Decarbonisation modelling in the electricity sector

Serbia

Support for Low-Emission Development in South Eastern Europe (SLED)
Decarbonisation modelling in the electricity sector

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AUTHORS
András Mezősi
László Szabó
Slobodan Markovic

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The REC is implementing the project “Support for Low-Emission Development in South Eastern Europe” (SLED) to help policy makers in the project countries (Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia) to establish realistic but ambitious decarbonisation pathways for their electricity and building sectors by 2030.

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References to Kosovo* in this publication should be understood according to the following definition: This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence.
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I. Executive summary
The objective of the project “Support for Low-Emission Development in South Eastern Europe (SLED)” is to help policy makers in Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia to set realistic but ambitious decarbonisation pathways for their electricity sectors up to 2030.

This study assesses the effect of decarbonisation scenarios on the Serbian electricity system. In the current assessment we also include Kosovo*, meaning that data referring to Serbia include Kosovo*, unless indicated otherwise.

The scenarios (Reference – REF; Currently Planned Policies – CPP; and Ambitious – AMB) use different assumptions related to electricity demand and supply. Supply-side factors include the deployment levels of renewable energy sources for electricity (RES-E), conventional capacity expansion levels and the applied energy and carbon taxation rates. On the demand side, the various scenarios assume different electricity consumption based on the effectiveness of energy efficiency policies.

The scenarios and assumptions were agreed with the main stakeholders in Serbia (the Ministry of Mining and Energy, the Ministry for Agriculture and Environmental Protection, the Environmental Protection Agency, and electricity experts).

The assessment was carried out using the European Electricity Market Model (EEMM) developed by the Regional Centre for Energy Policy Research (REKK) and the network model of the Electricity Coordinating Center (EKC). The EEMM is a detailed, bottom-up economic simulation model covering the whole European Network of Transmission System Operators for Electricity (ENTSO-E) region, while the EKC network model covers the medium- and high-voltage network of the South East European (SEE) region.

The following main conclusions could be drawn from the scenario modelling:

- The stringency of climate policy commitments has limited impact on wholesale price development. The wholesale price is dependent on regional generational capacity expansion rather than on the ambition level of climate policy. Since, at regional level, significant capacity expansion is foreseen in the coming five years in both fossil- and renewable-based generation, it will drive wholesale electricity prices down in the whole SEE region until 2025.

- The generation mix in the scenarios is shaped primarily by the various planned new fossil capacity levels. The REF scenario assumes six new power plants with total additional capacities of 2,885 MW, while the CPP and AMB scenarios include a more modest capacity increase in conventional generation (1,860 MW and 630 MW respectively). The lower fossil-based generation is substituted by hydro in the AMB scenario in the longer term (by 2030).

- Serbia is almost self-sufficient in 2015 in terms of electricity consumption, although more new fossil capacities will facilitate more export possibilities. Serbia remains a net exporter from 2020 onwards. Only the AMB scenario indicates a minor need for imports in 2030.

- The stepwise reduction in new conventional capacity between the scenarios is translated into a similar pattern in terms of CO₂ emissions, with significant differences between the scenarios. Per capita CO₂ emissions in Serbia are at least double the ENTSO-E average in all scenarios and reference years, due to the dominance of fossil-based generation, which, although different in the three scenarios (due to the new capacity assumptions), nevertheless remains significant compared to renewables, with the exception of the AMB scenario in 2030. The indicator for the CO₂ intensity of electricity production shows a similar pattern: higher but decreasing Serbian figures compared to the ENTSO-E average. The increase in the CO₂ indicator for electricity consumption reflects the fact that Serbia becomes an electricity exporter in 2020.

- Due to the stepwise introduction of the Emissions Trading System (ETS) carbon price, the revenue stream shows an increasing trend, reaching EUR 600 to EUR 900 million by 2030. The differences between the scenarios are due to the different volumes of the assumed new conventional capacities. The average RES-E charge on consumed electricity peaks in the REF scenario in 2020 (EUR 7.8/MWh). Although considerable, this charge is lower than the 2012 support level in many European member states. According to a 2015 report by the Council of European Energy Regulators (CEER) on EU renewable support schemes, EU member states supported RES-E with an average of EUR 13.68/MWh in 2012. Government tax revenues collected on energy use (carbon and energy tax) can easily finance the required RES-E support budget after 2020.
The REF scenario results in higher cumulated investment costs compared to the — quite similar — CPP and AMB scenarios. This means that the additional cost of more hydro, wind and biomass production units is still lower than the cost of the coal plants assumed in the REF scenario, but not in the AMB scenario and only partly in the CPP scenario.

The security of supply concern is further analysed in order to check the impact of a dry year on the Serbian electricity system. In the short term, severe droughts — modelled as the driest of the past eight years in the region — could drive up prices by EUR 7.5/MWh, and in the long term by EUR 3 to EUR 4/MWh. In 2015, reduced hydro generation is fully substituted by an increase in imports. In 2020, the cutback in hydro leads to a reduction in imports in the REF and CPP scenarios. However, due to self-sufficient production, it leads to an increase in fossil-based generation in the AMB scenario. In 2030, Serbia is able to increase its exports in the region due to a large drop in hydro generation in neighbouring countries.

The overall conclusion of the sensitivity assessment is that Serbia, with its ambitious fossil capacity plans and relatively modest hydro generation share, will be able to expand its electricity exports in dry years due to the greater vulnerability of the other countries in the region.

The assessment of network impacts shows that, in general, the Serbian electricity system would require some reinforcements in its network in order to cope with the planned RES capacity increase in the scenarios. If the planned network additions are built, no further contingencies would appear in the system. The change in net transfer capacities (NTC) does not show a distinct pattern across borders or in the various regimes (2020/2025 and winter/summer). The increase in RES-E in terms of overall installed capacities will produce lower transmission losses in gross consumption in Serbia in both 2020 and 2025 compared to the REF scenario.

Executive summary Figure 1 Generation mix, net imports and CO₂ emissions in the three scenarios
Executive summary Figure 2: Tax-based revenues and expenditure on support for renewable energy sources for electricity.
II. Introduction
The main objective of the SLED project is to help policy makers in Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia in setting up realistic but ambitious decarbonisation pathways for their electricity sectors up to 2030. Policy developments should be evidence based, as far as possible building on quantified modelling results obtained from the possible set of future decarbonisation scenarios. The SLED project assisted the countries with modelling, accompanied by a continuous consultation process to enable national policy makers to influence the scenario development process according to their needs for their future energy sector and climate strategy developments. During the modelling exercise, policy options related to production levels and/or the fuel mix for electricity generation — such as supply-side energy efficiency improvements, the accelerated retirement of old power plants, increasing shares of renewable energy sources (RES), and electricity demand — were assessed from the perspective of CO₂ emissions, generation capacity investment costs and renewable support needs.
III. Methodology
In this section we introduce the framework for the scenarios, including the differentiation dimension, and the two models used in the assessment of the scenarios.

**Scenario development framework**

In order to assess the full range of the decarbonisation potential in the assessed countries, three scenarios were constructed for each country in the SLED project: Reference (REF); Currently Planned Policies (CPP); and Ambitious (AMB). Scenario assumptions were related to six dimensions:

- carbon value;
- energy/excise tax;
- environmental standards;
- deployment of renewable energy technologies;
- deployment of conventional generation technologies; and
- electricity demand (integrating assumptions on end-use energy efficiency improvement).

The above factors all affect national CO$_2$ emissions either via the level of electricity production or by their impact on the fuel mix for electricity generation. As far as taxation is concerned, two factors are identified. First, the introduction of the EU ETS either as a consequence of EU membership or the transposition of EU law required for members of the Energy Community; and second, simply the introduction of a national policy instrument placing value on carbon emissions, which alters the cost of respective generation technologies and hence the production possibilities. The same logic applies to the introduction of the minimum tax level on energy products required by EU legislation. The electricity supply mix is affected by the introduction of European air pollution regulations: the Large Combustion Plants (LCP) Directive, for example, may force the most polluting coal plants out of operation, or limit their operating hours. The development of renewables and conventional (fossil) generation capacities is the outcome of national policy decisions and — in the case of renewables — support levels. Electricity demand growth triggers higher production from the available power plant portfolio or imports.

The REF scenario reflects the business-as-usual developments in the country, meaning that the official energy policy and legislative instruments that were in place by the closing date of the scenario definition (July 2015) are included. The CPP scenario reflects those policies that are under consideration and that could have an impact on GHG emissions. The third scenario, AMB, represents the most advanced climate policy stand.

The options included in the scenarios are assessed not only for the individual countries but also in terms of possible synergies from more collaborative actions among SEE countries. Modelling the various options listed above can help to identify the most effective options to reduce CO$_2$ emissions in the assessed countries. Other impacts, such as those relating to security of supply and network reliability, are also included in the analysis.

**CONDITIONS SPECIFIC TO SERBIA**

The main data and policy inputs for the scenarios were agreed with relevant stakeholders (the Ministry of Energy and Mining, the Ministry of Agriculture and Environmental Protection, and the Environmental Protection Agency) at a meeting held in Belgrade in November 2014. In the current assessment we include Kosovo*, meaning that data referring to Serbia include Kosovo*, unless indicated otherwise.

**Models**

Decarbonisation scenarios for the four assessed countries and the region as a whole were developed using the state-of-the-art European Electricity Market Model (EEMM) in tandem with the detailed technical network model of the Electricity Coordinating Center (EKC). The EEMM has been frequently applied in the region in the past in relation to Projects of Energy Community Interest (PECI) assessment, while the network model has been used in many network expansion and upgrade projects in the region. The EEMM is a partial equilibrium model focused on generation capacities, while the EKC network model focuses on the transmission system, in particular on the development of cross-border capacities. The two models are introduced briefly in this section: more detailed model descriptions can be found in the Annex.

The reliability of model results was ensured by working closely together with stakeholders in the region. The EKC network modelling team is from Serbia, which means that the modelling experts have in-depth regional knowledge. In addition to this insider involvement, three project factors gave unique added value to the assessment:
The models were updated with the most recent data from the beneficiary countries, with the help of local experts.

Throughout the project, the involvement of stakeholders — including representatives of relevant ministries dealing with climate- and energy-related issues and representatives of the transmission system operators (TSOs) — was ensured by setting up a project “task force”. These experts and policy makers were involved in defining policy-relevant scenarios and in the assessment of model results already at an early stage of the project. They also provided up-to-date information on national energy policies and checked the validity of information and data at the stakeholder meeting in November 2014.

The dissemination of project results is ensured by means of workshops in all participating countries.

The relevant experts and stakeholders in the project countries were reached with the help of a local expert consultancy (EKC from Serbia), as well as the local offices of the Regional Environmental Center (REC), which has long-term expertise and a solid network in the region.

The European Electricity Market Model

The EEMM is a simulation model of the European electricity wholesale market that works in a stylised manner with perfect competition assumptions.

The EEMM covers 36 countries with rich bottom-up representation. In Figure 1, in the countries coloured orange, electricity prices are derived from the demand-supply balance, and in the blue countries prices are exogenous. The ENTSO-E countries of the EU (Malta and Cyprus are not included in the model) and Balkan countries are modelled in full detail.

In the electricity production sector we have differentiated 12 technologies. We assume one interconnector per pair of countries, which means modelling 85 transmission lines. The EEMM models the production side at unit level, which means that at the greater European level almost 5,000 units are included in the model runs. Equilibrium (in prices and quantities) is reached simultaneously in the producer and the transmission segments. These units are characterised by various technological factors, allowing the construction of the merit order for the particular time period. In each year we have 90 reference hours to represent the load curve with sufficient detail for each European country.

There are three types of market participants in the model: producers, consumers and traders. All of them behave in a price-taking manner: they take the prevailing market price as given, and assume that whatever action they decide upon has a negligible effect on this price.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation is capacity constrained at the level of available capacity.

The model only takes into account short-term variable costs with the following three main components: fuel costs, variable operational expenditure (OPEX), and CO₂ costs (where applicable). As a result, the approach is best viewed as a simulation of short-term (e.g. day-ahead) market competition.

Price-taking producer behaviour implies that whenever the market price is above the marginal generation cost of a unit, the unit is operated at full available capacity. If the price is below the marginal cost, there is no production at all; and if the marginal cost and the market price coincide, then the level of production is determined by the market clearing condition (supply must equal demand).

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. In each demand period there is an inverse relationship between the market price and the quantity consumed: the higher the price, the lower the consumption. This relationship is approximated by a downward sloping linear function.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Cross-border trade takes place on capacity-constrained interconnectors between neighbouring countries. Electricity exchanges always occur from a less expensive country to a more expensive one, until one of two things happens: either prices, net of direct transmission costs or export tariffs, equalise across the two markets; or the transmission capacity of the interconnector is reached. In the second case, a considerable price difference may remain between the two markets.

The model calculates the simultaneous equilibrium allocation in all markets with the following properties:
Producers maximise their short-term profits given the prevailing market prices.

Total domestic consumption is given by the aggregate electricity demand function in each country.

Electricity transactions (exports and imports) occur between neighbouring countries until market prices are equalised or transmission capacity is exhausted.

Energy produced and imported is in balance with energy consumed and exported.

Given our assumptions about demand and supply, market equilibrium always exists and is unique in the model.

The EKC network model

Electric power systems in SEE are modelled with their complete transmission networks at 400 kV, 220 kV and 150 kV. The power systems of Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia are also modelled at the 110 kV voltage level. The network equivalent of Turkey (i.e. European part) and the rest of ENTSO-E Continental Europe (modelled over the X-node injections) are used in the model.

The network model in this assessment provides the following results:

• Contingency analyses, which include:
  • an assessment of the existing electricity network situation within Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, together with the regional context; and
  • a definition of the network topologies and regimes for 2015, 2020 and 2025, using realistic scenarios for demand growth, generation expansion, transit flows, RES integration and high-voltage direct current (HVDC) links.

• Total and net transfer capacity (TTC/NTC) evaluation between Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia in all directions, for all topology scenarios.

• An assessment of transmission grid losses with and without a level of energy production from RES.

STEADY-STATE AND CONTINGENCY ANALYSES

For the defined scenarios, steady-state load flows are calculated and contingency (n-1) analyses performed.
Security criteria are based on the loadings of lines and voltage profile and are checked for each scenario analysed.

Load-flow assessment is a basic step for NTC evaluation, and it comprises the following analyses:

- steady-state AC load-flow analysis;
- a security (n-1) assessment where the tripping of lines is simulated. This means that one line is considered out of service while load flow is calculated and the security of the system assessed (circuit overloads and voltage violations); and
- a voltage profile analysis.

In the analysis of voltage profiles, voltage limits are according to the respective national grid codes.

EVALUATION OF NET TRANSFER CAPACITY

Total and net transfer capacity (TTC/NTC) were evaluated between Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, as well as between these countries and their neighbours, in all directions and for all topology scenarios, with reference to each target year and regime, and a final assessment was made of the TTC/NTC additional values as a result of the new interconnections and the strengthening of the major internal energy transit routes.

General definitions of transfer capacities (TTC and NTC) and the procedures for their assessment were given by ENTSO-E, as well as by the practice and experience of regional SEE TSO working groups.

The methodology used in performing this study was based on the prerequisites outlined below.

The assessment of electricity losses is based on losses over the equivalent time duration in the winter peak and summer peak periods. This approach takes into account that the effect on losses may be different in these two regimes, as a result of which losses on a yearly level can be determined more accurately.

Cross-border network capacities

Even though countries in the SEE region are well connected with their neighbours, further capacity extensions are envisaged in the future. The model uses the NTC values of ENTSO-E to reflect the trading possibilities between countries. Tables 1 and 2 show the present NTC values in the region, including neighbouring countries, and the planned new connections in the modelling timeframe.

The Montenegro–Italy 1,000 MW submarine cable is planned to start operation in 2018. Construction has already started and is proceeding according to the investment plan. The other submarine cable connecting Italy with Albania is very uncertain and might not be realised as planned, or might even be cancelled. The modelling considers the “approved” and “under construction” categories of ENTSO-E in all three scenarios.

Current generation capacities

Table 3 provides information on electricity generation capacities for the base year, 2014. There were no wind capacities installed in Serbia in 2014.

Fossil fuel prices

Table 4 shows the fossil fuel prices applied in the modelling for the period 2015–2030.

European Union Emissions Trading System price

Concerning the carbon price assumptions, we followed the carbon value path of the latest EU impact assessment (GHG40EE scenario) and assumed an ETS carbon price of EUR 22/tCO\(_2\) for Europe by 2030. The ETS price goes linearly from its 2014 value of EUR 6/t to EUR 22/t by 2030 in all scenarios.

European Union minimum tax levels for energy products

Excise duty is differentiated according to the fuel used (coal, natural gas and heavy fuel oil [HFO]). The minimum excise duty level applied is equal to the 2014 level applicable by EU law:

- EUR 0.3/GJ for natural gas;
- EUR 0.15/GJ for coal; and
- EUR 0.38/GJ for HFO.

Model assumptions

In this section we introduce those assumptions that remain constant across the various scenarios for all the assessed countries and the regional assessment as well.
### Table 1: Present net transfer capacity values in the region (MW)

<table>
<thead>
<tr>
<th>Origin and destination country</th>
<th>NTC value</th>
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<tbody>
<tr>
<td>From To</td>
<td>O–D</td>
</tr>
<tr>
<td>AL MK</td>
<td>0</td>
</tr>
<tr>
<td>BA RS</td>
<td>488</td>
</tr>
<tr>
<td>BA ME</td>
<td>483</td>
</tr>
<tr>
<td>GR MK</td>
<td>329</td>
</tr>
<tr>
<td>GR AL</td>
<td>250</td>
</tr>
<tr>
<td>HR RS</td>
<td>507</td>
</tr>
<tr>
<td>HU RS</td>
<td>689</td>
</tr>
<tr>
<td>ME AL</td>
<td>400</td>
</tr>
<tr>
<td>MK BG</td>
<td>96</td>
</tr>
<tr>
<td>RO RS</td>
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</tr>
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<td>RS MK</td>
<td>491</td>
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<tr>
<td>RS AL</td>
<td>223</td>
</tr>
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<td>RS BG</td>
<td>162</td>
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Source: ENTSO-E

### Table 2: Planned interconnectors and their investment status (MW)

<table>
<thead>
<tr>
<th>Country 1</th>
<th>Country 2</th>
<th>Year of commissioning</th>
<th>Investment status</th>
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<th>D–O</th>
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<tr>
<td>RS</td>
<td>RO</td>
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<td>Approved</td>
<td>800</td>
<td>800</td>
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<tr>
<td>BA</td>
<td>ME</td>
<td>2023</td>
<td>Planned</td>
<td>600</td>
<td>600</td>
</tr>
<tr>
<td>IT</td>
<td>AL</td>
<td>2020</td>
<td>Planned</td>
<td>500</td>
<td>500</td>
</tr>
<tr>
<td>RS</td>
<td>MK</td>
<td>2015</td>
<td>Under construction</td>
<td>400</td>
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<tr>
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<td>Planned</td>
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<tr>
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<td>ME</td>
<td>2022</td>
<td>Planned</td>
<td>600</td>
<td>600</td>
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</tbody>
</table>

Source: ENTSO-E
Table 3 Electricity generation capacities, 2014

<table>
<thead>
<tr>
<th></th>
<th>Coal and lignite</th>
<th>Natural gas</th>
<th>HFO/LFO</th>
<th>Hydro</th>
<th>Wind</th>
<th>Biomass</th>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>1,801</td>
<td>0</td>
<td>5</td>
<td>2</td>
<td>1,807</td>
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Source: REKK and PLATTS database
* By the end of 2015, wind capacity of 300 MW is planned in the NREAP

Table 4 Fuel prices, 2015–2030

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Source: IEA and EIA projections

NOTES

1. See the regional assessment.
2. In the network assessment of the 400 kV line between Montenegro, Serbia and Bosnia and Herzegovina, for example.
IV. Scenario assumptions
Table 5 summarises the scenario assumptions grouped under taxation, supply-side measures and demand-side measures.

These assumptions are based on the energy strategy documents of Serbia and Kosovo*, together with the outcomes of the stakeholder meeting held in Belgrade in December 2014. The energy policy documents used were:

- The National Renewable Energy Action Plan of Serbia and Kosovo*; and
- The Energy Strategy of Serbia, 2015 (not yet accepted).

<table>
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<th>Table 5 Main scenario assumptions for Serbia</th>
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<td><strong>Scenario assumptions</strong></td>
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<tr>
<td>Electricity demand</td>
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Introduction of the European Union Emissions Trading System

We used different assumptions with respect to Serbia joining the EU ETS. In the REF scenario, Serbia joins the ETS in 2025, while in the CPP scenario the power sector already faces a carbon value equal to 40 percent of the EU ETS price in 2020. In the AMB scenario, the Serbian power sector joins the ETS already in 2020. “Joining the ETS” does not necessarily imply EU membership: we only assume that national policy makers will apply some instruments with similar effects on the electricity sector as the EU ETS (e.g. by a voluntary or legal obligation, through a national commitment or Energy Community commitments).

Introduction of minimum excise duty on energy products

Concerning other taxes in the energy sector, we used the assumption that the country introduces the minimum level of excise duties in 2020 in the REF and CPP scenarios, while in the AMB scenario it is already introduced in 2018.

Environmental standards enforcement

Thermal power plants with a capacity below 300 MW are on average 45 years old and operate at 30 percent efficiency. The Energy Strategy envisages the gradual withdrawal of these lignite units. The power plants that are assumed to be closed in the modelling in the period between 2016 and 2025 are as follows (with installed capacity and expected year of decommissioning in brackets):

- Kolubara A1 (27 MW, 2024)
- Kolubara A2 (27 MW, 2024)
- Kolubara A3 (59 MW, 2016)
- Kodovo A1 (65 MW, 2018)
- Kosovo* A2 (125 MW, 2019)
- Kostolac A1 (100 MW, 2024)
- Morava (105 MW, 2024)
- Nikola Tesla A1 (210 MW, 2024)
- Nikola Tesla A2 (210 MW, 2025)
- Kosovo* A3 (50 MW, 2020)
- Kosovo* A4 (100 MW, 2021)

Deployment of renewable energy sources for electricity

Serbia (with Kosovo*) finalised its NREAP for the Energy Community Secretariat in 2013. The document is the basis for our modelling, providing planned capacity values up to 2020. Figures beyond 2020 are based on expert assumptions up to 2030 (Table 6).

Up until 2020, all scenarios use the NREAP numbers. From 2020 onwards, the REF scenario assumes the moderate expansion of hydro and wind capacities. The AMB scenario allows for a strong growth of hydro (2,000 MW newly installed) and the doubling of wind capacities. The CPP scenario uses the average of the REF and AMB scenario values in the respective years (2025 and 2030). These scenarios assume normal utilisation conditions for weather-dependent technologies (solar, wind), meaning average working hours and efficiency. Concerning hydro generation in these scenarios, average hydrological conditions are assumed. This assumption will be relaxed in the sensitivity assessment, where a low precipitation pattern is also assessed. The EEMM treats RES-E capacities in a “must run” operation mode to reflect the priority dispatch of renewable technologies.

Conventional power plants

Serbia plans to put into operation the following fossil-based power plants in the indicated year:

- CHP Novi Sad (440 MW), 2016, natural gas (biomass firing is also proposed)
- CHP Pancove (190 MW), 2016, natural gas
- Kolubara B (630 MW), 2019, lignite
- Kosova e Re Power (600 MW), 2020, lignite
- Kostolac B3 (320 MW), 2025, lignite
- Nikola Tesla B3 (675 MW), 2020, lignite

The construction of CHP Novi Sad (440 MW) and CHP Pancove (190 MW) is foreseen in all scenarios.
Table 6 Capacity deployment of renewable energy sources for electricity in the scenarios (MW)

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*Excluding pumped storage
The construction of the Kolubara B (630 MW) and Kosova e Re Power (600 MW) lignite power plants is assumed only in the REF and CPP scenarios, while the construction of the Kostolac B3 (320 MW) and Nikola Tesla B3 (675 MW) plants is assumed in the REF scenario exclusively.

**Electricity demand**

Electricity consumption usually closely follows a country’s GDP development. We did not prepare our own forecast based on GDP assumptions, but used a modification of the REF and energy efficiency scenarios of the Energy Strategy of Serbia (which excludes Kosovo*) in order to include Kosovo* in the electricity demand used in the modelling (Table 7).

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Table 7 Gross electricity consumption in Serbia (GWh)
V. Modelling results
In this section we discuss the results of the modelling related to wholesale price development, the electricity generation mix, CO\textsubscript{2} emissions, renewable support and investment needs for the generation capacities included in the respective scenarios.

**Price development**

One of the most important indicators of the functioning of an electricity market is the development of the wholesale price. Sudden and significant price changes are a sign of the malfunctioning of the electricity market, as they generally indicate shortages of certain generation capacities or problems with cross-border trade. As Serbia possesses hydro capacities, a change in precipitation patterns can also change the price pattern in the electricity sector. This issue is addressed in Section VI (Sensitivity assessment).

Figure 2 shows the base-load price development in Serbia in the various scenarios. The figure shows the annual base-load price development as the calculated average of the modelled base-load hours of the year. In this way it is possible to smooth out the cyclical behaviour of electricity prices over a year in order to illustrate the main trends.

One of the most important things shown by the figure is the minor differences between the scenarios. While there is a big fluctuation in terms of price between the years, there is no significant variation between the scenarios. This shows that, from the point of view of wholesale price, the assumed more ambitious GHG policies are feasible in the Serbian electricity system, thus the power system (together with import possibilities) would be able to cope with the stronger climate commitment without any significant price increase. The impacts on electricity imports and on the RES support budget will be analysed later in the present study. What can be observed as a general trend in the projection is a falling base-load price level in the coming five years, followed by a slightly increasing trend up to 2030. The reason for the significant price drop in the near future is the dynamically growing capacity pool in the region, which is analysed below under “Regional outlook”.

![Figure 2 Base-load price evolution in the various scenarios (EUR/MWh)](image-url)
Another interesting trend is the merging of the peak-load prices and base-load prices by 2030. Serbia’s increasing connectivity (in the direction of Romania, the former Yugoslav Republic of Macedonia and Albania) and more available capacities make shortages on the supply side less frequent, which, in turn, results in the convergence of base and peak prices, as illustrated in Figure 3. The same conclusion holds for the peak-load prices as for the base-load prices: the scenarios do not cause any significant differences in the wholesale market prices.

**Regional outlook**

The plummeting price trend in the first five years requires a more detailed explanation. The main driving force behind this development is the dynamic capacity expansion in the region. As the country is well connected with its neighbours, any increase in generation capacities in the neighbouring countries will also increase supply in Serbia, thus reducing prices in the whole region. As illustrated in Figures 4 and 5, there is a significant peak in the construction of new power plants in the region in the period 2015-2020. As Figures 4 and 5 show, most of the new fossil-based generation is due to be built in the coming five years, meaning a significant and quite rapid increase on the generation side. This increase in generation is complemented by an even more sizeable increase in renewable capacities, mainly wind and hydro. All these new plants represent a significant pressure on the supply side, and, if realised, could lead to significant price reductions in the coming years. As many of these plants are under construction or have a final investment decision (FID), they will probably be built even in an environment of falling electricity prices. Under these investment conditions, project developers are trying to finalise their projects as soon as possible, as new entrants will deter other investors from entering the market. However, this might lead to a situation in which all new entrants lose money, as the falling price trend would undermine the long-term profitability of the fossil fuel–based plants (mainly coal-based generation), especially if accompanied by an increasing carbon price trend.

![Figure 3 Peak-load price evolution in the various scenarios (EUR/MWh)](image)
Figure 4 Planned new fossil fuel–based capacities in South Eastern Europe, 2015–2030

Source: EEMM database, Platts

Figure 5 Planned new renewable-based capacities in South Eastern Europe, 2015–2030

Source: EEMM database, Platts
Generation mix

While we can observe less pronounced changes in the wholesale electricity prices, the various policies have profound impacts on the electricity generation mix, on the export-import position of the country, and thus on CO₂ emissions. Figure 6 summarises the above-mentioned impacts of the three assessed scenarios.

The generation mix in the scenarios is shaped primarily by the different planned new fossil capacity levels. The REF scenario assumes six new power plants with a total of 2,885 MW of additional capacity, while the CPP and AMB scenarios include a more modest capacity increase in conventional generation (1,860 MW and 630 MW respectively). This stepwise reduction in new conventional capacity among the scenarios is translated into a similar pattern of CO₂ emissions, with significant differences among the scenarios. The lower fossil-based generation is substituted by hydro in the AMB scenario in the longer run (by 2030). As far as net imports are concerned, more new fossil capacities facilitate more export possibilities. Serbia remains a net exporter from 2020 onwards: only the AMB scenario indicates a minor need for imports in 2030.

CO₂ impacts

In this sub-section we assess the CO₂ emission impacts of the various scenarios using four indicators:

- CO₂ per capita;
- CO₂ per GWh production;
- CO₂ per GWh consumption; and
- fiscal impact of the introduced taxes.

We look at the first three indicators in relation to the ENTSO-E average in order to measure the country’s relative performance.

Emissions of CO₂ per capita in Serbia are at least double the ENTSO-E average in all scenarios and reference years due to the dominance of fossil-based generation, which, although different in the three sce-

Figure 6 Generation mix, net imports and CO₂ emissions in the three scenarios
narios (due to the assumptions about new capacity), remains significant compared to renewables, with the exception of the AMB scenario in 2030 (Figure 7).

The CO$_2$ intensity indicator for electricity production shows a similar pattern: higher but decreasing figures for Serbia compared to the ENTSO-E average. The increase in the CO$_2$ indicator for electricity consumption reflects the fact that Serbia becomes an electricity exporter in 2020 (Figures 8 and 9).

Excise and carbon taxes mean government revenues from the electricity sector. As Figure 10 (page 32) shows, carbon revenues are significantly more important sources than excise taxes on energy products. Due to the stepwise introduction of the ETS carbon price, the revenue streams show an increasing trend, reaching between EUR 600 and EUR 900 million by 2030. Differences among the scenarios are due to the different volumes of the assumed new conventional capacities. Tax revenues could be used to finance important segments of the energy sector, such as renewables or energy efficiency policies.

**Net import position**

The most significant variation between the scenarios appears in relation to import levels. The country is currently close to self-sufficiency: domestic demand is mainly covered by domestic production. By 2020, Serbia will build a strong export position due to the new 1,660 MW of fossil-based capacity and the approximately 700 MW hydro capacity in the REF scenario (Figure 11, page 33). The lower demand and higher RES deployment do not counterbalance the more modest fossil-based capacity development in the CPP and AMB scenarios, resulting in lower exports or even modest imports by 2030 (AMB scenario).

These results are further analysed in Section VI (Sensitivity assessment), where the assumption about the average hydro utilisation rate is relaxed and the production pattern checked against the new assumption regarding the availability of hydro generation.

**Figure 7** CO$_2$ emission levels per capita

![Graph showing CO$_2$ emission levels per capita for Serbia and ENTSO-E average for different years and scenarios.](image-url)
Investment costs

In addition to the generation mix and the resulting CO₂ emissions, it is important to assess the financial consequences of the various scenarios. This will be done by considering two types of costs: the investment costs for generation capacities; and the RES-E support budget.

The required investment costs in the electricity sector for building the new capacities are shown in Table 8. The sources of information concerning unit investment costs (shown in the second column, EUR/kW) are a 2013 publication by the Fraunhofer research organisation; and the Serbian Energy Strategy, which gives region-adjusted values for the investment costs. While most of the renewable and natural gas–based estimates are in a similar range, estimates in the case of hydro and coal generation investment costs deviate significantly. We use benchmark investment cost values, as national quotes generally underestimate costs.

As Table 8 shows, the REF scenario results in higher cumulated investment costs compared to the — quite similar — CPP and AMB scenarios. This means that the additional cost of more hydro, wind and biomass production units is still lower than the cost of the coal-fired plants assumed in the REF scenario, but not in the AMB scenario and only partly in the CPP scenario.

Support budget for renewable energy sources for electricity

The next assessed cost element is the RES support budget, which indicates the overall financial burden of RES-E deployment. We calculate with a benchmark support need, as present national support levels might not reflect the LCOE of the technologies.

The support need for 1 MWh of RES-E is calculated by taking the LCOE of the various generation technologies, which reflects the full average cost of renewable generation, including not only the marginal operating costs, but also the financial returns needed to cover the investments. To make RES production break even, the difference between the LCOE value and the

Figure 8 CO₂ intensity of electricity production (tCO₂/GWh)
market price (P) must be given to producers for every produced MWh of renewable electricity, which is the support need for RES-E production. Base-load and peak-load prices are used from EEMM runs, making it possible to calculate the support need for each MWh of RES electricity produced. We assume that this support need is independent of the type of support applied (feed-in tariff [FIT] or feed-in premium). If this support need is multiplied by the projected quantity of generated RES-E, we arrive at the support budget. This calculation is shown in the following equation:

\[
\text{Support budget} = (LCOE_t - P) \times \text{generated electricity}
\]

- LCOE\(_t\): levelised cost of electricity generation of technology t \(\rightarrow\) average cost of electricity production
- P: modelled base-load electricity price (except PV, where peak-load electricity prices are taken into account)

We use a differentiated LCOE for all RES-E technologies, based on data from the literature. One of the most recent reliable calculations (Ecofys, 2014) gives the following benchmark LCOE data, which were used in this study:

- EUR 55/MWh for hydro;
- EUR 90/MWh for wind;
- EUR 110/MWh for biomass;
- EUR 105/MWh for PV; and
- EUR 80/MWh for geothermal.

Present FIT support in the country for new hydro capacities is set between EUR 74 and EUR 124/MWh for production capacities up to 30 GWh; for PV it is set at EUR 132 to EUR 206/MWh; for wind at EUR 92/MWh; and for biomass at EUR 82 to EUR 132/MWh, depending on the size. The benchmark LCOE values show that the present level of support in Serbia will be sufficient to cover all types of RES in the future as well, so there is no pressure to further increase support for the technologies.

If the RES-E support budget is divided by the total electricity consumption — assuming that all electricity consumers have to pay for the RES-E support — we can also calculate the average RES support fee that
each end user has to pay according to their consumption. These values — the total annual RES-E support budget and the average RES support fee — are shown in Figures 12 and 13.

Figure 12 (page 34) shows the steeply increasing support budget between 2015 and 2020 (mainly due to wholesale price fluctuations), but also the decreasing budget subsequently, despite the continuously growing RES-E capacities. There is a peak in the support budget in around 2020, after which financing becomes less costly in overall terms. In 2020, the electricity price is higher in the CPP and AMB scenarios, resulting in less need for support than in the REF scenario (RES capacities are the same in all three scenarios). The effect of this price difference is cancelled out by higher RES penetration in 2025 and 2030 across the scenarios.

Figure 13 (page 35) illustrates what this support means for end consumers in terms of the price increase they will have to face due to the higher deployment of RES-E. The average RES-E charge on consumed electricity follows a similar trend as in the case of the overall RES-E budget. The extra charge is highest in the REF scenario, reaching a peak of EUR 7.8/MWh by 2020. Although this charge is considerable, it is lower than the 2012 support level in many European member states. According to a 2015 report by the Council of European Energy Regulators (CEER) on EU renewable support schemes, EU member states supported RES-E with an average of EUR 13.68/MWh in 2012.\textsuperscript{9} The trends for 2025 and 2030 and across the scenarios have a similar explanation as the annual RES budget.
**Figure 11** Net import position of Serbia in the three scenarios (negative numbers mean exports)

**Table 8** Cumulated investment costs in 2015–2030 in the three scenarios

<table>
<thead>
<tr>
<th>Investment cost (EUR/kW)</th>
<th>New capacity (MW)</th>
<th>Investment cost (EUR million)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>REF</td>
<td>CPP</td>
</tr>
<tr>
<td>Natural gas</td>
<td>1,000</td>
<td>630</td>
</tr>
<tr>
<td>Coal</td>
<td>2,000</td>
<td>2,225</td>
</tr>
<tr>
<td>Hydro</td>
<td>2,500</td>
<td>1,664</td>
</tr>
<tr>
<td>Geothermal</td>
<td>4,000</td>
<td>1</td>
</tr>
<tr>
<td>Solar</td>
<td>1,100</td>
<td>13</td>
</tr>
<tr>
<td>Wind</td>
<td>1,000</td>
<td>293</td>
</tr>
<tr>
<td>Biomass</td>
<td>3,000</td>
<td>152</td>
</tr>
<tr>
<td>Total</td>
<td>–</td>
<td>4,978</td>
</tr>
</tbody>
</table>
Figure 12 Annual support budget for renewable energy sources for electricity (EUR million)
Figure 13 Average support for renewable energy sources for electricity from end consumers (EUR/MWh)

NOTES

1 “The region” includes Albania (AL), Bosnia and Herzegovina (BA), Croatia (HR), Bulgaria (BG), Greece (GR), Hungary (HU), the former Yugoslav Republic of Macedonia (MK), Montenegro (ME), Romania (RO) and Serbia (RS).


3 A recent example from the region is the Sostanj coal-fired TPP in Slovenia. The initial investment cost estimate was EUR 700 million for a gross 600 MW coal plant (net output 545 MW), and the final investment cost was EUR 1,400 million, equal to EUR 2,500/kW. Source: Balkan Energy News, June 2015.

4 The most common way to calculate LCOE is:

\[ LCOE = \frac{I + \sum_{t=1}^{n} \frac{M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \]

where I = investment costs; M = maintenance costs; F = fuel costs; E = electricity generated in time t; r = discount rate; and t = time period.

5 Subsidies and costs of EU energy, Ecofys, November 2014, Final report DESNL14583

VI. Sensitivity assessment
Hydropower plays an important role in the region, as high levels of hydro capacity exist in almost all the assessed countries. Albania leads these countries, relying almost exclusively on hydropower. The share of hydro generation capacity in Serbia was 32 percent in 2014. It is still worth analysing the impact of dry years to see if it poses a security of supply concern for Serbia. It should be emphasised that this is one of the reasons why most SEE countries are cautious about further increasing their share of hydro capacities, as to do so would be to further deepen their exposure to meteorological conditions (i.e. to the quantity and seasonality of precipitation).

In order to investigate this issue, a sensitivity assessment was carried out that assumed lower precipitation levels than in the previous three scenarios. In the REF, CPP and AMB scenarios, hydro utilisation rates are modelled on the average level of the past eight years, while in the sensitivity runs we checked these scenarios using the lowest utilisation rate during the past eight years, mimicking the situation in a dry year.

As droughts usually occur in the same years throughout the region, we modelled the sensitivity runs accordingly: all neighbouring countries experience a lower level of precipitation. This is an important assumption, since droughts affect these countries in a similar way and drive import and export prices upwards in a similar pattern.

We focus on two aspects in this sensitivity assessment: the substitution possibilities within the country to compensate for the loss in hydro generation; and the impacts on export-import positions. Figure 14 illustrates the substitution effects in the case of lower than usual hydro generation.

As Figure 14 shows, the decrease in hydro generation is substituted by imports, and increasingly by fossil-based generation. In 2015, hydro is fully substituted by an increase in imports. In 2020, the cutback in hydro means a reduction in exports in the REF and CPP scenarios, but — due to self-sufficient production — an increase in fossil-based generation in the AMB scenario. In 2030, Serbia can increase its exports in the region due to the large drop in hydro generation in the neighbouring countries. Total CO₂ emissions change according to the trade position of Serbia:
increasing imports result in a decrease in emissions due to carbon leakage.

Figure 15 shows in greater detail the impact on the export/import position of Serbia.

The overall conclusion to be drawn from the sensitivity assessment is that Serbia, with its ambitious fossil-based capacity plans and relatively modest hydro generation share, can expand its electricity exports in dry years due to the greater vulnerability of the other countries in the region. This underlines the need for regional cooperation, since, due to the adequate interconnections in the SEE region, there is no shortage of capacities to satisfy overall regional demand, even in a dry year. The high (and increasing) interconnection rates in the region would allow for such cooperation, and countries would be in a win-win situation. Such cooperation would also make the country less dependent on the expansion of fossil-based capacities.

Figure 16 illustrates the wholesale price changes in the scenario runs.

While in 2015 the price impact is significant, mainly due to constraints on the supply side, after 2020 the impact is limited to around EUR 3 or EUR 4/MWh in all scenarios. This latter development is probably the result of the capacity developments in the region, which are explored in Section V under “Regional outlook”.

**Figure 15** Changes in the net import position of Serbia

![Figure 15](image_url)
Figure 16 Base-load price changes in Serbia (EUR/MWh)
VII. Network impacts
The electricity transmission system in SEE today is relatively well developed for the current level of power exchanges in the region. However, the exchange possibilities in the region are limited by bottlenecks in both internal networks and interconnections. Improving the balance between energy supply and demand is crucial in order to boost and sustain economic development in SEE. It also means that TSOs should be prepared to support energy trading between their control areas and with their neighbours through the appropriate development of their transmission networks.

The network analysis focuses on the four project countries: Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia. However, the representative trade flows with neighbouring countries are also included in the assessment (e.g. with Romania and Bulgaria). The main network elements in the region are presented in Figure 17.

Commercial congestion is permanently present in flow directions from Romania to Serbia and from Bulgaria to Serbia, due to the fact that Romania and Bulgaria have a surplus of electrical energy and that Serbia is used as a transit area towards Montenegro, the former Yugoslav Republic of Macedonia and Greece (countries with an electrical energy deficit).

Prior to October 2004, the SEE power system was not connected for unified parallel operation. Following reconnection with the first synchronous zone of the Union for the Coordination of Transmission of Electricity (UCTE) in October 2004, power system conditions in SEE changed dramatically. Power utilities in the region began a process of deregulation and privatisation. Due to the post-socialist collapse in industrial consumption, SEE was initially characterised by a surplus of installed generation capacity. Relatively cheap electricity from SEE became a great

Figure 17 Geographical coverage of the network analysis
market opportunity. Countries in the region agreed to create a stable common regulatory and market framework capable of attracting investment in power generation and transmission networks.

All these factors have a substantial impact on the operation and development of the regional transmission network. Compared to other European regions, SEE is characterised by large interconnection capacities at a 220 kV voltage level and above.

**Planned new network elements**

There are comprehensive, realistic plans for the development of the transmission network in SEE, and current practice suggests that these development plans are more or less being implemented. Aside from the fact that the countries in the region can be regarded as well connected, new investments are expected, especially for cross-border elements or internal connections that will have a significant impact on cross-border capacities.

The planned new transmission lines, listed in accordance with the ENTSO-E Ten-Year Network Development Plan (TYNDP), and strategic development and investment projects in each country, are shown in Figure 18.

In the three SLED scenarios (REF, CPP and AMB), generation capacities — both distributed RES generation and conventional generation — and the assumed total electricity consumption change according to the agreed scenario definitions. The introduction of these changes in the network model has many impacts, which are assessed under the following categories:

- steady-state and contingency analyses;
- evaluation of NTC; and
- calculation of transmission grid losses.

The detailed network modelling methodology for these three areas is presented in the Annex, following the network modelling description.
Results of network modelling

The winter and summer operating regimes for the 2015, 2020 and 2025 development stage in all scenarios were assessed in the network modelling stage. The year 2015 was considered as the reference year in the assessment, reflecting the present network topology and the currently available generation capacities.

Steady-state and contingency analyses

Calculations within system studies were conducted on regional network models for SEE prepared for 2020 and 2025. The power systems of the four assessed countries were modelled according to the data collected and the Southeast Europe Cooperation Initiative (SECI) regional model for 2020/2025, the available respective national development plans, and the transmission system development set out in the ENTSO-E TYNDP 2012–2022.

System balances

Power system balances (in MW) in the assessed countries, analysed for all regimes (winter and summer) and scenarios, are presented below.

In 2020:

- Montenegro is an importing country in the summer regime, while in the winter regime it is an exporting country due to the significant number of RES.
- Serbia is an exporter of 1,000 MW in both regimes.
- Albania is an exporting country.

Due to new capacities (conventional, especially TPPs), in 2025:

- Serbia becomes a large exporter.
- Montenegro is an exporter in the winter peak regime (due to a certain number of RES), but in the summer peak regime it still imports a small amount of power.
- Albania only exports in the winter peak regime (AMB and REF) at 150 MW, and in other regimes it is balanced.

The former Yugoslav Republic of Macedonia is an importer in all regimes and scenarios.

(N-1) Security criteria

In 2015, there are no high-loaded elements at 220 kV and 400 kV voltage levels in the assessed countries.

The results of the security assessments for 2020 and 2025 are shown in Tables 9 and 10 for the whole of the assessed region, as contingencies appear at regional but not at country level.

In 2020, the following strengthening is necessary:

- In all scenarios, the tripping of the OHL 220 kV Fierza (AL)-Titan (AL) line leads to the overloading of the OHL 220 kV VauDejes (AL)-Komani (AL) line. The new OHL 220 kV Komani (AL)-Titan (AL) line solves the problem (70 km).
- Some windfarms that are to be constructed within the Serbian power utility EPS will be connected to the OHL 220 kV Zrenjanin (RS)-Pancevo (RS) line. As a consequence of overloading in that area, in the CPP scenario the conductor on the OHL 220 kV Pancevo (RS)-Zrenjanin (RS) line should be replaced with a higher capacity one (length of approximately 22+44 km).
- In the AMB scenario, only the replacement of a 1 km length of conductor on the OHL 220 kV HIP (RS)-Pancevo (RS) line is required (in addition to the OHL 220 kV VauDejes [AL]-Komani [AL] line).

Generally speaking, the CPP scenario requires greater additional investment than the other two (as a consequence of more new elements). The REF and AMB scenarios require the same level of investment, but less than the CPP scenario.

In 2025, the following strengthening is necessary:

- In all scenarios, the tripping of the line OHL 220 kV Fierza (AL)-Titan (AL) leads to the overloading of the OHL 220 kV VauDejes (AL)-Komani (AL) line. The new OHL 220 kV Komani (AL)-Titan (AL) line solves that problem (70 km).
- Some windfarms to be constructed within the Serbian EPS will be connected to the OHL 220 kV Zrenjanin (RS)-Pancevo (RS) line. As a consequence of overloading in that area, in the CPP and AMB scenarios the conductor on the OHL 220 kV HIP (RS)-Beograd 8 (RS) line should be replaced with a higher-capacity one (length of approximately 14.5 km).

The REF scenario requires less additional investment than the other two (as a consequence of fewer new
The CPP and AMB scenarios require the same level of investment.

We can conclude from the results that the connection of new RES causes some new overloading in Serbia and Albania, while in Montenegro and the former Yugoslav Republic of Macedonia RES capacity development has no impact on the 400 kV and 220 kV transmission network. Thus for Serbia, the newly installed RES generation capacities assumed in the scenarios pose some problems to the electricity network. The HIP–Belgrade OHL should be reinforced, although the line length is limited (14.5 km).

### Table 9 Contingencies in 2020

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Winter max</th>
<th>Summer max</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REF</strong></td>
<td>OHL 220 kV Fierza (AL)–Titan (AL)</td>
<td>OHL 400 kV Podgorica (ME)–Tirana (AL)</td>
</tr>
<tr>
<td></td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
<td>OHL 220 kV Komani (AL)–Titan (AL)</td>
</tr>
<tr>
<td></td>
<td>New OHL 220 kV Komani (AL)–Titan (AL)</td>
<td>OHL 220 kV Komani (AL)–Titan (AL)</td>
</tr>
<tr>
<td><strong>CPP</strong></td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>OHL 400 kV Panccevo (RS)–Beograd20 (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td></td>
<td>OHL 400 kV Mjdox (RS)–TENT B (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td></td>
<td>TR 400/220 SS Panccevo (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td></td>
<td>OHL 220 kV WPPs (RS)–Pancevo (RS)</td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
</tr>
<tr>
<td></td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
</tr>
<tr>
<td><strong>AMB</strong></td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>New OHL 220 kV Komani (AL)–Titan (AL)</td>
<td>Changing of the conductors and earth wires and OPGW across the Danube River with higher capacity (14.5 km)</td>
</tr>
<tr>
<td></td>
<td>New OHL 220 kV Komani (AL)–Titan (AL)</td>
<td>Changing of the conductors and earth wires and OPGW with higher capacity (14.5 km)</td>
</tr>
<tr>
<td></td>
<td>Changing of the conductors and earth wires and OPGW across the Danube River with higher capacity (1 km)</td>
<td></td>
</tr>
</tbody>
</table>

### Net transfer capacity

According to the ENTSO-E methodology, the results of the gross transfer capacity (GTC) calculation should be used for market analysis. However, since in the current operation of the power systems NTC values are used to describe limitations in transfer capacities between countries, NTCs were calculated on the borders of the analysed countries. These capacities were used as inputs in the market analysis.

Capacity calculation is always related to a given power system scenario — that is, generation schedule and pattern, consumption pattern and available network state. These constitute the data that make it possible to build up a mathematical model of the power system (load flow equations). The solution of this model
provides knowledge of the voltages in the network nodes and the power flows in the network elements, which are the parameters monitored by a TSO in order to assess system security.

Before the results are presented, it is important to underline that NTC values, beside network topologies, depend on the generation pattern of the region as well as the engagement of the generation units in one particular system.

The NTC values for the three assessed scenarios for 2020 and 2025 are presented in Figures 19 to 22.

The NTC values for the AMB and CPP scenarios are higher than for the REF scenario on most of the borders for the summer regime (with the exception of the Macedonian border), while there is no such individual trend in the winter regime.

Similarly to 2020, in 2025 the deployment of renewables increases NTC values on most of the borders in both the winter and summer regimes. In the case of the Montenegro–Serbia and Former Yugoslav Republic of Macedonia–Serbia direction there is a slight decrease in the NTC values for the winter regime. In the summer regime, the Serbia–Albania direction is affected negatively.

**Transmission grid losses**

Transmission losses were calculated for all four analysed countries. The analyses were carried out for three scenarios with different levels of RES, two regimes (winter maximum and summer maximum) and three target years (2015, 2020 and 2025).

<table>
<thead>
<tr>
<th>Scenario 2025</th>
<th>Tripping</th>
<th>Overloading</th>
<th>Solution</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>REF</strong></td>
<td>Winter max</td>
<td>OHL 220 kV Fierza (AL)–Titan (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 400 kV RP Drmno (RS)–Smederevo (RS)</td>
<td>OHL 400 kV Pancovo (RS)–Beograd (RS)</td>
</tr>
<tr>
<td><strong>CPP</strong></td>
<td>Winter max</td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV Pancovo (RS)–Beograd20 (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td><strong>AMB</strong></td>
<td>Winter max</td>
<td>OHL 220 kV Komani (AL)–Kolace (AL)</td>
<td>OHL 220 kV VauDejes (AL)–Komani (AL)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV Pancovo (RS)–Beograd20 (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
<tr>
<td></td>
<td>Summer max</td>
<td>OHL 220 kV WPPs (RS)–Zrenjanin (RS)</td>
<td>OHL 220 kV HIP (RS)–Beograd8 (RS)</td>
</tr>
</tbody>
</table>

Table 10 Contingencies in 2025
**Figure 19** Net transfer capacity values for 2020 (winter regime)

![Bar chart showing net transfer capacity values for 2020 (winter regime). The chart compares the capacity values across different regions and scenarios (REF, CPP, AMB).]

**Figure 20** Net transfer capacity values for 2020 (summer regime)

![Bar chart showing net transfer capacity values for 2020 (summer regime). The chart compares the capacity values across different regions and scenarios (REF, CPP, AMB).]
Figure 21 Net transfer capacity values for 2025 (winter regime)

Figure 22 Net transfer capacity values for 2025 (summer regime)
The total losses in Serbia’s power systems are shown in Table 11.

The losses are highly dependent on electricity exchanges, transmission reinforcements, levels of production and consumption, as well as the connection points of power plants and consumers. Power losses are higher in the winter regime and lower in the summer regime due to the large exchanges between the countries during the winter regime in the period 2015–2030.

The increase in RES in overall installed capacities, presented through the three scenarios, will produce lower transmission losses in gross consumption in Serbia in 2025 and similar lower than REF losses in the CPP and AMB scenarios in 2020. A regional comparison of losses can be found in the regional study. Total annual losses in Serbia’s power systems are shown in Figure 23.

Table 11 Transmission losses in 2015, 2020 and 2025 in Serbia, for all scenarios and regimes

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2020</th>
<th>2025</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Winter</td>
<td>Summer</td>
<td>Winter</td>
</tr>
<tr>
<td>Equivalent duration time</td>
<td>2,841</td>
<td>2,964</td>
<td>2,841</td>
</tr>
<tr>
<td>of maximum losses (h)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission losses</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>REF</td>
<td>130.3</td>
<td>135.1</td>
<td>207.3</td>
</tr>
<tr>
<td>CPP</td>
<td>-</td>
<td>-</td>
<td>206.6</td>
</tr>
<tr>
<td>AMB</td>
<td>-</td>
<td>-</td>
<td>199</td>
</tr>
<tr>
<td>Yearly transmission</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>losses (GWh)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>REF</td>
<td>912.7</td>
<td>954.4</td>
<td>1,030.5</td>
</tr>
<tr>
<td>CPP</td>
<td>-</td>
<td>-</td>
<td>903.8</td>
</tr>
<tr>
<td>AMB</td>
<td>-</td>
<td>-</td>
<td>909.8</td>
</tr>
</tbody>
</table>
NOTES

(N-1) Security criteria refer to the assessment of the electricity system when the largest capacity (either network or generation) is removed from the system to simulate the state of the system with the outage of the largest-capacity element. In this case, an outage of a network element is modelled.

Figure 23 Annual transmission losses in Serbia for all scenarios
VIII. Annex
The two applied models — the EEMM and the EKC network model — are described in detail in this annex.

The European Electricity Market Model

The EEMM simulates the operation of a European electricity wholesale market. It is a partial equilibrium model.

Geographical scope

Figure 24 shows the geographical coverage of the model. In the countries coloured orange, electricity prices are derived from the demand–supply balance. In the other group of countries, shown in blue, prices are exogenous.

Market participants

There are three types of market participant in the model: producers, consumers and traders. Markets are assumed to be perfectly competitive — that is, actors are price takers.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production, which is constant at the unit level, and generation is capacity constrained at the level of installed capacity.

The EEMM works with power plants at the unit level, and there are close to 5,000 power plant units in the model. For individual power plants, the following essential information is contained by the model: installed capacity, year of construction, technology and main fuel type.

Within the electricity sector we can distinguish 12 different technologies: biomass-fired power plants; coal-fired plants; lignite-fired plants; geothermal plants; heavy fuel oil–fired plants; light fuel oil–fired plants; hydropower plants; wind power plants; solar power plants; nuclear plants; natural gas–fired plants; and tidal power plants.

The model takes into account short-term variable costs with the following four main components: fuel costs; variable OPEX; excise tax; and CO₂ costs (where applicable). The fuel cost in each generation unit depends on the type and price of the fuel and the overall efficiency of electricity generation. The latter is taken from the literature and empirical observation for various power plant types and commissioning dates. When the market price is above the marginal
generation cost of a unit, the unit is operated at full available capacity, and if the price is below the marginal cost there is no production.

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. The slope of the demand curve is the same for all countries. When determining future consumption we consider the relationship between past GDP and electricity consumption figures separately for each country. Based on this relation and the GDP forecast we establish the expected annual electricity consumption.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Within the model, a country appears as a node — that is, there are no network constraints within the country, only between countries. Cross-border trade takes place on capacity-constrained interconnectors between neighbouring countries. Electricity exchanges occur until either prices, net of direct transmission costs or export tariffs, equalise across the markets; or the transmission capacity of the interconnector is reached.

**Equilibrium**

The model is a partial equilibrium model and calculates the equilibrium allocation in all domestic electricity markets under the following constraints:

- Producers maximise their short-term profits, given market prices.
- Total domestic consumption is given by the aggregate electricity demand function in each country.
- Electricity transactions (exports and imports) occur between neighbouring countries until market prices are equalised or transmission capacity is exhausted.
- Energy produced and imported is in balance with energy consumed and exported.

Market equilibrium always exists and is unique in the model.

The calculated market equilibrium is static: it only describes situations with the same demand, supply and transmission characteristics. To simulate the price development of more complex electricity products, such as those for base-load or peak-load delivery, we perform several model runs with typical market parameters and take the weighted average of the resulting prices.

When modelling, hourly markets are simulated, and these simulations are independent from one another — that is, ramp-up costs are excluded. Within the model, the equilibrium for a given hour (with respect to quantities and prices) is reached simultaneously by the producer and transmission segments. Figure 25 describes the operation of the model.

By determining the short-run marginal cost and available capacity for each power plant we can construct

---

**Figure 25** Operation of the model

- **Input**: Marginal generation cost, Available generation capacity, Cross border transmission capacity, Demand curves by country, Supply curves by country
- **Model**: Equilibrium prices by country, Electricity trade between countries, Production by plant
the supply curve for each country — in other words, the merit order curve. Taking into consideration the constraints of cross-border capacities and the demand curves characterising each country, we arrive at the input parameters of the model. The model applies these data to maximise European welfare, which is the sum of producer and consumer surpluses. As a result of model computations we get the hourly equilibrium price for each country, the hourly commercial transfers between the countries, and the production of each power plant unit.

We simulate the short-term market represented by a selected hour. We typically aim to model an annual period, rather than a single hour, therefore on the demand side it is necessary to settle on a given number of reference hours through which annual average prices are approximated. In the model, 90 reference hours are established.

**Network representation**

The EEMM assumes that each country is a node — in other words, network constraints do not exist within any of the countries. Cross-border capacities, on the other hand, may impose a serious limitation on the trading of electricity. Scarcity is expressed through the NTC.

The EKC model provided modelled NTC values for the four target countries of the SLED project and the neighbouring regions (directly connected to the target countries), while for the rest of the countries modelled by the EEMM, data from ENTSO-E were used.

**The EKC network model**

A regional load-flow model on which analyses are performed was developed based on SECI regional transmission models for 2015 (also used as the current model), 2020 and 2025, updated according to the assumptions of the ToR.

All analyses were performed for the years 2015, 2020 and 2025 with two typical regimes: winter peak (third Wednesday in January at 19:30), and summer peak (third Wednesday in July at 10:30).

The topology of transmission networks in SEE countries (Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Greece, the former Yugoslav Republic of Macedonia, Romania and Serbia) is taken according to the SECI regional model, updated according to generation surplus projections in SEE. Other neighbouring countries (France, Switzerland, Germany, Ukraine and Slovakia) are modelled as injections (over inter-connection lines); while Austria and Hungary are presented with the full model adopted according to the UCTE system adequacy forecast 2014–2024.

The system study was performed on already existing studies using the current regional system models developed under SECI, checked and updated by the TSOs. System studies and planning were done on a regional basis, as was the definition of the border crossing points.

Electric power systems in SEE were modelled with their complete transmission networks (at 400 kV, 220 kV, 150 kV). The power systems in the four assessed countries were modelled in addition at the 110 kV voltage level. The network equivalent of Turkey (i.e. European part) and the rest of ENTSO-E Continental Europe (modelled over the X-node injections) were also used in the model.

The following assessment was carried out in the network study:

- **Load-flow data collection**, which includes:
  - an assessment of the existing electricity network situation within Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, together with the regional context; and
  - a definition of the network topologies and regimes for 2015, 2020 and 2025, using realistic scenarios for demand growth, generation expansion, transit flows, RES integration and HVDC links.
- **TTC/NTC evaluation** among Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia in all directions, for all topology scenarios, with reference to each target year and regime.
- Assessment of transmission grid losses with and without a level of energy production from RES.

**Load-flow data collection**

In the process of collecting the data needed for load-flow studies, representatives of the four countries reviewed and updated the proposed datasets, which include:

- Demand level in the agreed regimes and power exchanges in 2015, 2020 and 2025 for two characteristic regimes:
third Wednesday in January at 19:30 (winter peak); and
- third Wednesday in July at 10:30 (summer peak).
- A list of new generation facilities and generation units to be decommissioned up to 2015, 2020 and 2025.
- A list of new elements in the transmission network.
- The level of transmission reliability margin used in the evaluation of the NTC.

These data were used for the preparation of the network models for 2015, 2020 and 2025, which were used for the load-flow analyses.

**Demand**

The development of demand in two characteristic regimes (third Wednesday in January at 19:30 [winter peak] and third Wednesday in July at 10:30 [summer peak]) in 2015, 2020 and 2025 were analysed on the basis of:

- ENTSO-E online datasets;
- ENTSO-E scenario outlook and adequacy forecasts;
- national demand projections; and
- consultants’ datasets from relevant projects in the SEE region.

Since network forecast models are used in our analysis, demand excludes transmission and distribution losses, as well as the power plants’ own consumption and pumping.

**Network modelling methodology**

The network modelling methodology comprises three parts:

- steady-state and contingency analyses;
- an evaluation of NTC; and
- the calculation of transmission grid losses.

These parts are introduced in detail below.

**Steady-state and contingency analyses**

For the defined scenarios, steady-state load flows are calculated and contingency (n-1) analyses performed. Security criteria are based on the loadings of lines and voltage profile and checked for each scenario analysed.

Load-flow analyses provide an insight into transmission network adequacy for the observed scenarios of exchanges and a comparison of observed configurations, under steady-state and (n-1) operating conditions.

Load-flow assessment is a basic step in NTC evaluation and comprises the following analyses:

- steady-state AC load flow;
- security (n-1) assessment; and
- voltage profile analysis.

In the analysis of voltage profiles, voltage limits are taken according to the respective national grid codes.

It should be stressed that only the 400 kV and 220 kV networks were assessed from a security point of view. There are many new RES to be connected to lower-voltage networks, which might cause problems in networks of 110 kV or lower, although this should be solved via the national transmission network plans.

**Evaluation of net transfer capacity**

The TTC and NTC were evaluated between Albania, the former Yugoslav Republic of Macedonia, Montenegro and Serbia, as well as between these countries and their neighbours, in all directions, for all topology scenarios, and with reference to each target year and regime. A final assessment was also made of the TTC/NTC additional values as a result of new interconnections and the strengthening of the major energy transit routes.

It is also important to note that TTC, NTC, base case exchange (BCE), already allocated capacity (AAC) and available transfer capacity (ATC) are the exchange programme values; these are not the physical flows and generally differ from the physical flows at the interconnection lines (except in particular cases of radial operation).

The solution of this model is the so-called base case and is the starting point for the computation. This base case can already contain exchange programmes between TSOs and control areas. These are the various transactions likely to exist in the forecasted situation according to what has been observed in the past.

The TTC value may therefore vary (increase or decrease) when approaching the time of programme execution as a result of a more accurate knowledge of generating unit schedules, load pattern, network topology and tie line availability.
The general definitions of transfer capacities (TTC, NTC) and the procedures for their assessment are according to ENTSO-E, and the practice and experience of regional SEE TSO working groups.

**BASE CASE EXCHANGE**
In the base case, for a given pair of neighbouring control areas A and B, for which capacities are to be computed, the global exchange programme known as BCE exists. The BCEs are the programme (contractual) values related to the base case model.

**MAXIMUM ADDITIONAL EXCHANGE**
The maximum additional programme exchange (over the BCE) that meets the security standards is indicated by $\Delta E_{\text{max}}$. An additional programme exchange is performed by decreasing generation in area A, and simultaneously increasing generation in area B.

**TOTAL TRANSFER CAPACITY**
The TTC is the maximum exchange programme between two areas, compatible with the operational security standards applicable to each system, if future network conditions, generation and load patterns are perfectly known in advance.

$$\text{TTC} = \text{BCE} + \Delta E_{\text{max}}$$

**TRANSMISSION RELIABILITY MARGIN (TRM)**
The TRM is a security margin that deals with uncertainties in the computed TTC values arising from:

- unintended deviations in physical flows during operation due to the physical functioning of load frequency control (LFC);
- emergency exchanges between TSOs to deal with unexpected unbalanced situations in real time; and
- inaccuracies, for example in data collection and measurements.

**NET TRANSFER CAPACITY**
The NTC is the maximum exchange programme between two areas compatible with the security standards applicable in both areas, taking into account the technical uncertainties in future network conditions.

$$\text{NTC} = \text{TTC} - \text{TRM}$$

**Transmission grid losses**
The assessment of electricity losses is based on the equivalent duration time of losses in winter peak and summer peak periods. This approach takes into account that the impact on losses can be different in these two regimes, meaning that annual losses can be determined more accurately.

The assessment of electricity losses is based on the equivalent duration time of maximum losses. The method used to determine this equivalent duration time requires two parameters as input: maximum demand and load factor. These two parameters are obtained from an analysis of the load duration diagram of the analysed year for the respective power system.

Yearly losses are calculated based on grid losses in MW calculated for the two analysed regimes — winter peak and summer peak — and the equivalent load duration time of the respective loads in these regimes. With the calculated equivalent duration time of maximum losses for the respective period, yearly transmission grid losses (GWh) are calculated by multiplying this value with power losses (MW):

$$W_{\text{loss}} = W_{\text{loss}}^{\text{winter peak}} + W_{\text{loss}}^{\text{summer peak}} \quad \text{[GWh]}$$

$$W_{\text{loss}}^{i} = \frac{P_{\text{loss}}^{i}(\text{MW}) \times T_{\text{eq}}^{i}(\text{h})}{1000} \quad \text{[GWh]}$$

$P_{\text{loss}}^{i}$ - Active power losses in MW in specific regime $i$

$T_{\text{eq}}^{i}$ - Equivalent duration time in hours for the respective load in regime $i$
Decarbonisation modelling in the electricity sector

Serbia

Support for Low-Emission Development in South Eastern Europe (SLED)