed** for the period 2020-2030 which in this study is ca EUR 8.1 billion and in the NECP EUR 8.9 billion cumulatively for this 10-year period.

The accelerated retirement of the lignite units will result in **stranded investments** for PPC. These stranded investments include only three plants (Ag. Dimitrios V, Megalopolis IV and Meliti) as the others will have exceeded 40 years of service. These three have 30 years of operation left in total beyond the decommissioning dates of the revised NECP. Their operation past 2024 for the additional cumulative 40 years under current EUA allowance price would result, at an allowance price of 30 EUR/tCO_2, in EUR 898 million operating losses of which EUR 428 million from Megalopolis IV and EUR 172 million from Meliti as against a book value on 31 December 2018 for Meliti of EUR 130 million and of EUR 140 million for Megalopolis III & IV (PPC. 2019a). Thus, after 2024, only the Ag. Dimitrios V unit might have some stranded value. This is not the case though for the investment in the mines for which the book value as of 31 Dec 2018 was EUR 1316 million but in which the value of the lignite in situ should not be counted as they were assigned to PPC by the Greek State at no cost. If, for reasons of security and emergencies, some of these units and most likely Ag. Dimitrios V and Meliti are kept as cold or spinning reserve after 2023, some remuneration might be negotiated to cover some of the stranded cost.

In summary, the results of this study provide strong evidence to support the ambitious plan of the Greek Government to decommission on economic grounds all lignite plants as early as possible so that by 2024 only one would be left in operation which will also close down in 2028.

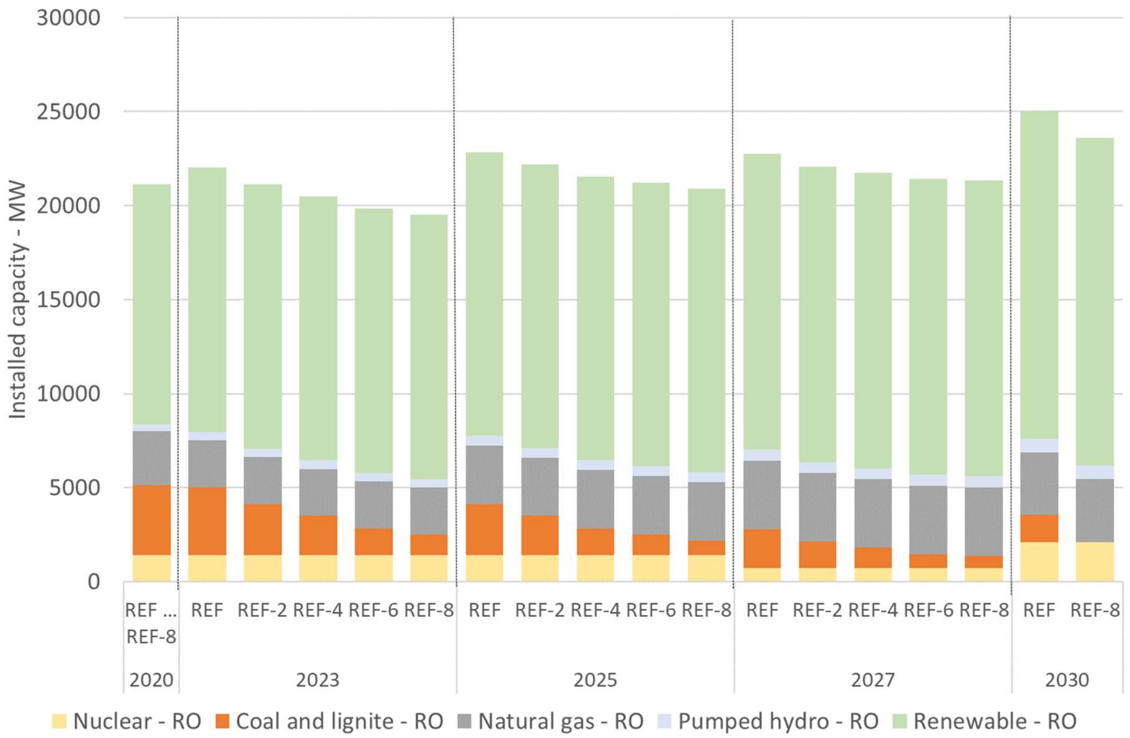
Finally, it should be stressed that the expected retirement of the lignite plants by 2028 according to the Government pledge would entail large upheaval in the local communities where the plants are located. Despite warnings in the past, planning for a **Just Transition** of these communities to the post-lignite era has not progressed enough so as to propose new viable and substantial economic activities to replace lost income and more importantly to identity, let alone secure, the funds that would be needed to support the communities throughout the transition period. It is imperative that this planning is completed immediately, that programs to address the social problems that will result, and that funds are secured including through a robust Just Transition Fund financed from the MFF, go hand-in-hand with the plan to retire the lignite plants by 2028.

5. Romania

5.1 Modelling Results

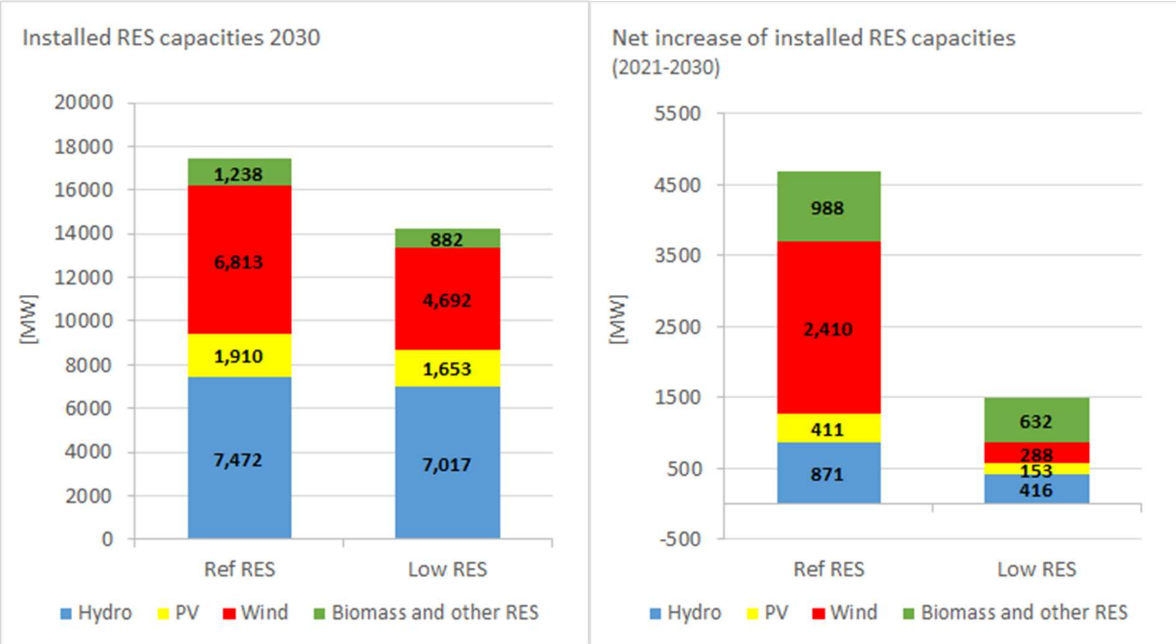
Change in **installed capacity** in the different scenarios is mostly exogenous. The model can install new fossil capacities, but this opportunity is not exploited, as new exogenously included natural gas capacities and one new coal plant are sufficient to replace outgoing capacities to satisfy a growing demand for electricity. More than 1.5 GW new natural gas capacities are planned, thus no further expansion is needed. The continuous phase-out of coal and lignite capacities does not end in all scenarios by 2030; remaining capacities vary between 0 and 1.4 GW from REF-8 to REF scenarios. Renewable capacities increase from a total of 12.8 GW in 2020 to 17.4 in 2030 GW. Although total installed capacity is much higher than the expected peak demand of around 9185 MW in 2022, it has to be noted, that significant part of this capacity (8000 MW) is unavailable for operation due to incidental and planned repairing. This still leaves necessary coverage of peak demand in the system, as network connection amounts to 2500 MW for Romania. The base year for the modelling is 2018, therefore the results shown for 2020 are modelled results.

Figure 24: Installed capacity by type in 2023, 2025 and 2027 in Romania



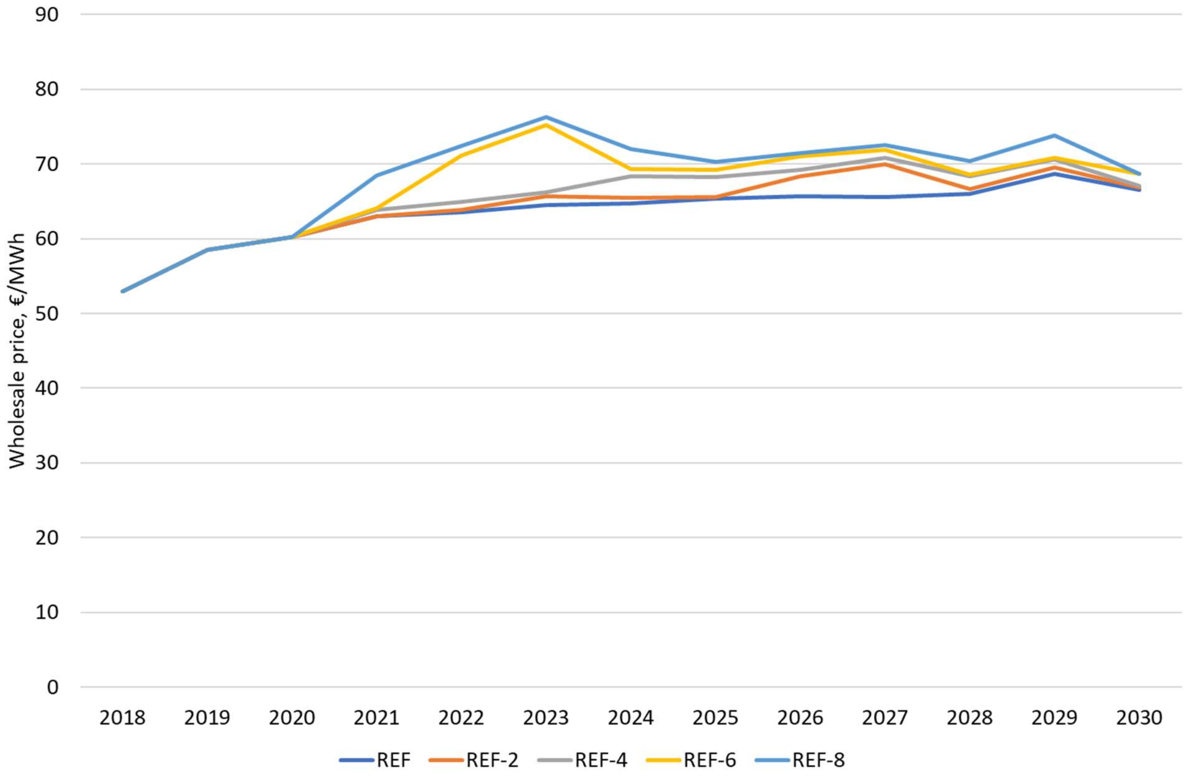
Sensitivity analysis was performed for the RES uptake in the forthcoming decade, with a lower RES deployment scenario (Low RES) analysed in comparison to the reference (Ref RES) case. In the Ref RES scenario, the cumulative RES capacity in 2030 amounts 17.4 GW, with hydro and wind dominating. This would require the addition of almost 4.6 GW capacity in the next decade, with more than half of the capacity increase coming from wind. The Low-RES sensitivity scenario results in a cumulative RES capacity of 14.2 GW by 2030, with a capacity addition at only 1.5 GW.

Figure 25 Total installed RES capacity (left) and RES capacity increase (right) in the reference (Ref RES) scenario and Low RES sensitivity analysis in 2030 in Romania



Early phase-out of lignite has a significant **wholesale electricity price** impact in Romania. However, compared to Bulgaria and Greece the price impact of an earlier phase-out is much smaller, mostly due to the fact that lignite production represents a relatively low share in the country's generation mix, but also as a result of the high level of interconnectivity with the Western markets through the 4MC market coupling. This means that Romania is less exposed to the risk of high price spikes when closing its lignite plants than Bulgaria and Greece. In 2023 there is almost 12 EUR/MWh difference in the reference and the most ambitious phase-out scenario (REF-8). In 2027 the overall increase is lower, 7 EUR/MWh in the highest impact REF-8 scenario. The effect of bringing lignite power plant closure forward by just 2 or 4 years has a much smaller price impact, around 5 EUR/MWh in the most critical years. Similarly to the other two countries, the price levels in the modelled scenarios converge by 2030, as most lignite power plant unit would close by then.

Figure 26 Wholesale electricity prices in REF and early phase-out scenarios in Romania

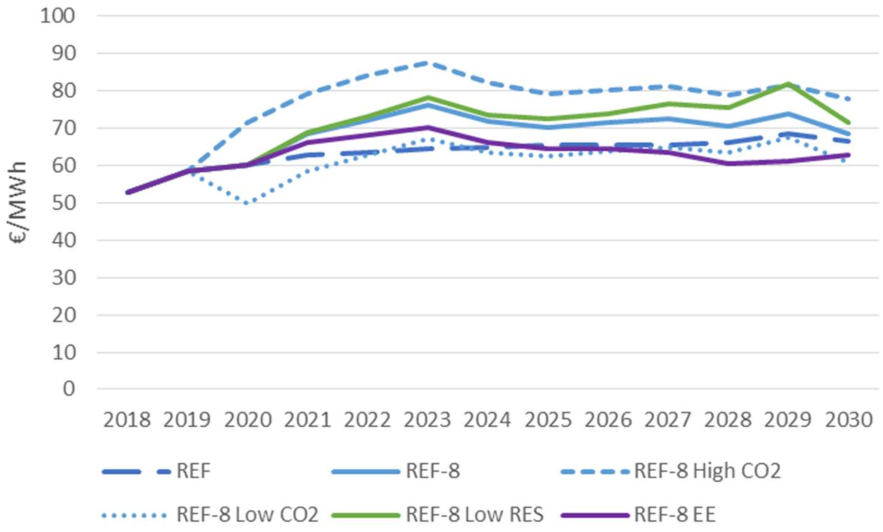


Wholesale price sensitivity was also assessed for several parameters. The sensitivity analysis indicates that there are ways to reduce wholesale prices, to offset some of the price increase resulting from early lignite plant closure.

The most important instruments is reducing electricity demand. Since the reference scenario demand projections were made before the covid-19 epidemic, it is likely that a reduced demand scenario more accurately reflects expected demand growth during the next few years. A sensitivity analysis was prepared where instead of assuming demand in line with national documents, it was assumed that demand would be consistent with the 32% RES, 32.5% EE targets for 2030 modelled using PRIMES. The temporary hike in wholesale prices can be reduced to 3 EUR/MWh, and over the medium term, after about 4-5 years, the price impact of an early phase-out disappears in the lower demand scenario. By 2030 the scenario with early phase-out and lower demand combined results in a lower wholesale electricity price by 4 EUR/MWh than the reference scenario. This can be seen in Figure 27.

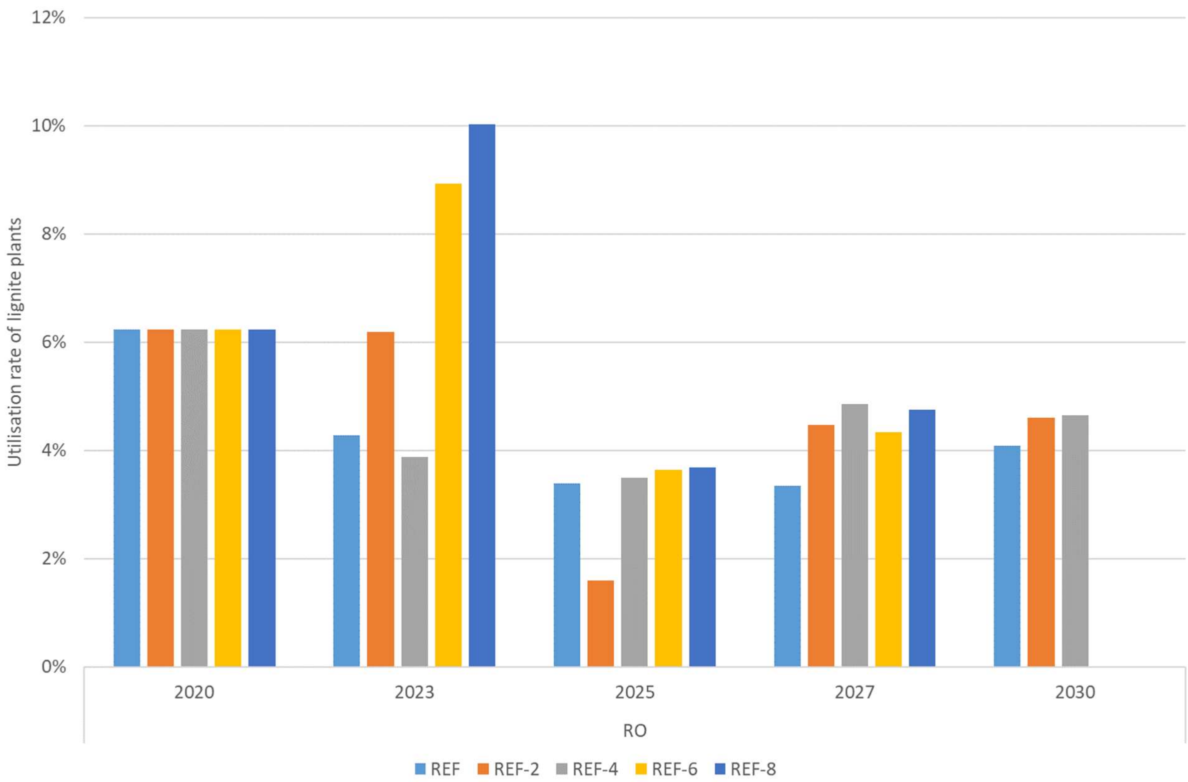
The Low RES scenario shows that RES share is negatively correlated with the wholesale price increase; therefore an increase in RES share can reduce prices. Lower demand significantly lowers wholesale prices, demonstrating the importance of lowering demand in reducing prices: the lower (more realistic) demand projections (instead of a yearly growth rate of 2.9% only 0.8%) result in 5-13 EUR/MWh lower electricity prices in the last 5 years of the modelled period.

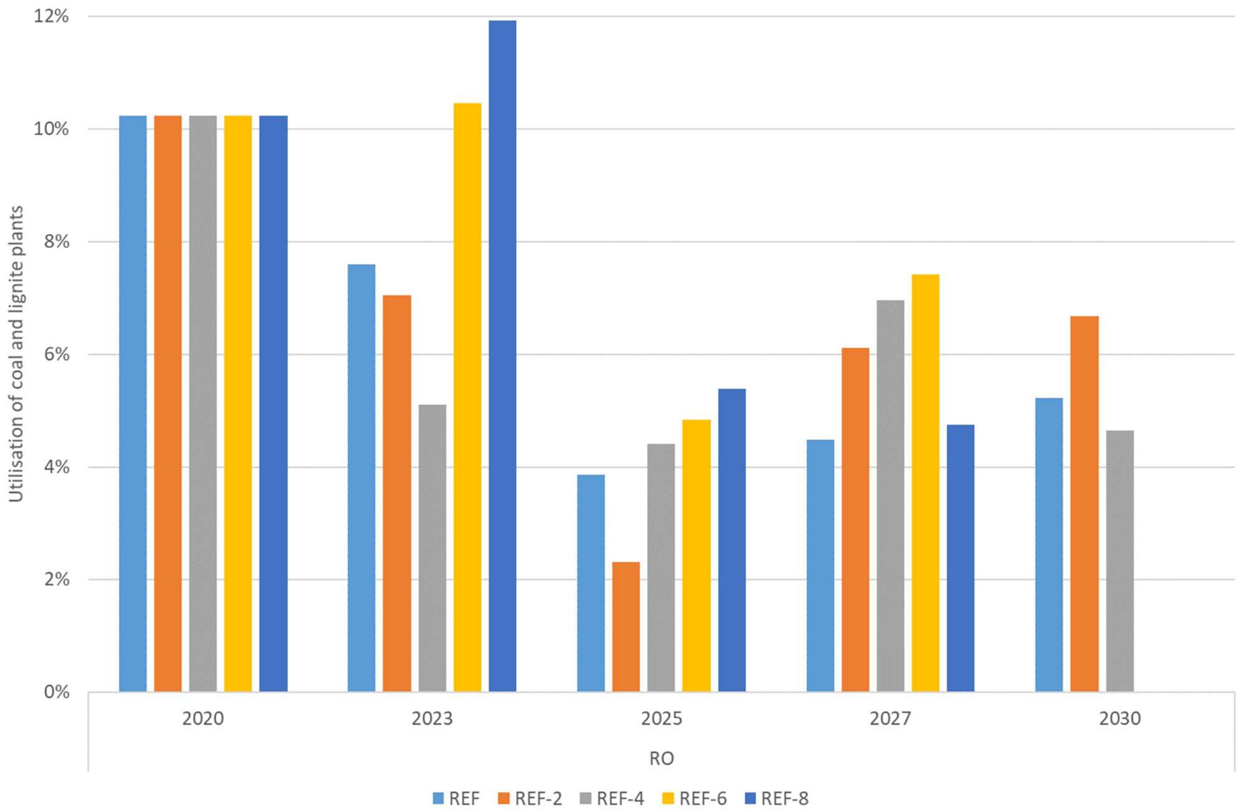
Figure 27: Price impact of CO2 price levels, lower RES penetration and lower demand in the REF-8 scenario in Romania



The explanation of the lower price effect for Romania is presented on the figure below: lignite utilisation rates are already very low. Even in 2020 - the year with the highest utilisation rates - the plants barely exceed 10% utilisation rates on average; this decreases to 4-5% in the reference case from 2025 onwards. With the closure of less efficient/older plants the remaining fleet can perform better on average. The differences, however, are small, the overall average utilisation rate of lignite plants is very low, far below economically viable rates across all scenarios and in all years.

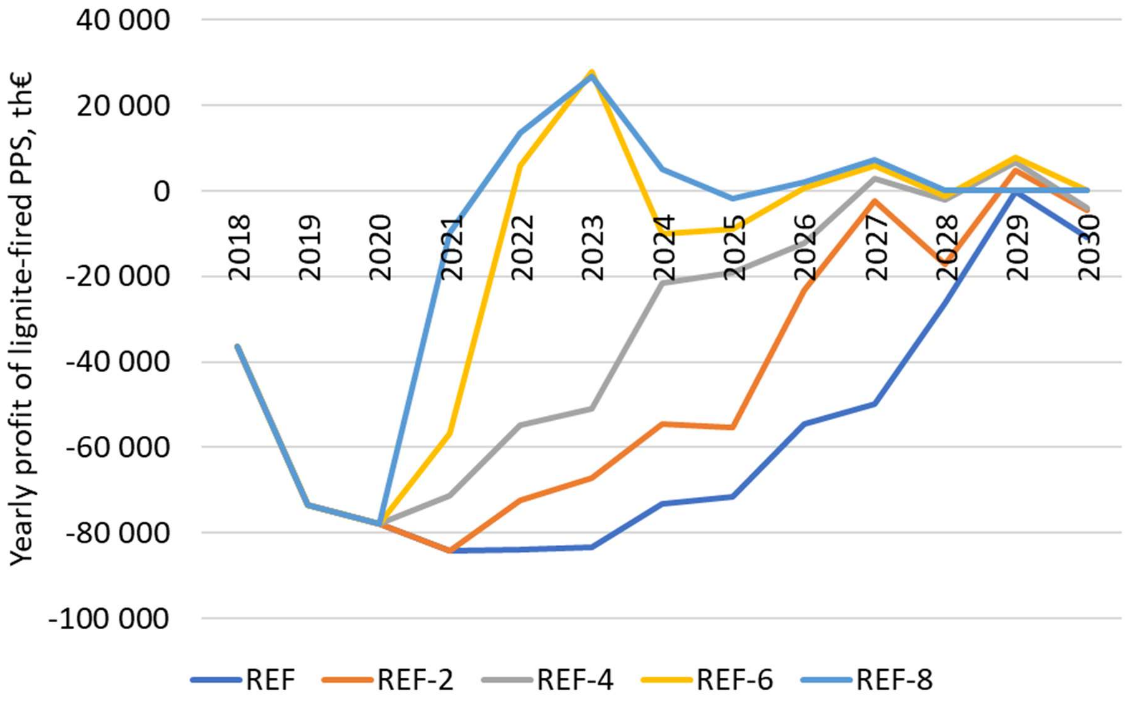
Figure 28 Utilisation rates of lignite (top figure) and lignite and coal (bottom figure) power plants in Romania





This is also reflected in the **profit levels** of these plants: the overall yearly profit level (defined as revenue from electricity production – variable and yearly fix costs) of lignite plants is highly negative until 2025 in the less ambitious phase-out scenarios, and then arrives to close to zero in all scenarios for the last 5 modelled years. Significantly positive profit levels are only realised in the REF-8 and REF-6 scenarios, but only for a couple of years at the beginning of the 2020's. Consumers would face up to EUR 406 million **welfare** loss in the most severe phase-out scenarios (REF-8, REF-6) for few years (2021-2023), which loss goes down significantly afterwards. (see tables 34-37 in Annex 2) Some of the current support to power plants, at EUR 200 million a year, could be used towards compensating vulnerable consumers. At the same time remaining producers and network operators would face significant welfare gains due to increased profitability and more intensive use of network elements in the next decade. Producer welfare gains would reach EUR 337 million, while rent change would reach above EUR 32.6 million, so these benefits at producers would reach substantial levels. This means that if the remaining producers and closed lignite plants are in the same ownership, considerable compensation takes place through the producer welfare gains of remaining plants and compensation for early phase-out would not be required. If ownership is separated for the closing and remaining plants the situation becomes more complex. TSO rents could be used to improve the interconnectivity between countries, or lower network tariffs for end users to reduce the negative impacts of the price increase on consumers.

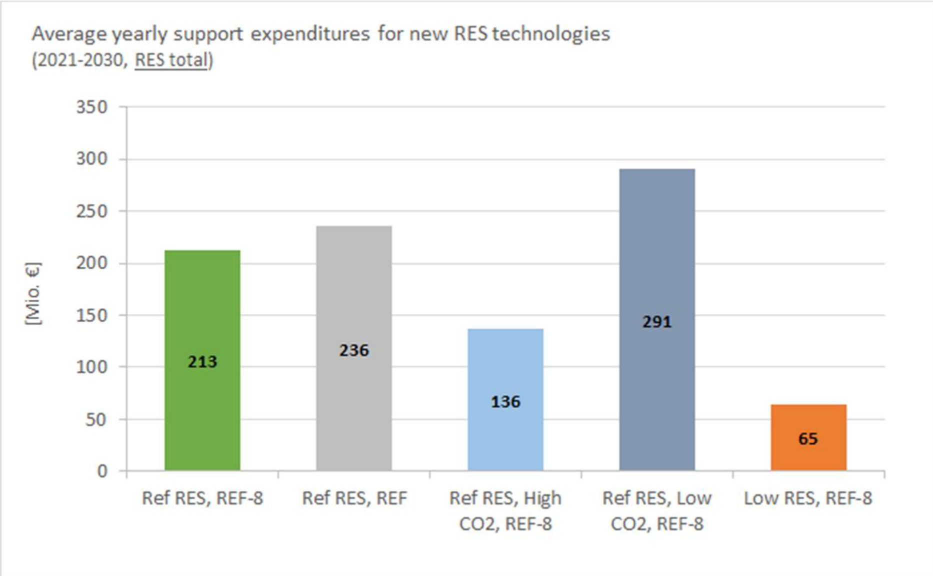
Figure 29: Aggregated yearly profit of the lignite-fired PPs in Romania



Total average yearly **investment in RES capacity** of about EUR 1.1 billion is needed in the next decade in the reference scenario concerning RES use (Ref RES). Support needs for RES depend on the carbon price as well as on the timing of the lignite phase-out: a more ambitious phase-out policy would result in EUR 213 million (Ref RES, REF-8) - and only EUR 136 million combined with a high carbon price trajectory (Ref RES, High CO2, REF-8) - compared to the reference EUR 236 million average yearly support need (Ref RES, REF). These support levels are high compared with levels for Bulgaria and Greece. However, they are around the same level as the annual support planned for lignite plants in Romania based on available policy documents, which will amount to EUR 200 million annually on average over a 10 year period.

Both early phase-out of lignite and high CO_2 prices increase wholesale electricity prices, thus reducing the required RES support. A given RES penetration level consumers must either face a combination of lower electricity prices and a higher support element, or a higher electricity price and a somewhat lower support element. In the reference scenario (REF) the total RES support is around 10% of the wholesale electricity prices by 2030 if paid by all consumers equally, and is 9.3% in the early phase-out scenario (REF-8).

Figure 30 Average yearly support expenditures for new RES capacities in Bulgaria in 2021-2030



Trade flows overall are not strongly impacted by the phase-out of lignite in Romania. There is a massive change in flow direction by 2025 and 2030 between Romania and Serbia, but this happens in all scenarios.

Table 9 Net electricity import for Romania in 2020, 2025 and 2030 under the REF and REF-8 scenarios

	REF			REF-8		
Net import from, GWh/y	**2020**	**2025**	**2030**	**2020**	**2025**	**2030**
BG	2 213	-763	-1 214	2 213	-1 557	-1 165
HU	-493	-2 509	825	-493	-1 704	1 029
RS	-799	4 733	4 159	-799	4 903	4 581
UA_W	1 613	188	63	1 613	365	-46
Total net import (GWh/y)	2 534	1 649	3 833	2 534	2 007	4 399

System adequacy is maintained in the next decade. The adequacy modelling carried out with the EPMM unit commitment model shows that reserve capacity needs could be maintained, sufficient level of spinning and non-spinning reserves stay in the system. The 5% minimum reserve levels are available in both downward and upward regulation in Romania. The energy not supplied (ENS) values showed no increase in the assessed two years (2023 and 2029) in the case of phase-out, as the interconnection levels, new RES and gas fired capacities were sufficient to avoid any growth in ENS. RES curtailment shows no increase in Romania.

5.2 Just transition

In Romania there are two key regions that will be affected by the transition away from coal and lignite. Altogether in the two affected NUTS3 regions, Gorj and Hunedoara, the number of employees is 13,917, of which 10,017 are working in mines and 3,900 in power plants. Around 26% is older than 55 years (those will not be affected by the coal phase-out). Altogether with the jobs in the indirect sectors, the affected number of employees is around 36 750. Of the two regions, Gorj has almost ten times more coal mining and electricity generation capacity.

Table 10 Expected job losses from a coal phase-out and government payments to compensate for lost jobs, Romania

	Number of jobs lost		Financing needs (thousand EUR)
	< 55 years	55 years or older	
power plant	2 352	409	112 086
mine	5 380	935	
Total direct jobs	7 732	1 344	
Indirect jobs	19 332		108 743

The current economic situation shows that the two relevant regions are equally affected. The level of the total GVA is around the same in the two regions, however, economic growth rates are much higher in Gorj than in Hunedoara, therefore Gorj has a better ability to absorb workers made redundant by the phase-out.

The Jiu Valley, Romania’s coal region with a long tradition of hard coal mining, situated in NUTS3 Hunedoara County, is extremely affected region by the transition. Opportunities in farming exist for workers made redundant by the transition. The potential of renewable sources of energy, especially wind, may also be a development factor, continuing to maintain Jiu Valley on Romania's energy map. The thermal rehabilitation of the low efficient building stock in the Jiu Valley also provides an excellent opportunity for power plant workers, miners as well as employees and service. There are also several companies involved in the food and textile industry, wood processing and furniture industry. Many of these companies already have traditions, experience and strong market position and may be able to absorb a part of the affected workforce. The manufacturing of electronic and optical components is an important link in multiple value chains, especially considering the upsurge in investment in the car industry in the region and in the vicinity, having the potential to become an important supplier both for big investors in the region and for attracting new opportunities in the area. Tourism (including agro-tourism and nature tourism) is an area of potential for growth that Jiu

Valley can count on in order to ensure a fair transition to a diversified economy, especially due to the potential of the natural environment and cultural heritage.

In Gorj county, agriculture and industry are the most important employer sectors. In addition, construction, transport and storage make up a relatively significant share of the local economy. The production and supply of energy is responsible for 13.7% of industrial employment and 3% of total employment. Most coal workers are expected to be retired early following the phase-out due to their high age, and those who remain in the labour market may transfer their skills of mining/PP mechanical and electrical technicians to the renewable energy and electricity distribution sector. Other opportunities may exist in the energy efficiency, wood and furniture industries.

It is estimated that a total investment of around EUR 480 million is required to offset the economic losses in coal regions resulting from the phase-out. When including the figure required for compensating for employment losses, the total funding required is EUR 600 million. Some of this, if made in productive investment, may come in the form of loans and other financial instruments.

5.3 Policy conclusions

The critical question for the Romanian decision-makers in the mid-term perspective (i.e. 2025) is how to sustain a coal- and lignite phase-out that is as swift as possible while also ensuring security of supply, system adequacy, and an acceptable electricity price.

According to the results of the quantitative modelling, most lignite and coal plants in Romania will be retired on financial considerations within the next few years. Nonetheless, an accelerated phase-out calendar is also possible. From the viewpoint of **the yearly profits of the lignite- and hard coal-fired PPs** in Romania, the modelling shows that the profits are negative in almost all cases, both in the low and high RES scenarios. The fact that the losses are minimised in the scenario of fastest lignite phase-out sends a clear message to the policy makers: the lowest losses are made under the most ambitious phase-out scenarios. The investments needed to comply with the new IED requirements will further erode the viability of lignite- and coal-fired PPs.

On the other hand, the most ambitious phase-out scenarios are associated with the highest and steepest increases in **wholesale electricity prices**, which may, in turn, lead to some public acceptability challenges. It should be noted, however, that due to the market coupling of Romania with Hungary, Slovakia and Czechia, these increases would be less dramatic than in the cases of Bulgaria and Greece. Besides, the modelling shows that this increase can also be minimised through a higher integration of RES in the electricity mix.

Furthermore, these dynamics of the wholesale electricity prices are different if the model makes more realistic assumptions on the Romanian electricity demand in 2030 than the data provided by the draft NECP’s consumption projection, used for the three member states of the SEE region. For

Romania, the credibility of the NECP figure has been argued to be problematic. If the input data is changed to the SEERMAP[10] projection, which offers much more realistic data for a low RES, REF CO_2 price scenario, the wholesale price only increases to more bearable levels between 2023 and 2030, with a difference of about 10 EUR/MWh starting in 2028. Therefore, a more realistic assessment of the country's power load over the coming decade shows that the Romanian Government may afford politically to be more ambitious in its coal phase-out planning. All these considerations and their associated trade-offs should be used for striking a balance between the minimisation of losses associated with a quick phase-out and the maintenance of wholesale electricity prices at acceptable level.

However, such deliberations based on the modelling results may be further complicated by the current state of the Romanian energy system. The modelling has shown, that the current capacity, with some investment, is sufficient to satisfy demand even if lignite power plants are retired early. However, due to the poor state of power plants, not all capacities included in the model are currently operational. Further evidence is available from Transelectrica, the Romanian TSO, end ENTSO-E on the impact of coal power plant closure on **system adequacy**.

A recent adequacy report from Transelectrica shows that domestic generation capacities are not sufficient without coal under very severe weather conditions and peak demand in the coming years. (Transelectrica, December 2019) The Transelectrica adequacy report constructed a scenario assuming the unavailability of more than 12000 MW capacity in peak winter within the period 2022-2027, where most PV, wind and hydro capacity together with high share of coal and lignite plants become unavailable. Shortages in gas network supply are also assumed in the scenario resulting in two thirds of installed capacities becoming unavailable, and 1799 and 2512 MW missing capacity in the Romanian system in 2022 and 2027, respectively. Given the net transfer capacity of 2000 MW, even such severe power plant failure should not cause system adequacy issues in 2022, while by 2027 investment in additional generation capacities (mainly natural gas) is foreseen, as well as newly built NTC capacity additions are in the range of additional 1000 MW from Hungary and Serbia. This implies that although generation adequacy may be insufficient, system adequacy (which considers not only domestic generation but also net transfer capacity) is sufficient even in the absence of coal plants and other restrictive conditions.

The latest ENTSO-E Mid-term adequacy report (2019) assessed a reference as well as a Low-carbon sensitivity scenario for Romania, assuming a 3.7 GW of lignite and coal capacity phase-out by 2025. In the Reference scenario there are no EENS neither LOLE (Loss of load expectation) problems detected, while in the Low-carbon sensitivity case (including the phase-out) LOLE reached 0.04 h/year and EENS 0.01 GWh/year values. According to the ENTSO-E benchmarks a LOLE under a value of 3 h/year shows insignificant security of supply issues. This reinforces our results that Romania does not face realistic security of supply problems even if a phase-out scenario is considered. The

[10] for more detials see: https://rekk.hu/downloads/projects/SEERMAP_CR_ROMANIA_A4_ONLINE.pdf

ENTSO-E and our assessments find that investments in new generation capacities, either gas or RES based, and in higher interconnection levels would be the most adequate way to further increase the robustness of the Romanian electricity system. The 943/2019 EU Regulation to be implemented from this year requires the increase of NTCs to 70% of the physical potential, which would further strengthen the interconnection capacity in the region.

There is a need for additional **capacity investment** to replace some of the coal and lignite power plants. The choices of how such investments will be made need to be carefully considered, based on their respective costs, benefits and risks. Because of the need to install new power generation capacity as quickly as possible, the current plans in Romania consist of new CCGT projects at both the Oltenia Energy Complex and the Hunedoara Energy Complex. Additionally, Romgaz, another state-owned company, is making progress with the construction of a 430MW CCGT facility, due in 2020, while Rompetrol is working on a smaller scale 73MW cogeneration gas unit. In total, one is likely to see at least 1,600MW of new gas-fired power generation in Romania by 2026.

While the installation of all these new **CCGT** units would cover much of the country's capacity deficit, it also comes with some risks, such as the need for additional gas supply. The current trend of domestic natural gas production is a 4-5% yearly decrease. Recent legislative measures have also delayed indefinitely the commencement of extraction of natural gas from the largest offshore deep-water find in the Black Sea. Consequently, an increased consumption of natural gas in the following years would need to be met through growing imports. The combination of the resulting gas price exposure caused by greater reliance on imports, the expected increases in gas prices as well as EUA prices will likely negatively impact the profitability of those planned CCGT units, with a risk for them to become stranded assets.

Another risk that must be taken into account is the potential crowding out effect that such investments, alongside possible investments in additional **nuclear** power generation, may cause for RES projects. The new CCGT investments are supposed to be partially financed through the Modernisation Fund, with the rest of financing likely to be secured by the majority stakeholder, the Energy Ministry – currently part of the newly minted Ministry of Economy, Energy and Business Environment. Meanwhile, as a matter of stated governmental policy, the planned two new nuclear reactors are to benefit from contracts for difference (CfDs). The authorities must ensure that these measures will not significantly reduce the regulatory incentives and financing sources for simultaneous RES investments. Such concerns are grounded in the fact that, as indicated in the draft NECP, the applicability of CfDs for renewables would be postponed until 2025. The Government must refrain from hindering the installation of new RES capacity, which is likely to decrease the wholesale electricity prices and, implicitly, the profitability of the CCGT units.

When it comes to new **RES investment**, the modelling conducted for this project provides a number of crucial insights about the implications of different RES scenarios. A strong deployment of renewables as proclaimed in the reference (Ref RES) scenario shows decreased profitability of coal- and lignite power plants until 2030, though not dramatically, while providing more system-level welfare – the more so the more ambitious the coal phase-out scenario. By 2025, both profits and utilization rates of lignite and coal PPs are very low in the Ref RES scenario, with utilization rates under 16%.

As a simple power market principle, a higher RES penetration will "move" the merit order's limit to the left of the price axis, affecting the profits of coal-fired PPs, both in terms of prices (as the closing price will decrease) and traded volumes (since coal generators will need to meet a lower demand). Compared with Bulgaria and Greece, the utilization rates of lignite-fired PPs in 2025 are the lowest in Romania, by far, even in the most ambitious retirement scenario. The modelling results also show that high RES scenarios diminish wholesale prices.

Based on the types and designs of support mechanisms, this effect can be amplified. For example, as PPAs for renewables will become available in Romania and contracts will be closed outside the centralized electricity market, the volumes traded on spot markets (Day Ahead and Intra-Day) and Balancing Market will decrease. The effect of high RES integration is even more visible in the Sensitivity Analysis done for Romania based on a more realistic projection of the total electricity demand in Romania in 2030 (see above).

This study also provides estimations for the investments needed to increase the penetration of RES. The Green-X model shows that the average yearly investment in new RES in Romania, in the Ref RES scenarios, varies between EUR 826 million and EUR 871 million, which is considerable, yet not unprecedented, bearing in mind that in the golden years of the Romanian RES boom (2011-2015), the yearly RES investment exceeded EUR 1.5 billion. More than EUR 8 billion were invested in wind and solar PV power in Romania. The difference, however, is that that investment boom took place on the back of a generous RES support scheme, which currently is no longer available. Nonetheless, given the steep decrease in technological costs, more efficient generation assets are now available for about half the LCOE level.

There are clear costs and benefits associated with each scenario which need to be weighed. Significantly increasing investment in RES capacity would require a more favourable regulatory environment, in order to incentivize potential RES investors with the following, among other things: the possibility of closing PPAs (currently precluded under Romanian legislation), the existence of a support mechanism, such as the introduction of competitive CfDs for RES and storage capacities, as well as other regulatory improvements regarding the merit order and the balancing market. Certainly, the higher national RES target for 2030 (most probably 30.5% in the final NECP paper) and the provisions of the Regulation on the internal electricity market EU 2019/943 (which reinstate the possibility of closing PPAs) will most likely catalyse the needed adjustments – at least in good part.

Such policy measures aimed at creating a more favourable environment for RES, next to the planned investment in new gas plants, represent pillars of the measures that the Romanian authorities need to take in order to phase-out coal while simultaneously ensuring security of supply and acceptable wholesale electricity prices.

Meanwhile, attention must be paid to **improved interconnections, transmission and distribution lines**, Demand Side Management, storage and sector coupling technologies, along with a proper market design. Such measures are not only complementary to the aforementioned solutions, but also necessary for limiting the negative financial effects of both the losses of the coal sector and the support scheme needed to maintain its activity, while providing future-proof answers to system adequacy issues. Given the complexity of such measures, they can only be achieved through an integrated and comprehensive strategy for coal phase-out in Romania.

The study’s main conclusion for Romania is that, in order to offer visibility and predictability to the coal phase-out process and its implications on the energy system and economy as a whole, Romania must develop and implement a coal **phase--out strategy**. The strategy should include a calendar for shutting down mines and retiring coal-fired PPs, as well as for the new replacement capacities and other required measures for supporting this transformation of the energy system.

At the same time, the strategy must include a clear and realistic plan on dealing with the **direct and indirect loss and de-localization of jobs, as well as the economic impact** at local and national level. Very importantly, the added value of the strategy should consist in identifying solutions and measures for a Just Transition, as well as to propose viable financing options for each issue. This would ensure that all trade-offs covered in this report have been adequately considered, and give the Government the means to increase public acceptability of the coal phase-out by providing guarantees and predictability.

A robust coal phase-out strategy should also be a precondition for the approval of any state aid measures for coal power plants and should determine the size and duration of such a measure. Given the results of this study, the decision-makers ought to plan for the speediest closure of lignite- and hard coal-fired power plants as soon as system adequacy is ensured, while also facilitating strong RES investments.

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Annex 1 – Modelling methodology and assumptions

Modelling methodology

The modelling aims to respond to a number of policy relevant questions related to an early coal and lignite phase-out. The models used are the European Electricity Market Model (EEMM) and European Power Market Model (EPMM) both developed by the Regional Centre for Energy Policy Research (REKK) and the Green-X model of the Energy Economics Group at Technische Universität Wien (EEG TU Wien).

The project follows on previous modelling work that has been carried out with the use of these two models (EEMM and Green-X) in the South East Europe region. The SEERMAP project (Szabó et al., 2017) has shown that a high RES share leading to 94% decarbonisation of the electricity sector is technically and economically feasible in the SEE region and can be implemented without compromising system security. The aim of the current modelling exercise, using the same models, but running different scenarios with an updated set of assumptions, is to show the impact of an early phase-out of lignite in terms of power plant profitability and utilization rates, system security, electricity wholesale price and RES support levels.

Model description

Two main models were used for modelling the impact of an early phase-out of coal and lignite, the European Electricity Market Model (EEMM) and the Green-X model. In addition, the European Gas Market Model (EGMM) was used to project the future price of natural gas and the European Power Market Model (EPMM) model was used to assess system security of the modelled scenarios.

The EEMM is a Europe-wide electricity sector model covering 41 markets of 38 countries and around 3400 power plant units. The covered countries include all EU member states, the Western Balkans, and countries bordering the EU. Power flow is ensured by more than 100 interconnectors between the markets, where each market is treated as a single node. The EEMM model has an hourly time step and models 90 representative hours of the year. These representative hours have been selected taking into account changes in daily and seasonal load to ensure these hours represent both peak and base load hours, and that the impact of volatility in the generation of intermittent RES technologies on wholesale price levels is captured.

Demand is fed into the EEMM model exogenously by the modellers, and the model then satisfies this demand in a welfare optimising way (the outcome generates the maximum consumer surplus and minimum cost of production), taking into account constraints in both domestic generation capacity and cross-border capacity limits. The model assumes a competitive allocation of both production capacities and cross-border capacities. The merit order curve of the supply side is built up for each country based on the marginal costs of production units, then prices are derived from the demand-supply balance also taking into account import (and export) possibilities. Due to increasing demand for electricity and retirement of existing power plants, in order to satisfy demand, the model may need to include new fossil fuelled power plants. When deciding which new capacities to build to satisfy demand, the model chooses the technology which is most profitable estimated based on a 10-year-projection. The model is conservative with respect to technological developments and thus no significant technological breakthrough is assumed (e.g. battery storage, fusion, etc.), although CCS has been included as an investment possibility.

EEMM lacks a detailed representation of renewable energy and was therefore linked to the Green-X model. Green-X is an energy system model, developed and operated by TU Wien, that offers a detailed representation of RES potentials and related technologies in Europe and in neighbouring countries. It aims at indicating consequences of RES policy choices in a real-world energy policy context thanks to its comprehensive incorporation of various energy policy instruments including related design features. The model simulates technology-specific RES deployment by country on a yearly basis, in the time span up to 2050, taking into account the impact of dedicated support schemes as well as economic and non-economic framework conditions (e.g. regulatory and societal constraints). Moreover, the model allows for an appropriate representation of financing conditions and of the related impact on investment risk. This, in turn, allows conducting in-depth analyses of future RES deployment and corresponding costs, expenditures and benefits arising from the preconditioned policy choices on country, sector and technology level.

Additional modelling with EPMM was carried out to test whether the scenarios developed using the EEMM and Green-X models cause system balancing issues. The EPMM model has the same geographic coverage as the EEMM but has a more detailed representation of the variation in load and availability, as it models 8760 hours of the year instead of 90 representative hours. The EPMM is a unit commitment model which simultaneously optimizes all 168 hours of a week and determines the production level of each modelled power plant unit. One model run covers all 52 weeks of a year. When calculating system costs both start-up and shut-down costs of the power plants, the marginal cost of production (mostly fuel and CO_2 costs) and the costs that occur in case of RES curtailment are taken into account. The missing production levels, RES curtailments (if any) and the available upward and downward reserve capacities are important outputs of the model, through which level of security of supply and system adequacy can be measured.

Modelling approach

The modelling consists of the interaction of four models, in the following way:

- As a first step, natural gas price trajectories were determined by using EGMM. RES capacity deployment levels were determined by the Green-X model, based on the latest NECP information available.
- As a next step, natural gas prices, the renewable penetration data and all other relevant inputs from partners (e.g. on fuel use, fuel costs, variable costs) are input into EEMM to calculate the equilibrium electricity market wholesale price levels, the electricity trade between countries, and the utilisation rates and profit levels of power plants under the different scenarios (see Annex 1). In addition, market values (production pattern

weighted wholesale prices) for different renewable technologies are quantified. The model also decides on possible investments in new natural gas and coal fired power plants, based on their economic return.

- Taking into account the new (modelled and exogenously determined) natural gas-based capacity investments, the resulting power system of the three countries is analysed from a system flexibility point of view with the unit commitment model EPMM. Reserve adequacy, energy not supplied (ENS) and RES curtailment indicators are calculated using the model.
- Using the market values from EEMM, the Green-X model determines the required support for renewables country by country for all scenarios.

Due to the way the models were linked, with RES capacities determined exogenously in the EEMM model, the modelling approach is not suited for determining the optimal capacity mix between renewables and gas to replace coal and lignite. Irrespective of the timing of coal phase-out the capacities of RES are the same in all scenarios.

Model assumptions

All scenarios share common framework assumptions to ensure their comparability with respect to the impact of the timing of coal and lignite capacity retirement. The common assumptions across all scenarios are presented below. Detailed information on assumptions is contained in Annex 2.

Projected electricity demand is based on data from official national strategies. These show annual electricity demand growth rates of 1.1%, close to 0% and 2.9% in Bulgaria, Greece and Romania, respectively. Sensitivity analysis for demand was performed where demand figures were taken from the European Commission's impact assessment for the 2030 targets; demand data from the scenario consistent with a 32% renewables share and 32.5% energy efficiency improvement was used for the sensitivity analysis.

Fossil fuel prices were taken from different sources. The price of coal was based on ARA futures prices. It was assumed that following an initial decrease in the price of coal by 21% by 2020 compared with 2019 levels, the price of coal would remain stable between 2020 and 2030. Lignite prices were received from partners for each power plant. Natural gas prices were modelled using the European Gas Market Model (EGMM) of REKK. The results show that while the gas price will increase by 6% by 2030 compared with current levels in Greece, the price increase in Bulgaria and Romania over the same period will be around 3%.

Investment in generation capacity can happen in two ways in the model. Investments planned in official national documents were included exogenously. Therefore, in total 770 MW new coal or lignite capacity, 1700 MW new nuclear and 3868 MW new natural gas capacity was assumed to come online in the three modelled countries by 2030. In addition, the model was allowed to invest in further generation capacity if it seems to be profitable based on 10-year-ahead modelling results. However, as the planned investment is already significant, and given the RES capacity (also exogenous in the model), there was no further need for investment in generation capacity in the modelled scenarios. The fact that all new fossil, nuclear and RES capacities were exogenous in the electricity market model allows for only limited conclusions to be drawn with respect to the cost-optimal energy mix to replace retiring coal and lignite plants.

Two sources were used for investment costs of different technologies. Information on actual costs was used for known planned investment, while benchmark information was used for endogenous power plant investment. The latter investment cost data for new generation technologies was taken from EIA (2018).

Weighted average cost of capital (WACC) was assumed to be in the range of 9.6% to 11.4% for investments in new RES power generation facilities in the forthcoming decade (post 2020), with a small differentiation across technologies and countries that reflects the current risk perceptions.

The EU ETS allowance price was assumed to increase from 15 EUR/tCO_2 in 2018 to 35 EUR/tCO_2 in 2021, and then remaining relatively stable, with prices between 35-38 EUR/MWh until 2030 in the medium level CO_2 price scenario. Sensitivity analysis was performed using 50% lower and higher prices in the low CO_2 price and high CO_2 price sensitivity analyses, respectively.

Data on cross-border transmission capacities for 2018 was available from ENTSO-E with future NTC values based on the ENTSO-E TYNDP 2018. New and existing gas infrastructure is included based on data from ENTSO-G TYNDP 2018 and GIIGNL both on pipelines and LNG terminals. For the former both expansions and new projects are included, while no new LNG terminal was assumed for the three modelled countries.

Methodology for calculating regional funding needs for a just transition

In order to evaluate the funding needs associated with a coal-phase out in Bulgaria, Greece and Romania, four main funding categories were identified:

1) Investment needed to compensate for direct job losses;
2) Investment needed to compensate for indirect jobs losses;
3) Investment required to offset GVA losses;
4) Compensation for municipal taxes.

This calculation did not differentiate between different scenarios and the timing of the phase-out, but assumed that the losses would occur whenever phase-out occurs. This section presents the methodology used to estimate funding needs, data used and data sources.

Offsetting the negative direct employment impact

As a first step, data was collected regarding the number of employees in power plants and in mines, by two age categories: younger than 55, and 55 or older. It was assumed that due to the coal and lignite phase-out all jobs in the sector would be lost.

In order to calculate the cost of a just transition, it was assumed that workers would either go into early retirement, or require re-skilling, job-matching or business start-up aid. Four corresponding cost categories were identified in thousand EUR/capita as shown in Table 11. Specific National data were not available and instead regional cost benchmark data were used.

Table 11 Cost of just transition per worker, thousand EUR/capita

	Bulgaria	Greece	Romania
Re-skilling	8	8	8
Job matching	5	4	5
Business start-up aid	15	15	15
Early retirement	36	78	36

Source: regional partners

National experts estimated the number of employees affected by each of the four support schemes. It was assumed that some beneficiaries would require more than one form of aid. It was also assumed that employees who are 55 or older would be retired early and the remaining workforce would need to find employment in other sectors. The large differences in the cost of early retirement per worker between Greece and the other two countries is due to the differences in pensions, with much higher pensions in Greece.

Offsetting the negative indirect employment impact

No statistical data were available regarding the number of impacted indirect jobs, a multiplier of 2.5 was applied to the number of direct jobs. This is based on estimates from local and is a generous estimate compared with other available sources.

Table 12 Estimate of number of jobs and job multipliers from external sources

	Direct jobs	Indirect intraregional jobs	Indirect interregional jobs	Multiplier (Direct/Indirect) EURACOAL estimate	Multiplier (Direct/Indirect) JRC I-O methodology
Bulgaria	14500	9452	15220	3.9	1.70
Greece	6500	1843	4166	0.5	0.92

Romania	18600	6194	10101	n.a.	0.88

Source: Alves Dias et al., 2018

The number of indirect losses estimated in the project is presented in Table 13.

Table 13 Number of indirect job losses in Bulgaria, Greece and Romania estimated for the current project

Country	number of indirect jobs	total cost [thousand EUR]
Bulgaria	29 120	140 560
Greece	7 010	1 295 300
Romania	19 332	108 743

The methodology for calculating funding needs associated with the transition was the same as for direct job losses.

Investment to offset GVA losses

The volume of the economic impact of the coal phase-out was estimated for both the coal sector and for secondary impacts in other sectors. Due to lack of data, the estimate relied on local expert knowledge regarding the interlinkages between the coal sector and other sectors. In order to compensate for these losses, it is assumed that government investment is needed in the region, to increase economic output of non-coal sectors. The general government capital multiplier, showing the impact of 1 EUR investment on GDP in EUR, was assumed to be 0.8. In terms of the 10-year impact of government investment, this is considered to be a conservative estimate, as generally higher values have been reported for the EU (de Jong, Ferdinandusse, Funda, & Vetlov, 2017), and allows for efficiency losses in spending due to lower institutional capacity.

Country experts also identified which sectors could counterbalance economic losses based on the weight within the local economy and growth rates of individual

Compensation for lost municipal taxes

As a last step, the cost of compensating municipalities for lost tax revenue was calculated. Since the data availability varies significantly among the three countries, no unified methodology was used. In case of Bulgaria, data were not available, therefore regional benchmark data were used to calculate the current tax paid by the different coal companies to the municipalities. In case of Greece, it was identified that municipalities will not be receiving the so-called lignite levy any more starting from this year. And finally, in case of Romania, company-level data were available.

This estimate was not added to the total losses, as it is expected that government expenditure aimed at increasing the economic performance of non-coal sectors would enable municipalities to recover these costs from other sectors. Over the short to medium term, however, municipal revenue losses may be relevant.

Annex 2 - Modelling results

Table 14: Modelling results for Bulgaria, Reference RES, Reference CO2 price

BG REF RES, REF CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 946	3 946	3 946	3 946	3 946	3 969	3 969	3 969	3 969	3 969	3 978	3 978	3 978	3 978	3 978
	PV	1 490	1 490	1 490	1 490	1 490	2 348	2 348	2 348	2 348	2 348	2 959	2 959	2 959	2 959	2 959
	Wind	698	698	698	698	698	699	699	699	699	699	295	295	295	295	295
	Biomass and other RES	139	139	139	139	139	292	292	292	292	292	485	485	485	485	485
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 691	14 691	14 691	14 691	14 691
	Coal and lignite	21 601	21 601	21 601	21 601	21 601	9 961	9 961	2 402	2 402	2 402	2 319	2 319	2 319	2 319	2 319
	Natural gas	1 429	1 429	1 429	1 429	1 429	1 569	1 638	4 145	4 145	4 145	3 141	3 144	3 148	3 152	3 152
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 043	4 043	4 043	4 043	4 043	4 106	4 106	4 106	4 106	4 106	4 153	4 153	4 153	4 153	4 153
	PV	1 899	1 899	1 899	1 899	1 899	2 991	2 991	2 991	2 991	2 991	3 770	3 770	3 770	3 770	3 770
	Wind	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	458	458	458	458	458
	Biomass and other RES	462	462	462	462	462	1 074	1 074	1 074	1 074	1 074	2 023	2 023	2 023	2 023	2 023
	Total	45 904	45 904	45 904	45 904	45 904	36 172	36 240	31 188	31 188	31 188	31 215	31 219	31 222	31 226	31 226

Gross consumption, GWh		38 295	38 295	38 295	38 295	38 295	40 109	40 107	39 963	39 959	39 955	41 446	41 444	41 443	41 442	41 442
Net import, GWh	GR	-4 362	-4 362	-4 362	-4 362	-4 362	-175	-246	2 968	2 966	2 978	6 053	6 083	6 115	6 090	6 090
	MK	-1 662	-1 662	-1 662	-1 662	-1 662	353	354	757	746	735	204	227	230	238	238
	RO	-2 213	-2 213	-2 213	-2 213	-2 213	763	741	1 579	1 579	1 557	1 214	1 178	1 133	1 165	1 165
	RS	-1 939	-1 939	-1 939	-1 939	-1 939	511	532	964	973	989	473	450	457	436	436
	TR	2 567	2 567	2 567	2 567	2 567	2 487	2 487	2 507	2 507	2 507	2 287	2 287	2 287	2 287	2 287
	Total	-7 609	-7 609	-7 609	-7 609	-7 609	3 938	3 867	8 775	8 771	8 766	10 231	10 225	10 221	10 215	10 215
Net import ratio, %		-20%	-20%	-20%	-20%	-20%	10%	10%	22%	22%	22%	25%	25%	25%	25%	25%
Utilisation rates, %	Coal and lignite	55%	55%	55%	55%	55%	57%	57%	65%	65%	65%	63%	63%	63%	63%	63%
	Natural gas	15%	15%	15%	15%	15%	11%	12%	30%	30%	30%	23%	23%	23%	23%	23%
Baseload price, €/MWh		58.31	58.31	58.31	58.31	58.31	66.17	66.32	77.71	78.00	78.34	73.52	73.70	73.73	73.87	73.87
Additional RES support (€/MWh)							0.95				0.59	1.54				1.46
CO_2 emission (kt)		22 887	22 887	22 887	22 887	22 887	11 003	11 036	4 564	4 564	4 564	4 003	4 005	4 007	4 009	4 009

Table 15: Modelling results for Greece, Reference RES, Reference CO2 price

GR REF RES, REF CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 189	4 189	4 189	4 189	4 189	4 890	4 890	4 890	4 890	4 890
	PV	4 593	4 593	4 593	4 593	4 593	6 546	6 546	6 546	6 546	6 546	8 976	8 976	8 976	8 976	8 976
	Wind	3 024	3 024	3 024	3 024	3 024	4 153	4 153	4 153	4 153	4 153	5 390	5 390	5 390	5 390	5 390
	Biomass and other RES	94	94	94	94	94	235	235	235	235	235	302	302	302	302	302
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	5 139	5 139	5 139	5 139	5 139	3 034	3 108	2 651	2 651	2 651	2 402	2 402	2 403	2 403	2 403
	Natural gas	22 554	22 554	22 554	22 554	22 554	24 459	24 474	25 772	25 772	25 772	22 794	22 795	22 796	22 797	22 797
	HFO/LFO	27	27	27	27	27	20	20	278	278	278	71	71	71	71	71
	Hydro	5 136	5 136	5 136	5 136	5 136	5 260	5 260	5 260	5 260	5 260	6 112	6 112	6 112	6 112	6 112
	PV	6 618	6 618	6 618	6 618	6 618	9 431	9 431	9 431	9 431	9 431	12 879	12 879	12 879	12 879	12 879
	Wind	5 308	5 308	5 308	5 308	5 308	7 291	7 291	7 291	7 291	7 291	9 449	9 449	9 449	9 449	9 449
	Biomass and other RES	451	451	451	451	451	1 131	1 131	1 131	1 131	1 131	1 454	1 454	1 454	1 454	1 454
	Total	45 234	45 234	45 234	45 234	45 234	50 626	50 717	51 814	51 814	51 814	55 161	55 161	55 163	55 164	55 164
Gross consumption, GWh		57 639	57 639	57 639	57 639	57 639	57 668	57 665	57 462	57 457	57 451	58 260	58 257	58 257	58 255	58 255
Net import, GWh	AL	1 713	1 713	1 713	1 713	1 713	1 491	1 419	1 802	1 795	1 801	1 127	1 115	1 151	1 155	1 155
	BG	4 362	4 362	4 362	4 362	4 362	175	246	-2 968	-2 966	-2 978	-6 053	-6 083	-6 115	-6 090	-6 090
	IT	3 374	3 374	3 374	3 374	3 374	2 536	2 536	3 710	3 710	3 710	2 990	3 013	3 036	3 028	3 028

	MK	1 783	1 783	1 783	1 783	1 783	1 724	1 631	1 996	1 996	1 996	4 017	4 032	4 002	3 978	3 978
	TR	1 174	1 174	1 174	1 174	1 174	1 116	1 116	1 109	1 109	1 109	1 019	1 019	1 019	1 019	1 019
	Total	12 405	12 405	12 405	12 405	12 405	7 042	6 949	5 649	5 643	5 637	3 100	3 096	3 094	3 090	3 090
Net import ratio, %		22%	22%	22%	22%	22%	12%	12%	10%	10%	10%	5%	5%	5%	5%	5%
Utilisation rates, %	Coal and lignite	21%	21%	21%	21%	21%	12%	12%	46%	46%	46%	42%	42%	42%	42%	42%
	Natural gas	46%	46%	46%	46%	46%	44%	44%	46%	46%	46%	42%	42%	42%	42%	42%
Baseload price, €/MWh		65.68	65.68	65.68	65.68	65.68	66.17	66.32	77.68	77.97	78.31	72.65	72.82	72.85	72.99	72.99
Additional RES support (€/MWh)							1.44				0.86	2.00				1.92
CO_2 emission (kt)		14 280	14 280	14 280	14 280	14 280	12 236	12 328	12 424	12 424	12 424	10 895	10 895	10 896	10 897	10 897

Table 16: Modelling results for Romania, Reference RES, Reference CO2 price

RO REF RES, REF CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 589	7 589	7 589	7 589	7 589	8 168	8 168	8 168	8 168	8 168
	PV	1 499	1 499	1 499	1 499	1 499	1 669	1 669	1 669	1 669	1 669	1 910	1 910	1 910	1 910	1 910
	Wind	4 403	4 403	4 403	4 403	4 403	5 535	5 535	5 535	5 535	5 535	6 814	6 814	6 814	6 814	6 814
	Biomass and other RES	250	250	250	250	250	823	823	823	823	823	1 237	1 237	1 237	1 237	1 237
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 893	15 893	15 893	15 893	15 893
	Coal and lignite	3 155	3 155	3 155	3 155	3 155	872	398	522	439	340	617	422	256	0	0
	Natural gas	10 436	10 436	10 436	10 436	10 436	18 809	18 814	18 873	18 877	18 879	17 399	17 399	17 399	17 399	17 399
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 528	19 528	19 528	19 528	19 528	21 131	21 131	21 131	21 131	21 131
	PV	1 664	1 664	1 664	1 664	1 664	1 852	1 852	1 852	1 852	1 852	2 119	2 119	2 119	2 119	2 119
	Wind	10 042	10 042	10 042	10 042	10 042	12 622	12 622	12 622	12 622	12 622	15 539	15 539	15 539	15 539	15 539
	Biomass and other RES	552	552	552	552	552	2 235	2 235	2 235	2 235	2 235	3 372	3 372	3 372	3 372	3 372
	Total	54 274	54 274	54 274	54 274	54 274	66 550	66 081	66 263	66 185	66 088	76 070	75 875	75 708	75 453	75 453
Gross consumption, GWh		56 808	56 808	56 808	56 808	56 808	68 199	68 196	68 139	68 118	68 094	79 903	79 897	79 892	79 852	79 852
Net import, GWh	BG	2 213	2 213	2 213	2 213	2 213	-763	-741	-1 579	-1 579	-1 557	-1 214	-1 178	-1 133	-1 165	-1 165
	HU	-493	-493	-493	-493	-493	-2 509	-2 289	-1 721	-1 721	-1 704	825	869	936	1 029	1 029
	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	RS	-799	-799	-799	-799	-799	4 733	4 922	4 840	4 885	4 903	4 159	4 342	4 456	4 581	4 581
	UA	1 613	1 613	1 613	1 613	1 613	188	224	336	348	365	63	-11	-76	-46	-46
	Total	2 534	2 534	2 534	2 534	2 534	1 649	2 115	1 876	1 934	2 007	3 833	4 022	4 184	4 399	4 399
Net import ratio, %		4%	4%	4%	4%	4%	2%	3%	3%	3%	3%	5%	5%	5%	6%	6%
Utilisation rates, %	Coal and lignite	10%	10%	10%	10%	10%	4%	2%	4%	5%	5%	5%	6%	4%	-	-
	Natural gas	41%	41%	41%	41%	41%	69%	69%	70%	70%	70%	59%	59%	59%	59%	59%
Baseload price, €/MWh		60.19	60.19	60.19	60.19	60.19	65.37	65.54	68.21	69.17	70.31	66.55	66.84	67.02	68.70	68.70
Additional RES support (€/MWh)							2.95				2.65	6.65				6.40
CO_2 emission (kt)		7 472	7 472	7 472	7 472	7 472	7 985	7 368	7 550	7 451	7 336	7 018	6 784	6 624	6 312	6 312

Table 17: Modelling results for Bulgaria, Reference RES, High CO2 price

BG REF RES, High CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 946	3 946	3 946	3 946	3 946	3 969	3 969	3 969	3 969	3 969	3 978	3 978	3 978	3 978	3 978
	PV	1 490	1 490	1 490	1 490	1 490	2 348	2 348	2 348	2 348	2 348	2 959	2 959	2 959	2 959	2 959
	Wind	698	698	698	698	698	699	699	699	699	699	295	295	295	295	295
	Biomass and other RES	139	139	139	139	139	292	292	292	292	292	485	485	485	485	485
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 691	14 691	14 691	14 691	14 691
	Coal and lignite	17 197	17 197	17 197	17 197	17 197	7 239	7 239	2 188	2 188	2 188	2 046	2 046	2 046	2 046	2 046
	Natural gas	1 672	1 672	1 672	1 672	1 672	2 164	2 164	4 068	4 068	4 068	2 800	2 800	2 800	2 800	2 800
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 043	4 043	4 043	4 043	4 043	4 106	4 106	4 106	4 106	4 106	4 153	4 153	4 153	4 153	4 153
	PV	1 899	1 899	1 899	1 899	1 899	2 991	2 991	2 991	2 991	2 991	3 770	3 770	3 770	3 770	3 770
	Wind	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	458	458	458	458	458
	Biomass and other RES	462	462	462	462	462	1 074	1 074	1 074	1 074	1 074	2 023	2 023	2 023	2 023	2 023
	Total	41 743	41 743	41 743	41 743	41 743	34 045	34 045	30 898	30 898	30 898	30 601	30 601	30 601	30 601	30 601
Gross consumption, GWh		38 154	38 154	38 154	38 154	38 154	39 992	39 992	39 869	39 865	39 861	41 344	41 345	41 344	41 343	41 343
Net import, GWh	GR	-3 610	-3 610	-3 610	-3 610	-3 610	1 624	1 655	3 645	3 647	3 655	6 688	6 688	6 695	6 694	6 694
	MK	-696	-696	-696	-696	-696	416	418	639	639	638	466	466	453	453	453
	RO	-845	-845	-845	-845	-845	976	952	1 506	1 500	1 489	999	1 000	1 004	1 004	1 004

	RS	-1 066	-1 066	-1 066	-1 066	-1 066	418	410	641	641	641	269	269	270	270	270
	TR	2 628	2 628	2 628	2 628	2 628	2 513	2 513	2 540	2 540	2 540	2 321	2 321	2 321	2 321	2 321
	Total	-3 589	-3 589	-3 589	-3 589	-3 589	5 948	5 948	8 971	8 967	8 963	10 743	10 744	10 743	10 742	10 742
Net import ratio, %		-9%	-9%	-9%	-9%	-9%	15%	15%	23%	22%	22%	26%	26%	26%	26%	26%
Utilisation rates, %	Coal and lignite	44%	44%	44%	44%	44%	41%	41%	59%	59%	59%	55%	55%	55%	55%	55%
	Natural gas	18%	18%	18%	18%	18%	16%	16%	29%	29%	29%	20%	20%	20%	20%	20%
Baseload price, €/MWh		71.10	71.10	71.10	71.10	71.10	76.17	76.17	85.80	86.09	86.42	82.04	81.97	82.00	82.13	82.13
Additional RES support (€/MWh)							0.48				0.17	0.84				0.54
CO_2 emission (kt)		18 367	18 367	18 367	18 367	18 367	8 543	8 543	4 329	4 329	4 329	3 583	3 583	3 583	3 583	3 583

Table 18: Modelling results for Greece, Reference RES, High CO2 price

GR REF RES, High CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 189	4 189	4 189	4 189	4 189	4 890	4 890	4 890	4 890	4 890
	PV	4 593	4 593	4 593	4 593	4 593	6 546	6 546	6 546	6 546	6 546	8 976	8 976	8 976	8 976	8 976
	Wind	3 024	3 024	3 024	3 024	3 024	4 153	4 153	4 153	4 153	4 153	5 390	5 390	5 390	5 390	5 390
	Biomass and other RES	94	94	94	94	94	235	235	235	235	235	302	302	302	302	302
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	3 775	3 775	3 775	3 775	3 775	2 034	2 112	2 591	2 591	2 591	2 232	2 232	2 235	2 235	2 235
	Natural gas	24 520	24 520	24 520	24 520	24 520	26 202	26 202	26 659	26 659	26 659	24 526	24 526	24 527	24 527	24 527
	HFO/LFO	21	21	21	21	21	19	14	264	264	264	68	68	68	68	68
	Hydro	5 136	5 136	5 136	5 136	5 136	5 260	5 260	5 260	5 260	5 260	6 112	6 112	6 112	6 112	6 112
	PV	6 618	6 618	6 618	6 618	6 618	9 431	9 431	9 431	9 431	9 431	12 879	12 879	12 879	12 879	12 879
	Wind	5 308	5 308	5 308	5 308	5 308	7 291	7 291	7 291	7 291	7 291	9 449	9 449	9 449	9 449	9 449
	Biomass and other RES	451	451	451	451	451	1 131	1 131	1 131	1 131	1 131	1 454	1 454	1 454	1 454	1 454
	Total	45 830	45 830	45 830	45 830	45 830	51 370	51 442	52 627	52 627	52 627	56 719	56 719	56 724	56 724	56 724
Gross consumption, GWh		57 422	57 422	57 422	57 422	57 422	57 503	57 502	57 332	57 327	57 321	58 117	58 118	58 118	58 116	58 116
Net import, GWh	AL	1 339	1 339	1 339	1 339	1 339	1 405	1 371	1 646	1 643	1 645	679	679	642	643	643
	BG	3 610	3 610	3 610	3 610	3 610	-1 624	-1 655	-3 645	-3 647	-3 655	-6 688	-6 688	-6 695	-6 694	-6 694

	IT	4 066	4 066	4 066	4 066	4 066	3 695	3 674	3 825	3 825	3 825	3 148	3 148	3 155	3 155	3 155
	MK	1 403	1 403	1 403	1 403	1 403	1 533	1 547	1 774	1 774	1 774	3 249	3 249	3 282	3 278	3 278
	TR	1 174	1 174	1 174	1 174	1 174	1 123	1 123	1 104	1 104	1 104	1 010	1 010	1 010	1 010	1 010
	Total	11 592	11 592	11 592	11 592	11 592	6 133	6 060	4 704	4 699	4 693	1 398	1 399	1 394	1 392	1 392
Net import ratio, %		20%	20%	20%	20%	20%	11%	11%	8%	8%	8%	2%	2%	2%	2%	2%
Utilisation rates, %	Coal and lignite	15%	15%	15%	15%	15%	8%	8%	45%	45%	45%	39%	39%	39%	39%	39%
	Natural gas	50%	50%	50%	50%	50%	47%	47%	48%	48%	48%	46%	46%	46%	46%	46%
Baseload price, €/MWh		78.73	78.73	78.73	78.73	78.73	76.06	76.07	85.54	85.84	86.17	81.18	81.11	81.14	81.27	81.27
Additional RES support (€/MWh)							0.46				0.33	0.50				0.49
CO_2 emission (kt)		13 573	13 573	13 573	13 573	13 573	11 837	11 922	12 712	12 712	12 712	11 387	11 387	11 391	11 391	11 391

Table 19: Modelling results for Romania, Reference RES, High CO2 price

RO REF RES, High CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 589	7 589	7 589	7 589	7 589	8 168	8 168	8 168	8 168	8 168
	PV	1 499	1 499	1 499	1 499	1 499	1 669	1 669	1 669	1 669	1 669	1 910	1 910	1 910	1 910	1 910
	Wind	4 403	4 403	4 403	4 403	4 403	5 535	5 535	5 535	5 535	5 535	6 814	6 814	6 814	6 814	6 814
	Biomass and other RES	250	250	250	250	250	823	823	823	823	823	1 237	1 237	1 237	1 237	1 237
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 893	15 893	15 893	15 893	15 893
	Coal and lignite	1 478	1 478	1 478	1 478	1 478	373	266	434	379	311	219	273	134	0	0
	Natural gas	15 457	15 457	15 457	15 457	15 457	18 903	18 908	18 927	18 927	18 927	21 471	21 471	21 471	21 471	21 471
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 528	19 528	19 528	19 528	19 528	21 131	21 131	21 131	21 131	21 131
	PV	1 664	1 664	1 664	1 664	1 664	1 852	1 852	1 852	1 852	1 852	2 119	2 119	2 119	2 119	2 119
	Wind	10 042	10 042	10 042	10 042	10 042	12 622	12 622	12 622	12 622	12 622	15 539	15 539	15 539	15 539	15 539
	Biomass and other RES	552	552	552	552	552	2 235	2 235	2 235	2 235	2 235	3 372	3 372	3 372	3 372	3 372
	Total	57 619	57 619	57 619	57 619	57 619	66 145	66 043	66 230	66 175	66 107	79 743	79 797	79 659	79 524	79 524
Gross consumption, GWh		56 619	56 619	56 619	56 619	56 619	68 006	68 006	67 955	67 938	67 916	79 666	79 675	79 674	79 640	79 640
Net import, GWh	BG	845	845	845	845	845	-976	-952	-1 506	-1 500	-1 489	-999	-1 000	-1 004	-1 004	-1 004
	HU	-2 123	-2 123	-2 123	-2 123	-2 123	-3 236	-3 221	-2 599	-2 600	-2 597	-550	-576	-527	-506	-506

	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	RS	-1 211	-1 211	-1 211	-1 211	-1 211	6 034	6 093	5 787	5 819	5 852	1 368	1 351	1 429	1 473	1 473
	UA	1 489	1 489	1 489	1 489	1 489	40	43	43	44	43	104	103	118	151	151
	Total	-1 000	-1 000	-1 000	-1 000	-1 000	1 861	1 963	1 725	1 763	1 809	-77	-122	15	115	115
Net import ratio, %		-2%	-2%	-2%	-2%	-2%	3%	3%	3%	3%	3%	0%	0%	0%	0%	0%
Utilisation rates, %	Coal and lignite	5%	5%	5%	5%	5%	2%	1%	3%	4%	5%	2%	4%	2%	-	-
	Natural gas	61%	61%	61%	61%	61%	70%	70%	70%	70%	70%	73%	73%	73%	73%	73%
Baseload price, €/MWh		71.73	71.73	71.73	71.73	71.73	75.14	75.15	77.56	78.35	79.37	76.79	76.41	76.46	77.89	77.89
Additional RES support (€/MWh)							1.91				1.78	4.09				3.96
CO_2 emission (kt)		7 434	7 434	7 434	7 434	7 434	7 397	7 256	7 469	7 402	7 322	8 035	8 103	7 972	7 808	7 808

Table 20: Modelling results for Bulgaria, Reference RES, Low CO2 price

BG REF RES, Low CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 946	3 946	3 946	3 946	3 946	3 969	3 969	3 969	3 969	3 969	3 978	3 978	3 978	3 978	3 978
	PV	1 490	1 490	1 490	1 490	1 490	2 348	2 348	2 348	2 348	2 348	2 959	2 959	2 959	2 959	2 959
	Wind	698	698	698	698	698	699	699	699	699	699	295	295	295	295	295
	Biomass and other RES	139	139	139	139	139	292	292	292	292	292	485	485	485	485	485
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 691	14 691	14 691	14 691	14 691
	Coal and lignite	24 536	24 536	24 536	24 536	24 536	11 247	11 248	2 532	2 532	2 532	2 369	2 369	2 369	2 369	2 369
	Natural gas	1 224	1 224	1 224	1 224	1 224	1 265	1 305	3 960	3 972	3 983	2 962	2 982	2 986	3 009	3 009
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 043	4 043	4 043	4 043	4 043	4 106	4 106	4 106	4 106	4 106	4 153	4 153	4 153	4 153	4 153
	PV	1 899	1 899	1 899	1 899	1 899	2 991	2 991	2 991	2 991	2 991	3 770	3 770	3 770	3 770	3 770
	Wind	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	458	458	458	458	458
	Biomass and other RES	462	462	462	462	462	1 074	1 074	1 074	1 074	1 074	2 023	2 023	2 023	2 023	2 023
	Total	48 634	48 634	48 634	48 634	48 634	37 154	37 194	31 134	31 145	31 157	31 086	31 106	31 109	31 133	31 133
Gross consumption, GWh		38 426	38 426	38 426	38 426	38 426	40 217	40 214	40 040	40 036	40 032	41 527	41 525	41 524	41 522	41 522
Net import, GWh	GR	-4 380	-4 380	-4 380	-4 380	-4 380	-1 875	-1 455	2 177	2 186	2 179	5 403	5 384	5 401	5 421	5 421
	MK	-1 741	-1 741	-1 741	-1 741	-1 741	503	517	771	761	771	618	625	608	568	568
	RO	-2 252	-2 252	-2 252	-2 252	-2 252	1 369	1 080	2 203	2 167	2 147	1 704	1 706	1 601	1 572	1 572
	RS	-2 115	-2 115	-2 115	-2 115	-2 115	619	421	1 298	1 321	1 320	737	724	804	828	828

	TR	280	280	280	280	280	2 446	2 456	2 458	2 458	2 458	1 979	1 979	2 001	2 001	2 001
	Total	-10 208	-10 208	-10 208	-10 208	-10 208	3 063	3 020	8 906	8 891	8 875	10 441	10 418	10 415	10 390	10 390
Net import ratio, %		-27%	-27%	-27%	-27%	-27%	8%	8%	22%	22%	22%	25%	25%	25%	25%	25%
Utilisation rates, %	Coal and lignite	62%	62%	62%	62%	62%	64%	64%	69%	69%	69%	64%	64%	64%	64%	64%
	Natural gas	13%	13%	13%	13%	13%	9%	9%	29%	29%	29%	21%	22%	22%	22%	22%
Baseload price, €/MWh		46.39	46.39	46.39	46.39	46.39	56.88	57.16	71.00	71.30	71.60	66.69	66.88	66.91	67.08	67.08
Additional RES support (€/MWh)							1.72				0.87	2.66				2.07
CO_2 emission (kt)		26 136	26 136	26 136	26 136	26 136	12 162	12 181	4 598	4 604	4 610	3 965	3 975	3 977	3 988	3 988

Table 21: Modelling results for Greece, Reference RES, Low CO2 price

GR REF RES, Low CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 189	4 189	4 189	4 189	4 189	4 890	4 890	4 890	4 890	4 890
	PV	4 593	4 593	4 593	4 593	4 593	6 546	6 546	6 546	6 546	6 546	8 976	8 976	8 976	8 976	8 976
	Wind	3 024	3 024	3 024	3 024	3 024	4 153	4 153	4 153	4 153	4 153	5 390	5 390	5 390	5 390	5 390
	Biomass and other RES	94	94	94	94	94	235	235	235	235	235	302	302	302	302	302
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	11 070	11 070	11 070	11 070	11 070	8 749	8 886	4 111	4 111	4 111	3 830	3 830	3 830	3 830	3 830
	Natural gas	20 185	20 185	20 185	20 185	20 185	21 082	21 232	24 363	24 364	24 364	20 035	20 038	20 052	20 064	20 064
	HFO/LFO	28	28	28	28	28	14	18	292	292	292	73	73	73	73	73
	Hydro	5 136	5 136	5 136	5 136	5 136	5 260	5 260	5 260	5 260	5 260	6 112	6 112	6 112	6 112	6 112
	PV	6 618	6 618	6 618	6 618	6 618	9 431	9 431	9 431	9 431	9 431	12 879	12 879	12 879	12 879	12 879
	Wind	5 308	5 308	5 308	5 308	5 308	7 291	7 291	7 291	7 291	7 291	9 449	9 449	9 449	9 449	9 449
	Biomass and other RES	451	451	451	451	451	1 131	1 131	1 131	1 131	1 131	1 454	1 454	1 454	1 454	1 454
	Total	48 797	48 797	48 797	48 797	48 797	52 959	53 249	51 879	51 880	51 880	53 832	53 835	53 849	53 861	53 861
Gross consumption, GWh		57 819	57 819	57 819	57 819	57 819	57 823	57 818	57 573	57 568	57 562	58 377	58 374	58 373	58 370	58 370
Net import, GWh	AL	1 944	1 944	1 944	1 944	1 944	1 243	1 054	2 011	2 013	2 001	1 366	1 356	1 392	1 407	1 407
	BG	4 380	4 380	4 380	4 380	4 380	1 875	1 455	-2 177	-2 186	-2 179	-5 403	-5 384	-5 401	-5 421	-5 421
	IT	-413	-413	-413	-413	-413	-773	-469	2 624	2 624	2 624	2 992	3 003	3 002	2 981	2 981

	MK	2 049	2 049	2 049	2 049	2 049	1 427	1 447	2 130	2 130	2 130	4 754	4 728	4 717	4 728	4 728
	TR	1 063	1 063	1 063	1 063	1 063	1 092	1 082	1 107	1 107	1 107	836	836	814	814	814
	Total	9 022	9 022	9 022	9 022	9 022	4 864	4 569	5 694	5 688	5 682	4 545	4 539	4 524	4 510	4 510
Net import ratio, %		16%	16%	16%	16%	16%	8%	8%	10%	10%	10%	8%	8%	8%	8%	8%
Utilisation rates, %	Coal and lignite	45%	45%	45%	45%	45%	35%	35%	71%	71%	71%	66%	66%	66%	66%	66%
	Natural gas	41%	41%	41%	41%	41%	38%	38%	43%	43%	43%	37%	37%	37%	37%	37%
Baseload price, €/MWh		54.83	54.83	54.83	54.83	54.83	56.88	57.16	71.00	71.30	71.60	65.69	65.89	65.91	66.09	66.09
Additional RES support (€/MWh)							2.96				2.08	4.91				4.78
CO_2 emission (kt)		20 135	20 135	20 135	20 135	20 135	17 098	17 314	13 360	13 361	13 361	11 293	11 294	11 299	11 305	11 305

Table 22: Modelling results for Romania, Reference RES, Low CO2 price

RO		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 589	7 589	7 589	7 589	7 589	8 168	8 168	8 168	8 168	8 168
	PV	1 499	1 499	1 499	1 499	1 499	1 669	1 669	1 669	1 669	1 669	1 910	1 910	1 910	1 910	1 910
	Wind	4 403	4 403	4 403	4 403	4 403	5 535	5 535	5 535	5 535	5 535	6 814	6 814	6 814	6 814	6 814
	Biomass and other RES	250	250	250	250	250	823	823	823	823	823	1 237	1 237	1 237	1 237	1 237
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 893	15 893	15 893	15 893	15 893
	Coal and lignite	9 704	9 704	9 704	9 704	9 704	4 977	1 954	1 629	1 336	1 042	2 123	1 311	868	0	0
	Natural gas	5 426	5 426	5 426	5 426	5 426	17 082	17 206	17 476	17 487	17 489	14 454	14 454	14 502	14 502	14 502
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 528	19 528	19 528	19 528	19 528	21 131	21 131	21 131	21 131	21 131
	PV	1 664	1 664	1 664	1 664	1 664	1 852	1 852	1 852	1 852	1 852	2 119	2 119	2 119	2 119	2 119
	Wind	10 042	10 042	10 042	10 042	10 042	12 622	12 622	12 622	12 622	12 622	15 539	15 539	15 539	15 539	15 539
	Biomass and other RES	552	552	552	552	552	2 235	2 235	2 235	2 235	2 235	3 372	3 372	3 372	3 372	3 372
	Total	55 814	55 814	55 814	55 814	55 814	68 929	66 030	65 975	65 692	65 399	74 631	73 819	73 424	72 556	72 556
Gross consumption, GWh		56 977	56 977	56 977	56 977	56 977	68 378	68 367	68 297	68 274	68 250	80 096	80 084	80 079	80 032	80 032
Net import, GWh	BG	2 252	2 252	2 252	2 252	2 252	-1 369	-1 080	-2 203	-2 167	-2 147	-1 704	-1 706	-1 601	-1 572	-1 572
	HU	-2 223	-2 223	-2 223	-2 223	-2 223	-1 654	-894	254	407	436	1 607	1 853	1 816	1 994	1 994
	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	RS	-1 030	-1 030	-1 030	-1 030	-1 030	2 108	3 412	3 382	3 386	3 632	5 234	5 785	6 174	6 753	6 753
	UA	2 165	2 165	2 165	2 165	2 165	365	900	890	955	930	328	332	266	302	302
	Total	1 163	1 163	1 163	1 163	1 163	-551	2 338	2 323	2 581	2 851	5 465	6 265	6 655	7 476	7 476
Net import ratio, %		2%	2%	2%	2%	2%	-1%	3%	3%	4%	4%	7%	8%	8%	9%	9%
Utilisation rates, %	Coal and lignite	30%	30%	30%	30%	30%	21%	11%	13%	14%	16%	17%	20%	15%	-	-
	Natural gas	21%	21%	21%	21%	21%	63%	63%	64%	64%	64%	49%	49%	49%	49%	49%
Baseload price, €/MWh		49.89	49.89	49.89	49.89	49.89	56.32	56.82	60.14	61.25	62.36	58.19	58.70	58.92	60.86	60.86
Additional RES support (€/MWh)							4.14				3.68	9.16				8.78
CO_2 emission (kt)		13 456	13 456	13 456	13 456	13 456	12 484	8 583	8 310	7 957	7 609	7 704	6 726	6 318	5 257	5 257

Table 23: Modelling results for Bulgaria, Low RES, Reference CO2 price

BG Low RES, REF CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 934	3 934	3 934	3 934	3 934	3 895	3 895	3 895	3 895	3 895	3 858	3 858	3 858	3 858	3 858
	PV	1 336	1 336	1 336	1 336	1 336	1 447	1 447	1 447	1 447	1 447	1 741	1 741	1 741	1 741	1 741
	Wind	698	698	698	698	698	689	689	689	689	689	231	231	231	231	231
	Biomass and other RES	139	139	139	139	139	228	228	228	228	228	328	328	328	328	328
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726
	Coal and lignite	21 777	21 777	21 777	21 777	21 777	10 421	10 421	2 462	2 462	2 462	2 462	2 462	2 462	2 462	2 462
	Natural gas	1 431	1 431	1 431	1 431	1 431	1 692	1 757	4 810	4 810	4 810	3 650	3 657	3 663	3 672	3 672
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 030	4 030	4 030	4 030	4 030	4 022	4 022	4 022	4 022	4 022	4 018	4 018	4 018	4 018	4 018
	PV	1 702	1 702	1 702	1 702	1 702	1 843	1 843	1 843	1 843	1 843	2 218	2 218	2 218	2 218	2 218
	Wind	1 085	1 085	1 085	1 085	1 085	1 070	1 070	1 070	1 070	1 070	359	359	359	359	359
	Biomass and other RES	462	462	462	462	462	864	864	864	864	864	1 378	1 378	1 378	1 378	1 378
	Total	45 873	45 873	45 873	45 873	45 873	35 297	35 362	30 456	30 456	30 456	29 470	29 478	29 483	29 493	29 493
Gross consumption, GWh		38 293	38 293	38 293	38 293	38 293	40 093	40 091	39 920	39 916	39 912	41 389	41 388	41 387	41 384	41 384
Net import, GWh	GR	-4 357	-4 357	-4 357	-4 357	-4 357	32	15	2 985	2 981	3 010	6 551	6 484	6 553	6 569	6 569
	MK	-1 701	-1 701	-1 701	-1 701	-1 701	601	596	815	815	815	641	649	597	612	612
	RO	-2 030	-2 030	-2 030	-2 030	-2 030	904	822	2 000	2 000	1 967	1 411	1 477	1 474	1 418	1 418

	RS	-2 074	-2 074	-2 074	-2 074	-2 074	715	751	1 139	1 139	1 139	759	743	724	736	736
	TR	2 583	2 583	2 583	2 583	2 583	2 545	2 545	2 525	2 525	2 525	2 557	2 557	2 557	2 557	2 557
	Total	-7 579	-7 579	-7 579	-7 579	-7 579	4 796	4 729	9 464	9 460	9 456	11 919	11 910	11 904	11 892	11 892
Net import ratio, %		-20%	-20%	-20%	-20%	-20%	12%	12%	24%	24%	24%	29%	29%	29%	29%	29%
Utilisation rates, %	Coal and lignite	55%	55%	55%	55%	55%	59%	59%	67%	67%	67%	67%	67%	67%	67%	67%
	Natural gas	15%	15%	15%	15%	15%	12%	13%	35%	35%	35%	26%	26%	26%	27%	27%
Baseload price, €/MWh		58.41	58.41	58.41	58.41	58.41	67.55	67.74	81.20	81.49	81.78	78.10	78.24	78.26	78.50	78.50
Additional RES support (€/MWh)							0.06				0.01	0.13				0.07
CO_2 emission (kt)		23 073	23 073	23 073	23 073	23 073	11 521	11 552	4 941	4 941	4 941	4 375	4 378	4 381	4 386	4 386

Table 24: Modelling results for Greece, Low RES, Reference CO2 price

GR Low RES, REF CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 116	4 116	4 116	4 116	4 116	4 817	4 817	4 817	4 817	4 817
	PV	4 593	4 593	4 593	4 593	4 593	5 728	5 728	5 728	5 728	5 728	8 150	8 150	8 150	8 150	8 150
	Wind	3 024	3 024	3 024	3 024	3 024	3 561	3 561	3 561	3 561	3 561	5 079	5 079	5 079	5 079	5 079
	Biomass and other RES	94	94	94	94	94	221	221	221	221	221	308	308	308	308	308
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	5 142	5 142	5 142	5 142	5 142	3 537	3 597	2 866	2 866	2 866	2 519	2 519	2 519	2 519	2 519
	Natural gas	22 554	22 554	22 554	22 554	22 554	25 752	25 765	27 311	27 311	27 312	23 729	23 731	23 732	23 734	23 734
	HFO/LFO	27	27	27	27	27	20	20	354	354	354	73	73	73	73	73
	Hydro	5 136	5 136	5 136	5 136	5 136	5 168	5 168	5 168	5 168	5 168	6 024	6 024	6 024	6 024	6 024
	PV	6 618	6 618	6 618	6 618	6 618	8 253	8 253	8 253	8 253	8 253	11 734	11 734	11 734	11 734	11 734
	Wind	5 308	5 308	5 308	5 308	5 308	6 252	6 252	6 252	6 252	6 252	8 915	8 915	8 915	8 915	8 915
	Biomass and other RES	451	451	451	451	451	1 065	1 065	1 065	1 065	1 065	1 482	1 482	1 482	1 482	1 482
	Total	45 237	45 237	45 237	45 237	45 237	50 047	50 121	51 268	51 268	51 270	54 476	54 478	54 480	54 481	54 481
Gross consumption, GWh		57 639	57 639	57 639	57 639	57 639	57 645	57 642	57 402	57 397	57 392	58 196	58 194	58 193	58 189	58 189
Net import, GWh	AL	1 697	1 697	1 697	1 697	1 697	1 585	1 651	1 824	1 844	1 837	911	878	823	820	820
	BG	4 357	4 357	4 357	4 357	4 357	-32	-15	-2 985	-2 981	-3 010	-6 551	-6 484	-6 553	-6 569	-6 569
	IT	3 337	3 337	3 337	3 337	3 337	3 110	3 118	3 980	3 980	3 980	3 455	3 411	3 535	3 551	3 551

	MK	1 837	1 837	1 837	1 837	1 837	1 816	1 648	2 168	2 138	2 168	4 819	4 825	4 824	4 821	4 821
	TR	1 174	1 174	1 174	1 174	1 174	1 119	1 119	1 147	1 147	1 147	1 085	1 085	1 085	1 085	1 085
	Total	12 402	12 402	12 402	12 402	12 402	7 598	7 521	6 134	6 129	6 122	3 720	3 716	3 714	3 708	3 708
Net import ratio, %		22%	22%	22%	22%	22%	13%	13%	11%	11%	11%	6%	6%	6%	6%	6%
Utilisation rates, %	Coal and lignite	21%	21%	21%	21%	21%	14%	14%	50%	50%	50%	44%	44%	44%	44%	44%
	Natural gas	46%	46%	46%	46%	46%	46%	46%	49%	49%	49%	44%	44%	44%	44%	44%
Baseload price, €/MWh		65.69	65.69	65.69	65.69	65.69	67.55	67.74	81.15	81.44	81.74	76.44	76.57	76.60	76.83	76.83
Additional RES support (€/MWh)							0.58				0.36	0.94				0.90
CO_2 emission (kt)		14 283	14 283	14 283	14 283	14 283	13 247	13 323	13 268	13 268	13 269	11 365	11 366	11 367	11 367	11 367

Table 25: Modelling results for Romania, Low RES, Reference CO2 price

RO		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 543	7 543	7 543	7 543	7 543	7 713	7 713	7 713	7 713	7 713
	PV	1 499	1 499	1 499	1 499	1 499	1 566	1 566	1 566	1 566	1 566	1 653	1 653	1 653	1 653	1 653
	Wind	4 403	4 403	4 403	4 403	4 403	4 545	4 545	4 545	4 545	4 545	4 692	4 692	4 692	4 692	4 692
	Biomass and other RES	250	250	250	250	250	639	639	639	639	639	882	882	882	882	882
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 899	15 899	15 899	15 899	15 899
	Coal and lignite	3 160	3 160	3 160	3 160	3 160	938	449	574	479	370	705	458	280	0	0
	Natural gas	10 436	10 436	10 436	10 436	10 436	19 132	19 136	19 201	19 201	19 204	18 214	18 214	18 214	18 214	18 214
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 414	19 414	19 414	19 414	19 414	19 987	19 987	19 987	19 987	19 987
	PV	1 664	1 664	1 664	1 664	1 664	1 737	1 737	1 737	1 737	1 737	1 833	1 833	1 833	1 833	1 833
	Wind	10 042	10 042	10 042	10 042	10 042	10 364	10 364	10 364	10 364	10 364	10 699	10 699	10 699	10 699	10 699
	Biomass and other RES	554	554	554	554	554	1 621	1 621	1 621	1 621	1 621	2 046	2 046	2 046	2 046	2 046
	Total	54 282	54 282	54 282	54 282	54 282	63 837	63 352	63 542	63 447	63 341	69 384	69 137	68 959	68 679	68 679
Gross consumption, GWh		56 808	56 808	56 808	56 808	56 808	68 185	68 179	68 103	68 077	68 050	79 865	79 838	79 831	79 789	79 789
Net import, GWh	BG	2 030	2 030	2 030	2 030	2 030	-904	-822	-2 000	-2 000	-1 967	-1 411	-1 477	-1 474	-1 418	-1 418
	HU	-1 141	-1 141	-1 141	-1 141	-1 141	-1 890	-1 637	-608	-594	-553	4 770	4 868	4 935	4 969	4 969
	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	RS	-50	-50	-50	-50	-50	6 456	6 553	6 386	6 438	6 434	6 759	6 942	7 038	7 141	7 141

	UA	1 688	1 688	1 688	1 688	1 688	687	733	784	787	794	363	368	374	418	418
	Total	2 526	2 526	2 526	2 526	2 526	4 348	4 827	4 562	4 630	4 708	10 480	10 702	10 873	11 110	11 110
Net import ratio, %		4%	4%	4%	4%	4%	6%	7%	7%	7%	7%	13%	13%	14%	14%	14%
Utilisation rates, %	Coal and lignite	10%	10%	10%	10%	10%	4%	2%	5%	5%	6%	6%	7%	5%	-	-
	Natural gas	41%	41%	41%	41%	41%	70%	71%	71%	71%	71%	62%	62%	62%	62%	62%
Baseload price, €/MWh		60.20	60.20	60.20	60.20	60.20	66.08	66.35	69.94	71.18	72.47	68.29	69.38	69.66	71.44	71.44
Additional RES support (€/MWh)							1.30				0.89	2.39				2.08
CO_2 emission (kt)		7 478	7 478	7 478	7 478	7 478	8 184	7 545	7 732	7 616	7 489	7 416	7 119	6 949	6 607	6 607

Table 26: Modelling results for Bulgaria, Low RES, High CO2 price

BG Low RES, High CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 934	3 934	3 934	3 934	3 934	3 895	3 895	3 895	3 895	3 895	3 858	3 858	3 858	3 858	3 858
	PV	1 336	1 336	1 336	1 336	1 336	1 447	1 447	1 447	1 447	1 447	1 741	1 741	1 741	1 741	1 741
	Wind	698	698	698	698	698	689	689	689	689	689	231	231	231	231	231
	Biomass and other RES	139	139	139	139	139	228	228	228	228	228	328	328	328	328	328
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726
	Coal and lignite	17 311	17 311	17 311	17 311	17 311	7 917	7 917	2 286	2 286	2 286	2 186	2 186	2 186	2 186	2 186
	Natural gas	1 679	1 679	1 679	1 679	1 679	2 394	2 394	4 689	4 689	4 689	3 278	3 278	3 282	3 282	3 282
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 030	4 030	4 030	4 030	4 030	4 022	4 022	4 022	4 022	4 022	4 018	4 018	4 018	4 018	4 018
	PV	1 702	1 702	1 702	1 702	1 702	1 843	1 843	1 843	1 843	1 843	2 218	2 218	2 218	2 218	2 218
	Wind	1 085	1 085	1 085	1 085	1 085	1 070	1 070	1 070	1 070	1 070	359	359	359	359	359
	Biomass and other RES	462	462	462	462	462	864	864	864	864	864	1 378	1 378	1 378	1 378	1 378
	Total	41 655	41 655	41 655	41 655	41 655	33 495	33 495	30 160	30 160	30 160	28 823	28 823	28 827	28 827	28 827
Gross consumption, GWh		38 153	38 153	38 153	38 153	38 153	39 971	39 971	39 822	39 818	39 814	41 290	41 291	41 291	41 288	41 288
Net import, GWh	GR	-3 529	-3 529	-3 529	-3 529	-3 529	1 835	1 832	3 762	3 758	3 785	7 340	7 341	7 314	7 310	7 310
	MK	-879	-879	-879	-879	-879	597	610	757	757	757	559	559	565	566	566
	RO	-751	-751	-751	-751	-751	977	965	1 606	1 606	1 575	1 445	1 444	1 432	1 435	1 435

	RS	-971	-971	-971	-971	-971	522	523	966	966	966	553	555	583	580	580
	TR	2 628	2 628	2 628	2 628	2 628	2 544	2 544	2 572	2 572	2 572	2 570	2 570	2 570	2 570	2 570
	Total	-3 502	-3 502	-3 502	-3 502	-3 502	6 476	6 476	9 662	9 659	9 655	12 467	12 468	12 464	12 461	12 461
Net import ratio, %		-9%	-9%	-9%	-9%	-9%	16%	16%	24%	24%	24%	30%	30%	30%	30%	30%
Utilisation rates, %	Coal and lignite	44%	44%	44%	44%	44%	45%	45%	62%	62%	62%	59%	59%	59%	59%	59%
	Natural gas	18%	18%	18%	18%	18%	17%	17%	34%	34%	34%	24%	24%	24%	24%	24%
Baseload price, €/MWh		71.14	71.14	71.14	71.14	71.14	78.05	78.05	89.67	89.96	90.26	86.46	86.39	86.41	86.64	86.64
Additional RES support (€/MWh)							0.01				0.00	0.06				0.02
CO_2 emission (kt)		18 490	18 490	18 490	18 490	18 490	9 330	9 330	4 718	4 718	4 718	3 935	3 935	3 937	3 937	3 937

Table 27: Modelling results for Greece, Low RES, High CO2 price

GR Low RES, High CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 116	4 116	4 116	4 116	4 116	4 817	4 817	4 817	4 817	4 817
	PV	4 593	4 593	4 593	4 593	4 593	5 728	5 728	5 728	5 728	5 728	8 150	8 150	8 150	8 150	8 150
	Wind	3 024	3 024	3 024	3 024	3 024	3 561	3 561	3 561	3 561	3 561	5 079	5 079	5 079	5 079	5 079
	Biomass and other RES	94	94	94	94	94	221	221	221	221	221	308	308	308	308	308
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	3 775	3 775	3 775	3 775	3 775	2 319	2 379	2 789	2 789	2 789	2 376	2 376	2 377	2 377	2 377
	Natural gas	24 528	24 528	24 528	24 528	24 528	27 812	27 824	28 290	28 290	28 290	25 626	25 626	25 627	25 627	25 627
	HFO/LFO	21	21	21	21	21	27	20	339	339	339	73	73	73	73	73
	Hydro	5 136	5 136	5 136	5 136	5 136	5 168	5 168	5 168	5 168	5 168	6 024	6 024	6 024	6 024	6 024
	PV	6 618	6 618	6 618	6 618	6 618	8 253	8 253	8 253	8 253	8 253	11 734	11 734	11 734	11 734	11 734
	Wind	5 308	5 308	5 308	5 308	5 308	6 252	6 252	6 252	6 252	6 252	8 915	8 915	8 915	8 915	8 915
	Biomass and other RES	451	451	451	451	451	1 065	1 065	1 065	1 065	1 065	1 482	1 482	1 482	1 482	1 482
	Total	45 839	45 839	45 839	45 839	45 839	50 896	50 960	52 155	52 155	52 155	56 230	56 230	56 232	56 232	56 232
Gross consumption, GWh		57 421	57 421	57 421	57 421	57 421	57 472	57 472	57 264	57 259	57 254	58 057	58 058	58 058	58 054	58 054
Net import, GWh	AL	1 290	1 290	1 290	1 290	1 290	1 671	1 653	1 808	1 808	1 809	803	802	796	793	793
	BG	3 529	3 529	3 529	3 529	3 529	-1 835	-1 832	-3 762	-3 758	-3 785	-7 340	-7 341	-7 314	-7 310	-7 310
	IT	4 043	4 043	4 043	4 043	4 043	3 923	3 905	4 045	4 045	4 045	3 570	3 570	3 575	3 573	3 573

	MK	1 547	1 547	1 547	1 547	1 547	1 666	1 634	1 887	1 878	1 900	3 709	3 711	3 684	3 681	3 681
	TR	1 174	1 174	1 174	1 174	1 174	1 151	1 151	1 130	1 130	1 130	1 085	1 085	1 085	1 085	1 085
	Total	11 582	11 582	11 582	11 582	11 582	6 576	6 512	5 109	5 104	5 099	1 827	1 828	1 826	1 822	1 822
Net import ratio, %		20%	20%	20%	20%	20%	11%	11%	9%	9%	9%	3%	3%	3%	3%	3%
Utilisation rates, %	Coal and lignite	15%	15%	15%	15%	15%	9%	9%	48%	48%	48%	41%	41%	41%	41%	41%
	Natural gas	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	48%	48%	48%	48%	48%
Baseload price, €/MWh		78.76	78.76	78.76	78.76	78.76	77.93	77.93	89.46	89.75	90.04	84.68	84.62	84.64	84.87	84.87
Additional RES support (€/MWh)							0.19				0.13	0.27				0.24
CO_2 emission (kt)		13 577	13 577	13 577	13 577	13 577	12 738	12 808	13 571	13 571	13 571	11 947	11 947	11 948	11 948	11 948

Table 28: Modelling results for Romania, Low RES, High CO2 price

RO Low RES, High CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 543	7 543	7 543	7 543	7 543	7 713	7 713	7 713	7 713	7 713
	PV	1 499	1 499	1 499	1 499	1 499	1 566	1 566	1 566	1 566	1 566	1 653	1 653	1 653	1 653	1 653
	Wind	4 403	4 403	4 403	4 403	4 403	4 545	4 545	4 545	4 545	4 545	4 692	4 692	4 692	4 692	4 692
	Biomass and other RES	250	250	250	250	250	639	639	639	639	639	882	882	882	882	882
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 899	15 899	15 899	15 899	15 899
	Coal and lignite	1 481	1 481	1 481	1 481	1 481	407	307	481	411	327	240	312	150	0	0
	Natural gas	15 466	15 466	15 466	15 466	15 466	19 271	19 273	19 291	19 291	19 291	22 255	22 255	22 255	22 255	22 255
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 414	19 414	19 414	19 414	19 414	19 987	19 987	19 987	19 987	19 987
	PV	1 664	1 664	1 664	1 664	1 664	1 737	1 737	1 737	1 737	1 737	1 833	1 833	1 833	1 833	1 833
	Wind	10 042	10 042	10 042	10 042	10 042	10 364	10 364	10 364	10 364	10 364	10 699	10 699	10 699	10 699	10 699
	Biomass and other RES	554	554	554	554	554	1 621	1 621	1 621	1 621	1 621	2 046	2 046	2 046	2 046	2 046
	Total	57 632	57 632	57 632	57 632	57 632	63 445	63 347	63 539	63 468	63 384	72 960	73 032	72 870	72 720	72 720
Gross consumption, GWh		56 619	56 619	56 619	56 619	56 619	67 983	67 983	67 921	67 897	67 870	79 594	79 615	79 609	79 567	79 567
Net import, GWh	BG	751	751	751	751	751	-977	-965	-1 606	-1 606	-1 575	-1 445	-1 444	-1 432	-1 435	-1 435
	HU	-2 324	-2 324	-2 324	-2 324	-2 324	-1 510	-1 494	-1 280	-1 280	-1 273	2 937	2 911	2 902	2 954	2 954
	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	RS	-407	-407	-407	-407	-407	6 529	6 572	6 657	6 697	6 714	4 949	4 937	5 139	5 179	5 179

	UA	967	967	967	967	967	496	524	612	618	620	194	179	131	150	150
	Total	-1 013	-1 013	-1 013	-1 013	-1 013	4 538	4 637	4 382	4 429	4 486	6 634	6 583	6 739	6 847	6 847
Net import ratio, %		-2%	-2%	-2%	-2%	-2%	7%	7%	6%	7%	7%	8%	8%	8%	9%	9%
Utilisation rates, %	Coal and lignite	5%	5%	5%	5%	5%	2%	2%	4%	4%	5%	2%	5%	3%	-	-
	Natural gas	61%	61%	61%	61%	61%	71%	71%	71%	71%	71%	76%	76%	76%	76%	76%
Baseload price, €/MWh		71.74	71.74	71.74	71.74	71.74	76.29	76.29	79.23	80.35	81.63	79.92	79.06	79.30	81.06	81.06
Additional RES support (€/MWh)							0.59				0.37	1.01				0.98
CO_2 emission (kt)		7 440	7 440	7 440	7 440	7 440	7 575	7 438	7 659	7 573	7 473	8 342	8 432	8 277	8 093	8 093

Table 29: Modelling results for Bulgaria, Low RES, Low CO2 price

BG Low RES, Low CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 934	3 934	3 934	3 934	3 934	3 895	3 895	3 895	3 895	3 895	3 858	3 858	3 858	3 858	3 858
	PV	1 336	1 336	1 336	1 336	1 336	1 447	1 447	1 447	1 447	1 447	1 741	1 741	1 741	1 741	1 741
	Wind	698	698	698	698	698	689	689	689	689	689	231	231	231	231	231
	Biomass and other RES	139	139	139	139	139	228	228	228	228	228	328	328	328	328	328
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726
	Coal and lignite	24 642	24 642	24 642	24 642	24 642	11 449	11 449	2 570	2 570	2 570	2 459	2 459	2 459	2 459	2 459
	Natural gas	1 225	1 225	1 225	1 225	1 225	1 304	1 359	4 598	4 600	4 602	3 431	3 457	3 465	3 519	3 519
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 030	4 030	4 030	4 030	4 030	4 022	4 022	4 022	4 022	4 022	4 018	4 018	4 018	4 018	4 018
	PV	1 702	1 702	1 702	1 702	1 702	1 843	1 843	1 843	1 843	1 843	2 218	2 218	2 218	2 218	2 218
	Wind	1 085	1 085	1 085	1 085	1 085	1 070	1 070	1 070	1 070	1 070	359	359	359	359	359
	Biomass and other RES	462	462	462	462	462	864	864	864	864	864	1 378	1 378	1 378	1 378	1 378
	Total	48 533	48 533	48 533	48 533	48 533	35 937	35 993	30 353	30 354	30 357	29 248	29 274	29 283	29 337	29 337
Gross consumption, GWh		38 425	38 425	38 425	38 425	38 425	40 207	40 204	39 998	39 994	39 989	41 472	41 470	41 470	41 467	41 467
Net import, GWh	GR	-4 374	-4 374	-4 374	-4 374	-4 374	-1 325	-1 087	2 459	2 485	2 492	6 165	6 162	6 178	6 127	6 127
	MK	-1 667	-1 667	-1 667	-1 667	-1 667	558	586	866	863	865	620	646	590	603	603
	RO	-2 275	-2 275	-2 275	-2 275	-2 275	1 733	1 488	2 490	2 443	2 427	1 797	1 748	1 799	1 775	1 775

	RS	-2 140	-2 140	-2 140	-2 140	-2 140	791	705	1 305	1 323	1 323	1 210	1 208	1 186	1 190	1 190
	TR	348	348	348	348	348	2 512	2 520	2 526	2 526	2 526	2 432	2 432	2 435	2 435	2 435
	Total	-10 108	-10 108	-10 108	-10 108	-10 108	4 270	4 211	9 646	9 640	9 633	12 224	12 196	12 187	12 130	12 130
Net import ratio, %		-26%	-26%	-26%	-26%	-26%	11%	10%	24%	24%	24%	29%	29%	29%	29%	29%
Utilisation rates, %	Coal and lignite	63%	63%	63%	63%	63%	65%	65%	70%	70%	70%	67%	67%	67%	67%	67%
	Natural gas	13%	13%	13%	13%	13%	9%	10%	33%	33%	33%	25%	25%	25%	25%	25%
Baseload price, €/MWh		46.52	46.52	46.52	46.52	46.52	57.79	58.03	74.41	74.74	75.07	71.05	71.21	71.24	71.49	71.49
Additional RES support (€/MWh)							0.15				0.05	0.31				0.27
CO_2 emission (kt)		26 255	26 255	26 255	26 255	26 255	12 380	12 408	4 942	4 943	4 944	4 273	4 286	4 290	4 317	4 317

Table 30: Modelling results for Greece, Low RES, Low CO2 price

GR Low RES, Low CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 116	4 116	4 116	4 116	4 116	4 817	4 817	4 817	4 817	4 817
	PV	4 593	4 593	4 593	4 593	4 593	5 728	5 728	5 728	5 728	5 728	8 150	8 150	8 150	8 150	8 150
	Wind	3 024	3 024	3 024	3 024	3 024	3 561	3 561	3 561	3 561	3 561	5 079	5 079	5 079	5 079	5 079
	Biomass and other RES	94	94	94	94	94	221	221	221	221	221	308	308	308	308	308
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	11 071	11 071	11 071	11 071	11 071	9 266	9 356	4 406	4 406	4 406	4 077	4 077	4 077	4 077	4 077
	Natural gas	20 186	20 186	20 186	20 186	20 186	22 113	22 259	25 899	25 900	25 925	20 875	20 888	20 901	20 908	20 908
	HFO/LFO	28	28	28	28	28	18	23	367	367	367	73	73	73	73	73
	Hydro	5 136	5 136	5 136	5 136	5 136	5 168	5 168	5 168	5 168	5 168	6 024	6 024	6 024	6 024	6 024
	PV	6 618	6 618	6 618	6 618	6 618	8 253	8 253	8 253	8 253	8 253	11 734	11 734	11 734	11 734	11 734
	Wind	5 308	5 308	5 308	5 308	5 308	6 252	6 252	6 252	6 252	6 252	8 915	8 915	8 915	8 915	8 915
	Biomass and other RES	451	451	451	451	451	1 065	1 065	1 065	1 065	1 065	1 482	1 482	1 482	1 482	1 482
	Total	48 799	48 799	48 799	48 799	48 799	52 136	52 377	51 411	51 411	51 436	53 180	53 193	53 206	53 213	53 213
Gross consumption, GWh		57 819	57 819	57 819	57 819	57 819	57 808	57 804	57 515	57 509	57 503	58 311	58 308	58 307	58 303	58 303
Net import GWh	AL	1 907	1 907	1 907	1 907	1 907	1 518	1 525	2 032	2 052	2 042	1 436	1 418	1 404	1 363	1 363
	BG	4 374	4 374	4 374	4 374	4 374	1 325	1 087	-2 459	-2 485	-2 492	-6 165	-6 162	-6 178	-6 127	-6 127
	IT	-434	-434	-434	-434	-434	14	115	3 159	3 159	3 159	3 445	3 458	3 397	3 423	3 423

	MK	2 110	2 110	2 110	2 110	2 110	1 694	1 587	2 250	2 250	2 235	5 403	5 391	5 470	5 423	5 423
	TR	1 063	1 063	1 063	1 063	1 063	1 121	1 113	1 122	1 122	1 122	1 011	1 011	1 008	1 008	1 008
	Total	9 020	9 020	9 020	9 020	9 020	5 672	5 427	6 105	6 098	6 066	5 130	5 115	5 101	5 090	5 090
Net import ratio, %		16%	16%	16%	16%	16%	10%	9%	11%	11%	11%	9%	9%	9%	9%	9%
Utilisation rates, %	Coal and lignite	45%	45%	45%	45%	45%	37%	37%	76%	76%	76%	71%	71%	71%	71%	71%
	Natural gas	41%	41%	41%	41%	41%	39%	40%	46%	46%	46%	39%	39%	39%	39%	39%
Baseload price, €/MWh		54.83	54.83	54.83	54.83	54.83	57.79	58.03	74.32	74.66	75.04	69.58	69.74	69.77	70.02	70.02
Additional RES support (€/MWh)							1.49				1.00	3.37				3.24
CO_2 emission (kt)		20 137	20 137	20 137	20 137	20 137	18 044	18 204	14 277	14 277	14 289	11 853	11 859	11 864	11 867	11 867

Table 31: Modelling results for Romania, Low RES, Low CO2 price

RO Low RES, Low CO_2		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 543	7 543	7 543	7 543	7 543	7 713	7 713	7 713	7 713	7 713
	PV	1 499	1 499	1 499	1 499	1 499	1 566	1 566	1 566	1 566	1 566	1 653	1 653	1 653	1 653	1 653
	Wind	4 403	4 403	4 403	4 403	4 403	4 545	4 545	4 545	4 545	4 545	4 692	4 692	4 692	4 692	4 692
	Biomass and other RES	250	250	250	250	250	639	639	639	639	639	882	882	882	882	882
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 899	15 899	15 899	15 899	15 899
	Coal and lignite	9 712	9 712	9 712	9 712	9 712	5 195	2 076	1 810	1 506	1 172	2 251	1 381	902	0	0
	Natural gas	5 433	5 433	5 433	5 433	5 433	17 532	17 669	17 823	17 827	17 832	15 291	15 291	15 357	15 357	15 357
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 414	19 414	19 414	19 414	19 414	19 987	19 987	19 987	19 987	19 987
	PV	1 664	1 664	1 664	1 664	1 664	1 737	1 737	1 737	1 737	1 737	1 833	1 833	1 833	1 833	1 833
	Wind	10 042	10 042	10 042	10 042	10 042	10 364	10 364	10 364	10 364	10 364	10 699	10 699	10 699	10 699	10 699
	Biomass and other RES	554	554	554	554	554	1 621	1 621	1 621	1 621	1 621	2 046	2 046	2 046	2 046	2 046
	Total	55 830	55 830	55 830	55 830	55 830	66 494	63 511	63 400	63 100	62 771	68 006	67 137	66 724	65 822	65 822
Gross consumption, GWh		56 977	56 977	56 977	56 977	56 977	68 365	68 356	68 266	68 239	68 210	80 056	80 018	80 011	79 967	79 967
Net import, GWh	BG	2 275	2 275	2 275	2 275	2 275	-1 733	-1 488	-2 490	-2 443	-2 427	-1 797	-1 748	-1 799	-1 775	-1 775
	HU	-598	-598	-598	-598	-598	1 344	1 058	2 709	2 772	2 799	5 354	5 468	6 028	6 050	6 050
	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	RS	-2 231	-2 231	-2 231	-2 231	-2 231	1 519	4 061	3 409	3 512	3 772	7 480	8 022	7 983	8 739	8 739
	UA	1 701	1 701	1 701	1 701	1 701	741	1 213	1 239	1 298	1 295	1 014	1 139	1 074	1 131	1 131
	Total	1 147	1 147	1 147	1 147	1 147	1 871	4 844	4 867	5 139	5 439	12 050	12 881	13 286	14 145	14 145
Net import ratio, %		2%	2%	2%	2%	2%	3%	7%	7%	8%	8%	15%	16%	17%	18%	18%
RES-E share, %																
Utilisation rates, %	Coal and lignite	30%	30%	30%	30%	30%	22%	11%	15%	16%	18%	18%	21%	16%	-	-
	Natural gas	21%	21%	21%	21%	21%	65%	65%	66%	66%	66%	52%	52%	52%	52%	52%
Baseload price, €/MWh		49.89	49.89	49.89	49.89	49.89	56.96	57.42	61.63	62.95	64.30	59.96	61.55	61.85	63.66	63.66
Additional RES support (€/MWh)							2.15				1.58	4.01				3.55
CO_2 emission (kt)		13 468	13 468	13 468	13 468	13 468	12 918	8 897	8 655	8 285	7 893	8 153	7 106	6 669	5 566	5 566

Table 32: Modelling results for Bulgaria, Reference RES, Reference CO2 price, Energy Efficiency

BG REF RES, REF CO_2, EE		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	2 000	3 000	3 000	3 000	3 000	3 000
	Coal and lignite	4 493	4 493	4 493	4 493	4 493	2 011	2 011	422	422	422	422	422	422	422	422
	Natural gas	1 072	1 072	1 072	1 072	1 072	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579	1 579
	HFO/LFO	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
	Hydro (incl. pumped storage)	3 946	3 946	3 946	3 946	3 946	3 969	3 969	3 969	3 969	3 969	3 978	3 978	3 978	3 978	3 978
	PV	1 490	1 490	1 490	1 490	1 490	2 348	2 348	2 348	2 348	2 348	2 959	2 959	2 959	2 959	2 959
	Wind	698	698	698	698	698	699	699	699	699	699	295	295	295	295	295
	Biomass and other RES	139	139	139	139	139	292	292	292	292	292	485	485	485	485	485
Net electricity generation, GWh	Nuclear	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 726	14 430	14 430	14 430	14 430	14 430
	Coal and lignite	20 783	20 783	20 783	20 783	20 783	9 353	9 353	2 322	2 322	2 322	2 154	2 154	2 154	2 154	2 154
	Natural gas	1 407	1 407	1 407	1 407	1 407	1 298	1 341	2 257	2 257	2 257	1 650	1 656	1 659	1 666	1 666
	HFO/LFO	659	659	659	659	659	659	659	659	659	659	659	659	659	659	659
	Hydro	4 043	4 043	4 043	4 043	4 043	4 106	4 106	4 106	4 106	4 106	4 153	4 153	4 153	4 153	4 153
	PV	1 899	1 899	1 899	1 899	1 899	2 991	2 991	2 991	2 991	2 991	3 770	3 770	3 770	3 770	3 770
	Wind	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	1 085	458	458	458	458	458
	Biomass and other RES	462	462	462	462	462	1 074	1 074	1 074	1 074	1 074	2 023	2 023	2 023	2 023	2 023
	Total	45 063	45 063	45 063	45 063	45 063	35 292	35 336	29 221	29 221	29 221	29 299	29 305	29 308	29 315	29 315
Gross consumption, GWh		36 953	36 953	36 953	36 953	36 953	37 481	37 481	37 431	37 431	37 429	38 143	38 142	38 142	38 141	38 141
Net import, GWh	GR	-4 380	-4 380	-4 380	-4 380	-4 380	-1 540	-1 453	2 653	2 665	2 656	5 988	5 988	5 941	5 968	5 968
	MK	-1 681	-1 681	-1 681	-1 681	-1 681	371	370	633	633	633	158	143	174	177	177
	RO	-2 376	-2 376	-2 376	-2 376	-2 376	650	582	1 694	1 693	1 690	634	634	649	637	637
	RS	-2 194	-2 194	-2 194	-2 194	-2 194	295	232	805	794	805	123	131	129	104	104

	TR	2 521	2 521	2 521	2 521	2 521	2 413	2 413	2 424	2 424	2 424	1 942	1 942	1 942	1 942	1 942
	Total	-8 110	-8 110	-8 110	-8 110	-8 110	2 189	2 145	8 210	8 210	8 208	8 844	8 838	8 834	8 827	8 827
Net import ratio, %		-22%	-22%	-22%	-22%	-22%	6%	6%	22%	22%	22%	23%	23%	23%	23%	23%
Utilisation rates, %	Coal and lignite	53%	53%	53%	53%	53%	53%	53%	63%	63%	63%	58%	58%	58%	58%	58%
	Natural gas	15%	15%	15%	15%	15%	9%	10%	16%	16%	16%	12%	12%	12%	12%	12%
Baseload price, €/MWh		57.48	57.48	57.48	57.48	57.48	63.58	63.63	67.78	67.80	67.95	62.68	62.73	62.74	62.81	62.81
CO_2 emission (kt)		21 999	21 999	21 999	21 999	21 999	10 263	10 284	3 569	3 569	3 569	3 132	3 135	3 136	3 139	3 139

Table 33: Modelling results for Greece, Reference RES, Reference CO2 price, Energy Efficiency

GR REF RES, REF CO_2, EE		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	2 825	2 825	2 825	2 825	2 825	2 885	2 885	660	660	660	660	660	660	660	660
	Natural gas	5 577	5 577	5 577	5 577	5 577	6 403	6 403	6 403	6 403	6 403	6 153	6 153	6 153	6 153	6 153
	HFO/LFO	1 795	1 795	1 795	1 795	1 795	974	974	974	974	974	343	343	343	343	343
	Hydro (incl. pumped storage)	4 091	4 091	4 091	4 091	4 091	4 189	4 189	4 189	4 189	4 189	4 890	4 890	4 890	4 890	4 890
	PV	4 593	4 593	4 593	4 593	4 593	6 546	6 546	6 546	6 546	6 546	8 976	8 976	8 976	8 976	8 976
	Wind	3 024	3 024	3 024	3 024	3 024	4 153	4 153	4 153	4 153	4 153	5 390	5 390	5 390	5 390	5 390
	Biomass and other RES	94	94	94	94	94	235	235	235	235	235	302	302	302	302	302
Net electricity generation, GWh	Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Coal and lignite	4 517	4 517	4 517	4 517	4 517	1 612	1 675	2 020	2 020	2 020	1 563	1 563	1 564	1 564	1 564
	Natural gas	22 333	22 333	22 333	22 333	22 333	22 562	22 572	23 793	23 796	23 799	20 723	20 725	20 726	20 727	20 727
	HFO/LFO	13	13	13	13	13	0	0	52	52	52	26	26	26	26	26
	Hydro	5 136	5 136	5 136	5 136	5 136	5 260	5 260	5 260	5 260	5 260	6 100	6 100	6 100	6 100	6 100
	PV	6 618	6 618	6 618	6 618	6 618	9 431	9 431	9 431	9 431	9 431	12 771	12 771	12 771	12 771	12 771
	Wind	5 308	5 308	5 308	5 308	5 308	7 291	7 291	7 291	7 291	7 291	9 425	9 425	9 425	9 425	9 425
	Biomass and other RES	451	451	451	451	451	1 131	1 131	1 131	1 131	1 131	1 451	1 451	1 451	1 451	1 451
	Total	44 377	44 377	44 377	44 377	44 377	47 287	47 361	48 979	48 982	48 984	52 059	52 061	52 063	52 064	52 064
Gross consumption, GWh		56 387	56 387	56 387	56 387	56 387	53 389	53 388	53 320	53 320	53 318	51 237	51 236	51 236	51 235	51 235
Net import, GWh	AL	1 547	1 547	1 547	1 547	1 547	992	1 015	1 732	1 729	1 727	136	137	172	213	213
	BG	4 380	4 380	4 380	4 380	4 380	1 540	1 453	-2 653	-2 665	-2 656	-5 988	-5 988	-5 941	-5 968	-5 968
	IT	3 155	3 155	3 155	3 155	3 155	1 049	1 059	2 537	2 543	2 543	1 536	1 546	1 550	1 533	1 533

	MK	1 754	1 754	1 754	1 754	1 754	1 473	1 452	1 678	1 684	1 670	2 603	2 590	2 502	2 502	2 502
	TR	1 174	1 174	1 174	1 174	1 174	1 048	1 048	1 048	1 048	1 048	890	890	890	890	890
	Total	12 010	12 010	12 010	12 010	12 010	6 102	6 028	4 341	4 339	4 333	-823	-825	-827	-829	-829
Net import ratio, %		21%	21%	21%	21%	21%	11%	11%	8%	8%	8%	-2%	-2%	-2%	-2%	-2%
Utilisation rates, %	Coal and lignite	18%	18%	18%	18%	18%	6%	7%	35%	35%	35%	27%	27%	27%	27%	27%
	Natural gas	46%	46%	46%	46%	46%	40%	40%	42%	42%	42%	38%	38%	38%	38%	38%
Baseload price, €/MWh		64.72	64.72	64.72	64.72	64.72	63.58	63.63	67.78	67.79	67.94	61.58	61.63	61.64	61.70	61.70
CO_2 emission (kt)		13 469	13 469	13 469	13 469	13 469	10 029	10 104	10 873	10 875	10 876	9 232	9 233	9 234	9 235	9 235

Table 34: Modelling results for Romania, Reference RES, Reference CO_2 price, Energy Efficiency

RO REF RES, REF CO_2, EE		2020					2025					2030				
		REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8	REF	REF-2	REF-4	REF-6	REF-8
Installed capacity, MW	Nuclear	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	1 413	2 113	2 113	2 113	2 113	2 113
	Coal and lignite	3 705	3 705	3 705	3 705	3 705	2 710	2 080	1 420	1 090	760	1 420	760	660	0	0
	Natural gas	2 893	2 893	2 893	2 893	2 893	3 098	3 098	3 098	3 098	3 098	3 353	3 353	3 353	3 353	3 353
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro (incl. pumped storage)	6 957	6 957	6 957	6 957	6 957	7 589	7 589	7 589	7 589	7 589	8 168	8 168	8 168	8 168	8 168
	PV	1 499	1 499	1 499	1 499	1 499	1 669	1 669	1 669	1 669	1 669	1 910	1 910	1 910	1 910	1 910
	Wind	4 403	4 403	4 403	4 403	4 403	5 535	5 535	5 535	5 535	5 535	6 814	6 814	6 814	6 814	6 814
	Biomass and other RES	250	250	250	250	250	823	823	823	823	823	1 237	1 237	1 237	1 237	1 237
Net electricity generation, GWh	Nuclear	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	10 632	15 839	15 839	15 839	15 839	15 839
	Coal and lignite	3 084	3 084	3 084	3 084	3 084	685	288	348	307	252	431	289	145	0	0
	Natural gas	10 382	10 382	10 382	10 382	10 382	17 751	17 752	17 784	17 788	17 795	15 886	15 886	15 886	15 886	15 886
	HFO/LFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Hydro	17 795	17 795	17 795	17 795	17 795	19 528	19 528	19 528	19 528	19 528	21 131	21 131	21 131	21 131	21 131
	PV	1 664	1 664	1 664	1 664	1 664	1 852	1 852	1 852	1 852	1 852	2 119	2 119	2 119	2 119	2 119
	Wind	10 042	10 042	10 042	10 042	10 042	12 622	12 622	12 622	12 622	12 622	15 539	15 539	15 539	15 539	15 539
	Biomass and other RES	552	552	552	552	552	2 235	2 235	2 235	2 235	2 235	3 372	3 372	3 372	3 372	3 372
	Total	54 149	54 149	54 149	54 149	54 149	65 304	64 909	65 001	64 964	64 916	74 317	74 175	74 031	73 886	73 886
Gross consumption, GWh		57 051	57 051	57 051	57 051	57 051	59 510	59 509	59 497	59 493	59 485	62 381	62 380	62 380	62 378	62 378
Net import, GWh	BG	2 376	2 376	2 376	2 376	2 376	-650	-582	-1 694	-1 693	-1 690	-634	-634	-649	-637	-637
	HU	-1 285	-1 285	-1 285	-1 285	-1 285	-5 551	-5 364	-5 159	-5 140	-5 123	-8 855	-8 797	-8 915	-8 714	-8 714
	MD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

	RS	221	221	221	221	221	496	625	1 448	1 464	1 480	-2 487	-2 389	-2 085	-2 128	-2 128
	UA	1 591	1 591	1 591	1 591	1 591	-89	-79	-99	-101	-98	39	25	-3	-30	-30
	Total	2 903	2 903	2 903	2 903	2 903	-5 794	-5 400	-5 505	-5 471	-5 431	-11 936	-11 795	-11 651	-11 508	-11 508
Net import ratio, %		5%	5%	5%	5%	5%	-10%	-9%	-9%	-9%	-9%	-19%	-19%	-19%	-18%	-18%
Utilisation rates, %	Coal and lignite	10%	10%	10%	10%	10%	3%	2%	3%	3%	4%	3%	4%	3%	-	-
	Natural gas	41%	41%	41%	41%	41%	65%	65%	66%	66%	66%	54%	54%	54%	54%	54%
Baseload price, €/MWh		60.12	60.12	60.12	60.12	60.12	63.31	63.39	64.06	64.25	64.66	62.66	62.71	62.73	62.82	62.82
CO_2 emission (kt)		7 367	7 367	7 367	7 367	7 367	7 360	6 843	6 934	6 886	6 825	6 248	6 078	5 939	5 762	5 762

Table 35: Consumer surplus change in the selected modelling scenarios

Consumer Surplus change (welfare change compared to REF, m€)											
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
REF-2	BG	0,0	-11,2	-56,2	-34,8	-2,2	-145,5	-152,2	-1,6	-1,0	-1,8
	GR	0,0	-8,7	-81,1	-49,5	-3,0	-200,5	-206,6	-2,1	-1,3	-2,4
	RO	0,0	-15,4	-56,5	-28,2	-5,1	-38,3	-45,7	-1,3	-6,4	-3,3
REF-4	BG	-78,5	-86,1	-65,0	-297,4	-171,2	-147,4	-153,6	-3,1	-2,5	-2,2
	GR	-51,4	-65,1	-93,5	-416,0	-235,6	-203,1	-208,5	-4,1	-3,4	-3,0
	RO	-55,1	-71,8	-71,0	-72,9	-47,4	-40,7	-53,9	-5,3	-15,3	-4,1
REF-6	BG	-83,7	-470,8	-391,8	-299,3	-171,7	-149,9	-156,1	-4,0	-3,3	-4,4
	GR	-58,3	-512,4	-555,2	-418,8	-236,3	-206,6	-212,0	-5,2	-4,4	-5,9
	RO	-63,9	-266,4	-349,6	-88,8	-60,0	-54,9	-63,6	-7,0	-18,6	-9,7
REF-8	BG	-510,8	-502,1	-429,7	-300,0	-178,2	-151,1	-157,7	-5,7	-9,8	-4,4
	GR	-565,4	-553,6	-607,2	-419,6	-244,7	-208,2	-213,9	-7,6	-13,4	-5,9
	RO	-230,3	-330,2	-406,4	-155,8	-86,5	-58,8	-66,6	-15,8	-34,7	-9,7

Table 36: Producer surplus change in the selected modelling scenarios

Producer Surplus change (welfare change compared to REF, m€)											
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
REF-2	BG	0,0	11,3	18,6	1,4	1,9	52,6	60,2	1,0	0,8	1,5
	GR	0,0	7,9	72,5	43,4	2,8	169,7	175,1	2,0	1,3	2,5
	RO	0,0	11,3	50,4	25,8	2,5	39,5	45,8	-0,4	3,0	-6,7
REF-4	BG	42,8	48,5	26,9	148,0	78,2	53,8	61,4	2,1	2,1	1,8
	GR	44,4	57,6	84,1	347,5	197,2	172,1	177,0	4,0	3,4	3,1
	RO	52,1	59,5	59,2	68,9	43,9	40,9	51,7	-0,2	7,9	-8,4
REF-6	BG	47,4	267,9	217,1	149,1	78,6	55,8	63,5	2,8	2,7	3,6
	GR	50,6	425,2	469,4	349,9	197,7	175,4	180,2	5,1	4,5	6,1
	RO	55,9	230,4	296,7	82,6	54,5	51,7	58,4	0,3	9,0	-13,1
REF-8	BG	296,8	291,6	248,4	149,6	84,0	56,7	64,8	4,2	8,2	3,6
	GR	461,6	462,9	515,8	350,6	205,0	177,0	182,1	7,5	13,7	6,1
	RO	205,1	281,3	337,2	137,4	76,0	53,8	59,8	4,3	16,3	-13,1

Table 37: Rent change in the selected modelling scenarios

Rent change (welfare change compared to REF, m€)											
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
REF-2	BG	0,0	0,0	1,9	1,6	0,0	11,7	11,6	0,1	-0,1	0,1
	GR	0,0	-0,2	1,7	1,2	0,0	13,1	12,8	0,1	-0,1	0,0
	RO	0,0	0,2	0,1	0,3	0,0	3,5	3,6	0,0	-0,1	0,0
REF-4	BG	-0,9	1,3	2,2	22,3	13,7	11,8	11,5	0,1	-0,3	0,1
	GR	-1,1	-0,2	2,0	22,3	17,3	13,1	12,8	0,0	-0,3	0,0
	RO	0,5	1,4	0,3	7,8	4,1	3,6	3,5	0,0	-0,2	0,0
REF-6	BG	-0,8	31,4	20,9	22,0	13,3	11,6	11,4	0,1	-0,4	0,1
	GR	-1,0	29,4	29,1	22,5	16,9	13,2	12,9	0,0	-0,3	0,0
	RO	0,7	26,7	23,5	8,6	4,4	3,5	3,5	0,0	-0,3	-0,1
REF-8	BG	34,1	31,8	22,0	19,9	12,9	11,6	11,5	0,0	-0,3	0,1
	GR	32,6	31,3	31,5	22,5	16,8	13,2	13,0	-0,1	-0,1	0,0
	RO	25,8	32,6	28,0	11,9	5,9	3,5	3,5	-0,1	-0,4	-0,1

Table 38: Total welfare change in the selected modelling scenarios

Total Surplus change (welfare change compared to REF, m€)											
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
REF-2	BG	0,0	0,0	-35,6	-31,8	-0,3	-81,2	-80,4	-0,6	-0,3	-0,2
	GR	0,0	-1,0	-6,9	-4,8	-0,2	-17,7	-18,7	0,0	-0,1	0,1
	RO	0,0	-4,0	-6,0	-2,0	-2,6	4,7	3,6	-1,7	-3,6	-10,0
REF-4	BG	-36,7	-36,2	-36,0	-127,1	-79,3	-81,8	-80,7	-0,9	-0,8	-0,3
	GR	-8,1	-7,7	-7,3	-46,3	-21,2	-17,8	-18,7	-0,1	-0,2	0,2
	RO	-2,5	-10,9	-11,5	3,9	0,6	3,8	1,3	-5,4	-7,6	-12,4
REF-6	BG	-37,0	-171,5	-153,8	-128,3	-79,8	-82,5	-81,3	-1,1	-1,0	-0,7
	GR	-8,7	-57,8	-56,7	-46,5	-21,6	-18,0	-18,8	-0,1	-0,3	0,2
	RO	-7,3	-9,3	-29,4	2,4	-1,1	0,2	-1,7	-6,8	-9,9	-22,8
REF-8	BG	-179,9	-178,6	-159,3	-130,4	-81,3	-82,8	-81,5	-1,6	-1,9	-0,7
	GR	-71,2	-59,3	-59,9	-46,6	-23,0	-18,1	-18,8	-0,2	0,1	0,2
	RO	0,7	-16,3	-41,1	-6,4	-4,6	-1,4	-3,4	-11,6	-18,8	-22,8

Annex 3 - Model assumptions

Table 39 Exogenous power plant investment

Country	Unit name	Installed capacity [MW]	(Expected) year of commissioning	Fuel type	Type
BG	TPP Rousse D	110	2020	coal	thermal
BG	Kozlodui VII	1,000	2027	nuclear	nuclear
BG	TPP Varna 1	420	2019	natural gas	OCGT
BG	TPP Varna 2	210	2020	natural gas	OCGT
BG	TPP Varna 3	210	2021	natural gas	OCGT
BG	TPP Varna 4	210	2023	natural gas	OCGT
BG	TPP Varna 5	210	2025	natural gas	OCGT
GR	Ptolemais V	660	2021	lignite	thermal
GR	Mytilinaios	826	2021	natural gas	CCGT
RO	NPP Cernavoda I. refurb	707	2028	nuclear	nuclear
RO	Rovinari	300	2026	natural gas	CCGT
RO	Ișalnița	300	2026	natural gas	CCGT
RO	Craiova	300	2024	natural gas	CCGT
RO	Mintia	300	2024	natural gas	CCGT
RO	Iernut	400	2020	natural gas	CCGT
RO	Cernavoda III	700	2030	nuclear	nuclear

Source: National planning documents

Table 40 EUA price assumption (EUR/t)

CO_2 price scenario	2018	2019	2020	2021	2022	2023	2024
Low	15.0	25.0	15.2	20.0	20.7	21.4	22.1
REF	15.0	25.0	30.2	35.0	35.7	36.4	37.1
High	15.0	25.0	45.2	50.0	50.7	51.4	52.1
	2025	2026	2027	2028	2029	2030	
Low	22.9	22.4	21.9	21.4	20.9	20.4	
REF	37.9	37.4	36.9	36.4	35.9	35.4	
High	52.9	52.4	51.9	51.4	50.9	50.4	

Source: own estimation based on EMEA and ICIS

Table 41 Fuel prices

Fuel		2018	2019	2020	2021	2022	2023	2024
ARA coal price, EUR/GJ		2.9	2.9	2.3	2.3	2.3	2.3	2.3
Natural gas price; EUR/MWh	BG	21.8	21.8	21.8	21.9	21.9	22.0	22.0
	GR	22.1	22.1	22.1	22.3	22.5	22.8	23.0
	RO	23.1	23.1	23.1	22.7	22.2	21.8	21.3
		2025	2026	2027	2028	2029	2030	
ARA coal price, EUR/GJ		2.3	2.3	2.3	2.3	2.3	2.3	
Natural gas price; EUR/MWh	BG	22.1	22.2	22.3	22.3	22.4	22.5	
	GR	23.2	23.3	23.3	23.4	23.4	23.5	
	RO	20.9	21.5	22.1	22.6	23.2	23.8	

Table 42 Benchmark overnight investment costs, EUR/kW

	CCS	2018	2019	2020	2021	2022	2023	2024
Thermal	no	2612	2599	2586	2573	2560	2548	2535
	yes	5640	5556	5472	5390	5309	5230	5151
OCGT	no	879	879	879	879	879	879	878
	yes	1729	1708	1688	1668	1648	1628	1608
CCGT	no	923	923	922	922	921	921	920
	yes	1800	1773	1747	1720	1695	1669	1644
	CCS	2025	2026	2027	2028	2029	2030	
Thermal	no	2522	2510	2497	2485	2472	2460	
	yes	5074	4998	4923	4849	4776	4705	
OCGT	no	878	878	878	878	878	877	
	yes	1589	1570	1551	1532	1514	1496	
CCGT	no	920	919	919	919	918	918	
	yes	1619	1595	1571	1548	1524	1502	

Source: EIA (2018)

Table 43 Electricity demand

	2018	2019	2020	2021	2022	2023	2024
BG	36181	37005	37830	38655	38962	39270	39578
GR	57774	57781	57789	57796	57804	57811	57819
RO	56205	56534	56863	59137	61410	63683	65956
RO low	57639	58491	59355	59557	59761	59965	60170
	2025	2026	2027	2028	2029	2030	
BG	39886	40193	40501	40809	41117	41424	
GR	57826	57834	57841	57849	57856	57864	
RO	68229	70503	72776	75049	77322	79595	
RO low	60375	60334	60292	60250	60209	60167	

Source: National policy documents and data provided by local partners

Table 44 Existing cross-border Net Transfer Capacities, MW

From	To	Origin → Destination	Destination → Origin
BG	GR	500	331
BG	MK	208	100
BG	RO	300	300
BG	RS	263	156
HU	RO	700	700
IT	GR	500	500
MK	GR	270	350
RS	RO	506	511
RO	UA_W	100	550
AL	GR	242	248
GR	TR	184	134
RO	MD	0	0
TR	BG	300	350

source: ENTSO-E

Table 45 New cross-border capacities

NTC, MW				
From	To	Year of commissioning	Origin → Destination	Destination → Origin
RO	RS	2018	844	600
RO	HU	2018	617	335
BG	GR	2023	1350	800
RO	HU	2030	1117	685
RS	RO	2030	347	622
GR	MK	2030	0	479

Source: ENTSO-E TYNDP 2018

Table 46: Assumed retirement paths for non-RES power plants

Country	Unit name	REF	REF-2	REF-4	REF-6	REF-8	Fuel type	Capacity (MW)
BG	TPP Maritsa East 2 A-B	2025	2023	2021	2021	2021	lignite	342
BG	TPP Maritsa East 2 C	2025	2023	2021	2021	2021	lignite	177
BG	TPP Maritsa East 2 D	2025	2023	2021	2021	2021	lignite	177
BG	Lukoil_Nefto	2040	2040	2040	2040	2040	HFO	257
BG	TPP Brikel	2021	2021	2021	2021	2021	coal	180
BG	TPP Bobov dol B	2024	2022	2021	2021	2021	lignite	210
BG	TPP Bobov dol C	2024	2022	2021	2021	2021	lignite	210
BG	TPP Deven	2039	2037	2035	2033	2031	coal	53
BG	TPP Deven	2039	2037	2035	2033	2031	coal	53
BG	TPP Rousse D	2040	2038	2036	2034	2032	coal	110
BG	TPP Rousse E	2040	2038	2036	2034	2032	coal	60
BG	TPP Rousse F	2040	2038	2036	2034	2032	coal	60
BG	TPP Maritsa East 2 E-F	2025	2023	2021	2021	2021	lignite	442
BG	TPP Maritsa East 2 G-H	2025	2023	2021	2021	2021	lignite	464
BG	NPP Kozloduy E	2047	2045	2043	2041	2039	nuclear	1000
BG	NPP Kozloduy F	2049	2047	2045	2043	2041	nuclear	1000
BG	TPP Gabrovo	2055	2055	2055	2055	2055	coal	18
BG	Kozlodui VII	2087	2087	2087	2087	2087	nuclear	1000
BG	CHP TPP Pernik	2021	2021	2021	2021	2021	coal	130
BG	CHP TPP Sliven	2021	2021	2021	2021	2021	lignite	30
BG	CHP TPP Vladislav Varnenchik	2029	2027	2025	2023	2021	coal	11
BG	AES Galobovo 1	2028	2026	2024	2022	2021	lignite	335
BG	AES Galobovo 2	2028	2026	2024	2022	2021	lignite	335
BG	Maritsa Iztok 3 unit 1	2028	2026	2024	2022	2021	lignite	227
BG	Maritsa Iztok 3 unit 2	2028	2026	2024	2022	2021	lignite	227
BG	Maritsa Iztok 3 unit 3	2028	2026	2024	2022	2021	lignite	227
BG	Maritsa Iztok 3 unit 4	2028	2026	2024	2022	2021	lignite	227
BG	Maritsa 3	2021	2021	2021	2021	2021	lignite	120

BG	TPP Shouumen	2021	2021	2021	2021	2021	natural gas	18
BG	TPP Plovdiv B	2041	2041	2041	2041	2041	natural gas	30
BG	TPP Plovdiv A	2025	2025	2025	2025	2025	natural gas	105
BG	TPP Pleven	2047	2047	2047	2047	2047	natural gas	36
BG	CHP TPP Sofia	2043	2043	2043	2043	2043	natural gas	40
BG	CHP TPP Sofia-Istok	2043	2043	2043	2043	2043	natural gas	156
BG	CHP Ovcha Kupel 2	2047	2047	2047	2047	2047	natural gas	12
BG	CHP Zemlyame 1	2046	2046	2046	2046	2046	natural gas	45
BG	TPP Varna 1	2050	2050	2050	2050	2050	natural gas	420
BG	TPP Varna 2	2050	2050	2050	2050	2050	natural gas	210
BG	TPP Varna 3	2050	2050	2050	2050	2050	natural gas	210
BG	TPP Varna 4	2050	2050	2050	2050	2050	natural gas	210
BG	TPP Varna 5	2050	2050	2050	2050	2050	natural gas	210
GR	Kardia I	2019	2019	2019	2019	2019	lignite	300
GR	Kardia II	2019	2019	2019	2019	2019	lignite	300
GR	Megalopolis III	2019	2019	2019	2019	2019	lignite	300
GR	Kardia III	2020	2020	2020	2020	2020	lignite	306
GR	Kardia IV	2020	2020	2020	2020	2020	lignite	306
GR	Agios Dimitrios I	2028	2026	2024	2022	2021	lignite	300
GR	Agios Dimitrios II	2028	2026	2024	2022	2021	lignite	300
GR	Agios Dimitrios III	2028	2026	2024	2022	2021	lignite	310
GR	Agios Dimitrios IV	2028	2026	2024	2022	2021	lignite	310
GR	Amyntaio I	2022	2021	2021	2021	2021	lignite	300
GR	Amyntaio II	2022	2021	2021	2021	2021	lignite	300
GR	Megalopolis IV	2028	2026	2024	2022	2021	lignite	300
GR	Lavrio IV	2034	2034	2034	2034	2034	natural gas	560
GR	Agios Dimitrios V	2028	2026	2024	2022	2021	lignite	375
GR	Komotini	2037	2037	2037	2037	2037	natural gas	484.6
GR	Heron 1, Thiva	2041	2041	2041	2041	2041	natural gas	148.5
GR	Lavrio V	2041	2041	2041	2041	2041	natural gas	385.2
GR	Thessaloniki	2036	2036	2036	2036	2036	natural gas	408.5

GR	Melitis	2028	2026	2024	2022	2021	lignite	330
GR	Aliminium	2040	2040	2040	2040	2040	natural gas	334
GR	Protergia_CC	2039	2039	2039	2039	2039	natural gas	444.5
GR	KORINTHOS_POWER	2040	2040	2040	2040	2040	natural gas	436.6
GR	Heron II	2041	2041	2041	2041	2041	natural gas	432
GR	Aliveri V	2043	2043	2043	2043	2043	natural gas	426.9
GR	Elpedison	2041	2041	2041	2041	2041	natural gas	421.6
GR	Megalopolis V.	2046	2046	2046	2046	2046	natural gas	845
GR	Piso Kampos Rhodes	2047	2047	2047	2047	2047	LFO	0
GR	Ptolemais V	2050	2050	2050	2050	2050	lignite	660
GR	Crete	2023	2023	2023	2023	2023	HFO	164.1
GR	Crete	2023	2023	2023	2023	2023	HFO	164.1
GR	Crete	2023	2023	2023	2023	2023	HFO	164.1
GR	Crete	2023	2023	2023	2023	2023	HFO	164.1
GR	Crete	2023	2023	2023	2023	2023	HFO	164.1
GR	Rodos	2027	2027	2027	2027	2027	LFO	347
GR	Other islands	2029	2029	2029	2029	2029	LFO	284
GR	Other islands	2029	2029	2029	2029	2029	LFO	284
GR	Mytilinaios	2050	2050	2050	2050	2050	natural gas	826
GR	Other small PPs	2030	2030	2030	2030	2030	natural gas	250
RO	TPP Iernut 1 (Mures)	2020	2020	2020	2020	2020	natural gas	100
RO	TPP Iernut 4 (Mures)	2020	2020	2020	2020	2020	natural gas	100
RO	TPP Iernut 5 (Mures)	2020	2020	2020	2020	2020	natural gas	200
RO	TPP Iernut 6 (Mures)	2020	2020	2020	2020	2020	natural gas	200
RO	Bucaresti Sud CHP 3-4	2021	2021	2021	2021	2021	natural gas	195
RO	TPP Isalnita 7	2026	2024	2022	2021	2021	lignite	315
RO	TPP Isalnita 8	2026	2024	2022	2021	2021	lignite	315
RO	CHP Galati 3	2020	2020	2020	2020	2020	natural gas	105
RO	TPP Mintia 3	2024	2022	2022	2022	2022	coal	235
RO	TPP Rovinari III.	2031	2029	2027	2025	2023	lignite	330
RO	TPP Mintia 6	2024	2022	2022	2022	2022	coal	210

RO	TPP Rovinari IV.	2036	2034	2032	2030	2028	lignite	330
RO	TPP Rovinari VI.	2036	2034	2032	2030	2028	lignite	330
RO	TPP Turceni 3	2028	2026	2024	2022	2021	lignite	330
RO	TPP Turceni 4	2029	2027	2025	2023	2021	lignite	330
RO	TPP Turceni 5	2032	2030	2028	2026	2024	lignite	330
RO	CHP Iasi II. A	2034	2032	2030	2028	2026	coal	100
RO	CHP Govora 3.	2021	2021	2021	2021	2021	coal	50
RO	CHP Govora 4	2021	2021	2021	2021	2021	coal	50
RO	TPP Craiova I.	2024	2022	2021	2021	2021	lignite	150
RO	TPP Craiova II.	2024	2022	2021	2021	2021	lignite	150
RO	NPP Cernavoda I.	2026	2026	2026	2026	2026	nuclear	706.5
RO	NPP Cernavoda I. refurb	2056	2056	2056	2056	2056	nuclear	706.5
RO	NPP Cernavoda II.	2067	2067	2067	2067	2067	nuclear	706.5
RO	Cet Vest 3	2050	2050	2050	2050	2050	natural gas	195
RO	PAROSENI 4	2024	2022	2022	2022	2022	coal	150
RO	Arad	2027	2027	2027	2027	2027	natural gas	60
RO	Brazi	2051	2051	2051	2051	2051	natural gas	894
RO	Grozavesti	2023	2023	2023	2023	2023	natural gas	100
RO	92 small new TPPs	2050	2050	2050	2050	2050	natural gas	614
RO	TPP Brazi 5-6	2028	2028	2028	2028	2028	natural gas	210
RO	CET Progresu	2023	2023	2023	2023	2023	natural gas	100
RO	7 small old TPPs	2030	2030	2030	2030	2030	natural gas	75
RO	CHP Oradea	2041	2041	2041	2041	2041	natural gas	50
RO	Rovinari	2050	2050	2050	2050	2050	natural gas	300
RO	Ișalnița	2050	2050	2050	2050	2050	natural gas	300
RO	Craiova	2050	2050	2050	2050	2050	natural gas	300
RO	Mintia	2050	2050	2050	2050	2050	natural gas	300
RO	Iernut	2050	2050	2050	2050	2050	natural gas	400
RO	Cernavoda IV	2068	2068	2068	2068	2068	nuclear	700
RO	Cernavoda III	2068	2068	2068	2068	2068	nuclear	700

source: REKK database adjusted based on data received from EPG, CSD and FACETS