Decarbonization Action Plan for Elektroprivreda Srbije - Summary –

1. Introduction

This Decarbonization Action Plan sets out a comprehensive roadmap for transitioning Elektroprivreda Srbije (EPS) towards climate neutrality by 2050. The plan complies with the Serbian Integrated National Energy and Climate Plan (INECP), the EU Green Agenda and broader global commitments under the Paris Agreement. As EPS currently accounts for more than 90% of Serbia's electricity generation and approximately 42% of national greenhouse gas (GHG) emissions, the transformation of the production portfolio is a key prerequisite for achieving the country's climate and energy goals.

The adoption of EU legislation (European Commission, 2025b), which is one of the conditions in the accession process, also brings the obligation to introduce the Emissions Trading System (EU ETS). The energy sector, manufacturing, aviation and maritime transport will have to pay for their greenhouse gas emissions.

In addition, the EU plans to resolve carbon "leakage" issue by introducing a Carbon Border Adjustment Mechanism (CBAM) (European Commission, 2025a). The CBAM aims to impose import tariffs for third countries on cement, iron and steel, aluminum, fertilizers, electricity and hydrogen in order to level the conditions with EU producers. This further emphasizes the need to decarbonize the production portfolio, for EPS (Elektroprivreda Srbije) to remain a competitive trading partner with the EU.

On the other hand, EPS, as the dominant energy entity for generation and supply of electricity, is responsible for ensuring the security of electricity supply in Serbia (EPS, 2025).

The production portfolio of EPS is dominated by domestic lignite-fired thermal power plants with about 55% of the total capacity, followed by about 35% of hydro capacity and a minor share of natural gas-fired capacities. Such a structure is gradually becoming unsustainable in both environmental and economic terms, as it is expected that carbon dioxide emission taxes will start to be levied in Serbia, with an increase from 4 €/tCO_2 to 160 €/tCO_2 by 2050. The cost of EPS' production could triple, which would seriously jeopardize the sustainability of the company if timely and adequate preparations are not made.

In order to identify the optimal transition strategy, detailed energy and financial modeling was done using the LEAP (Low Emissions Analysis Platform) tool, based on the principle of the lowest total costs, while following the requirements of energy security, environmental standards and INECP targets.

Several decarbonization pathways have been developed, of which the most optimal long-term considerations are provided as scenarios:

- **LT Dominant scenario where - EPS retains its leading role, with over 85% of the market share in generation through introducing solar, wind and hydropower, with the support of pumped storage hydropower plants**
- **LT Decentralized scenario – only EPS's market share drops to approximately 65% in generation, with more considerable share of EPS within the partnerships on the market where the non-capacities-based trade would significantly contribute to the national electricity supply in which the role of markets would increase, as well as providing electricity and other producers.**

In order to provide a long-term vision, with effective results for the near future, a single roadmap until 2035 has been selected with two long-term options introduced after 2035. The period up to 2035, the same for both scenarios, was modeled with the assumptions of a "dominant centralized scenario" and after 2035, two scenarios were modeled, with different mechanisms for achieving the decarbonization agenda. The first long-term option continues to follow the pathway of the "dominant centralized scenario", and the second aims to introduce a larger share of the private sector within partnerships with EPS and new market mechanisms, i.e. following the pathway of the "decentralized scenario". Both scenarios provide for decarbonization but differ in the role of EPS in the market, investment needs, import dependency and exposure to financial risks.

Key results show that both scenarios are technically feasible and allow for almost complete decarbonization of EPS by 2050 where:

By 2050, in both scenarios, EPS will reach 99% of electricity generation from renewable sources, with decommissioning lignite-fired generation as well as lignite production, while 0.7 GW of capacity in Kostolac (B2 and B3) will be kept as the strategic cold reserve, in line with the recommendations of ENTSO-E.

The total installed EPS capacity increases from 7.9 GW (2025) to: 25.8 GW in LT Dominant scenario, i.e. 18.2 GW in LT Decentralized scenario by 2050 - Growth is primarily driven by solar and wind power, which account for 61–72% of total capacity in 2050, with significant expansion of hydro and pumped storage power plants to balance the system.

CO_2 emissions are reduced by approximately 99% by 2050 in both scenarios compared to the base year.

In 2050, EPS retains 88% of the market share and a net export position of 1.9 TWh in the LT Dominant scenario, while in the LT Decentralized scenario this share drops to 63% of the market share, with significant reliance through electricity purchases on the market and production of other producers (up to 37% of national demand).

The period 2030-2039 represents the most intensive phase of investment in both scenarios.

After 2040, with the complete cease of coal-fired generation and the growing share of renewables, production costs decrease to 45 EUR/MWh (LT Dominant) and 52 EUR/MWh (LT Decentralized) by 2050, ensuring long-term profitability and competitiveness.

Total investments are estimated at EUR 27.0 billion in the LT Dominant scenario and EUR 22.5 billion in the LT Decentralized scenario. In order to ensure financial sustainability in the transition period, which is a key prerequisite for the success of EPS decarbonization, it is necessary to consider the implementation of long-term PPAs, joint ventures, CO_2 emission taxes as well as support from development partners.

During the implementation of the Decarbonization Action Plan, it is necessary to permanently manage a just transition of the workforce, bearing in mind the gradual decrease of employees within the activities related to the thermal and mining sector, in which production will be gradually optimized with a clear aim at ensuring energy security of Serbia.

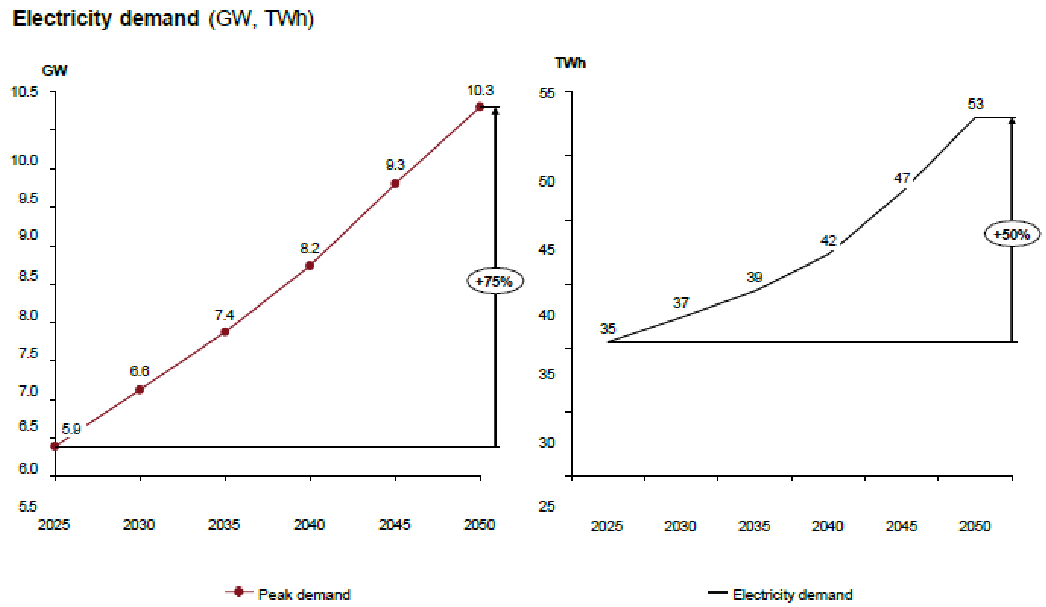
The Action Plan clearly shows that the decarbonization of EPS is not only a climate commitment, but also a strategic necessity to preserve energy security and market competitiveness. The timely transition enables EPS to transform from a coal-dependent company into a regional leader in clean energy, ready for the low-carbon electricity market.

2. Key assumptions and limitations

The dynamics of decarbonization, assumptions and projections that affect it were determined by INECP and were used as a basis for the development of the EPS Decarbonization Action Plan, thus achieving compliance with national goals. The main driver for the results obtained in the power sector is the projected increase in electricity consumption, which, according to INECP, implies significant electrification in all consumption sectors and increased demand for renewable energy sources.

In accordance with INECP projections, an increase in electricity consumption of about 50% by 2050 is assumed, compared to the current level, i.e. from approximately 35 TWh in 2025 to 53.2 TWh by 2050. Of this, 45.9 TWh is final consumption, 0.7 TWh is consumption in the energy sector, 4.8 TWh is consumption for hydrogen production and about 1.8 TWh is net exports.

In addition, to determine the required capacity and reliability of the system, peak consumption was analyzed, where an increase of about 75% is expected, from 5.9 GW in 2025 to 10.3 GW in 2050. The dynamics of electricity demand and peak loads are shown in the following diagram:



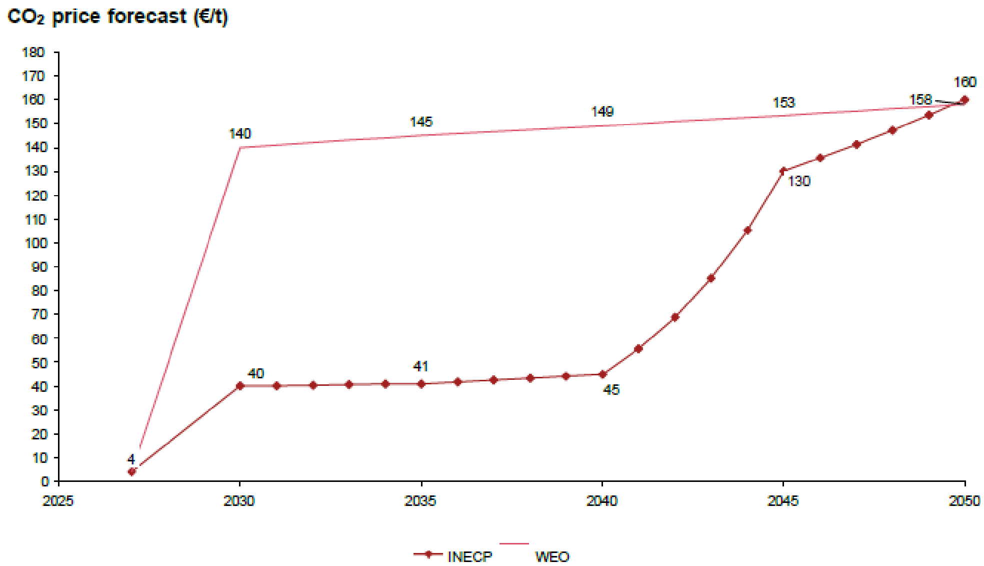
At present, fossil fuels account for 45% of final energy consumption (including all sectors), while in 2050 their share will decrease to 36%. It is planned that the difference in the structure of final energy consumption will be compensated for by additional RES and electricity available from EPS generation capacities and on the market. Currently, electricity represents 28% of final consumption, while it is projected to reach a level of about 41% in 2050 (Government of the Republic of Serbia, 2023).

In addition to the projection of electricity consumption, the following assumptions are uniformly applied for all scenarios:

- demand for heat energy and energy efficiency projections, aligned with current needs, expected growth and energy efficiency trends from INECP
- projection of wholesale electricity prices in accordance with the forecast of ICIS (Independent Commodity Intelligence Services), from July 2024
- prices for carbon dioxide emissions – projections in accordance with INECP
- natural gas price calculations for combined heat and power plants are based on the TTF (Title Transfer Facility) until 2029, with the WEO (World Energy Outlook) forecast applied for the period up to 2050
- coal prices and investments in mining resources in accordance with EPS projections and plans
- projected efficiency of the existing thermal power plants
- transmission capacity supports the integration of all new renewable energy connections in all scenarios.

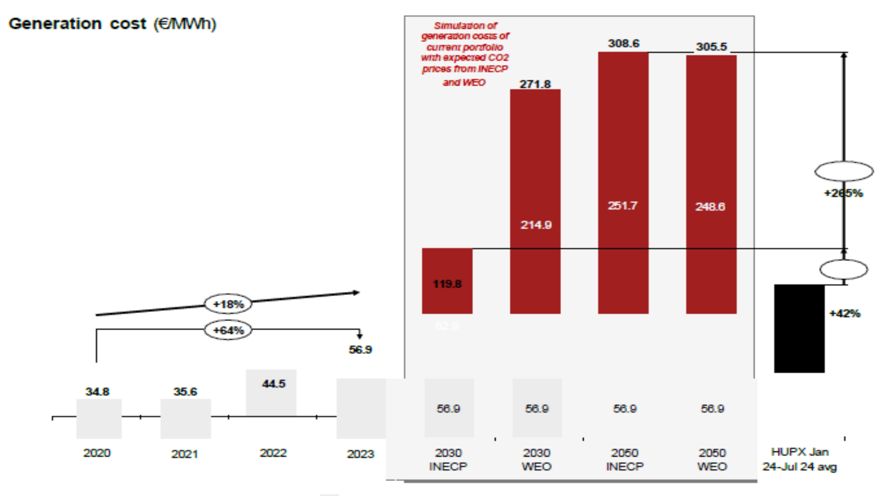
Starting from 2027, according to INECP, the cost of carbon dioxide emissions will go from a projected 4 EUR/tCO2 eq in 2027, with a projected increase to 40 EUR/tCO2 eq by 2030, to 160 EUR/tCO2 eq by 2050 (diagram below). With the presented price escalation (according to the latest projections), it is expected that the cost of carbon dioxide emissions, by 2030, will represent a third of the total cost of electricity generation, which represents a significant competitive risk for the existing generation portfolio.

When testing the sensitivity with the more recent CO2 price forecast from the WEO, the difference is threefold compared to the INECP projection for the period 2035-2040, significantly higher by 2045 to even out only in 2050 – differences in the planned dynamics of increase in carbon dioxide emission prices further increase the risk to the financial sustainability of EPS:



In projections where the current structure of the production mix is kept, production costs for EPS would double by 2030 and triple from there by 2050, as can be seen in the following diagram. The increase in costs, caused by the increase in carbon dioxide prices, far exceeds the current HUPX and exceeds the projected wholesale electricity prices (ICIS 2024, for the period from 2025 to 2050). Such a scenario highlights the urgent need to strategically adjust portfolios to manage rising costs and maintain competitiveness in the market.

If EPS keeps a similar generation profile as today, the cost of carbon dioxide emissions will strongly increase the cost of electricity generation to more than 300 €/MWh by 2050, well above the projected wholesale price.



Source: EPS, INECP, WEO (Stated Policies Scenario)

To avoid the risks of non-competitiveness in the market, it is necessary to set out the portfolio, which relies on renewable energy sources, while maximizing the existing infrastructure and minimizing the costs for EPS.

Also, for providing comparability of the scenarios, the necessary assumptions are based on the following basic principles:

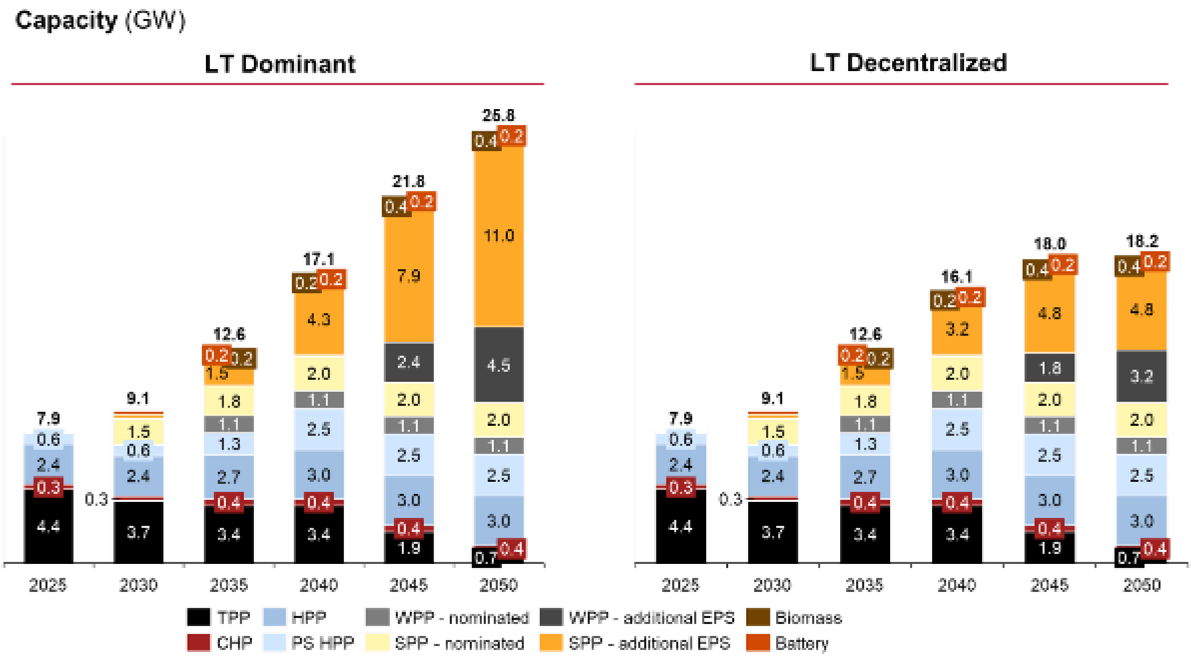
1. All modelled scenarios are aligned with INECP, the Energy Strategy and carbon neutrality by 2050, with a maximum deviation of 10% from the post-2040 decarbonization targets.
2. Thermal power plants that remain in operation after 2030 include investments in desulfurization and denitrification equipment,
3. EPS production portfolio compliant with environmental standards,
4. Taking into account strategic national objectives when modelling security of supply (e.g. import/export targets and requirements);
5. The results that offer the lowest total costs over the modelling period (including strategic constraints) in each scenario were analyzed.
6. The energy of EPS may also include energy that is not produced from its own capacities (trading, PPA, partnerships etc.).
7. A competitive portfolio implies integration and connection with the European market.

In order to bring the scenarios closer to realistic conditions, certain limitations due to national policies are included:

- Trade limitations – until 2035 and throughout the modelling horizon for the Dominant scenario – EPS is assumed to keep a net export position (in line with national strategies), even though production costs exceed projected wholesale electricity prices during 2030-2040 period. As a result of such a limitation, there is some deviation from the "least cost" criterion, but it reinforces national energy security objectives.
- Obligation of district heating – in all scenarios, EPS continues to provide district heating, in accordance with current practice. This obligation requires the continued operation of certain coal-fired plants, thereby delaying their decommissioning despite their economic uncompetitiveness in the short and medium term.
- Limitations on the use of biomass – biomass-fired CHPs were not introduced before 2035 due to technical limitations and underdeveloped logistics and supply chains. Consequently, coal remains the primary source of fuel for district heating in the medium term, influencing the timing of decommissioning of coal-fired power plants.

3. Basic results of modeling

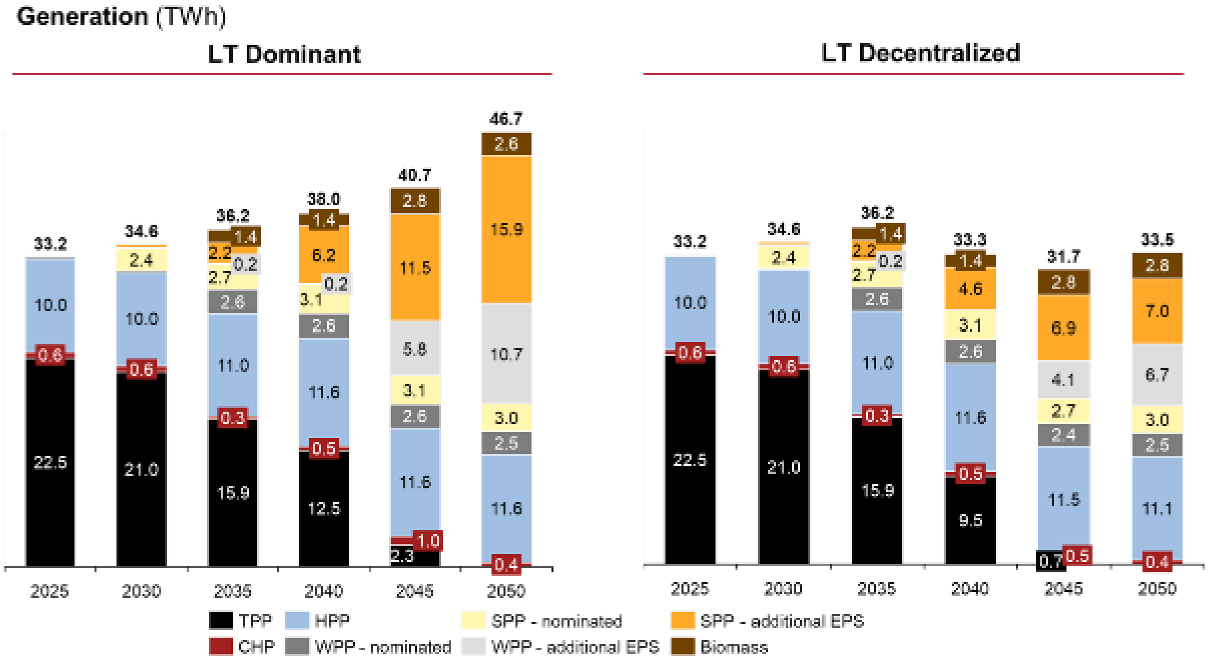
In order to secure future electricity demand, EPS needs to significantly expand its electricity generation capacity, from the current 7.9 GW to 12.6 GW by 2035, and from 2035 in the LT Dominant scenario, it needs to increase to 25.8 GW, while in the LT Decentralized scenario it assumes an increase to 18.2 GW by 2050. Such development requires not only bridging the gap between current and future capacity, but also compensation for coal-fired power plants, of which only 0.7 GW will be retained as a cold reserve.



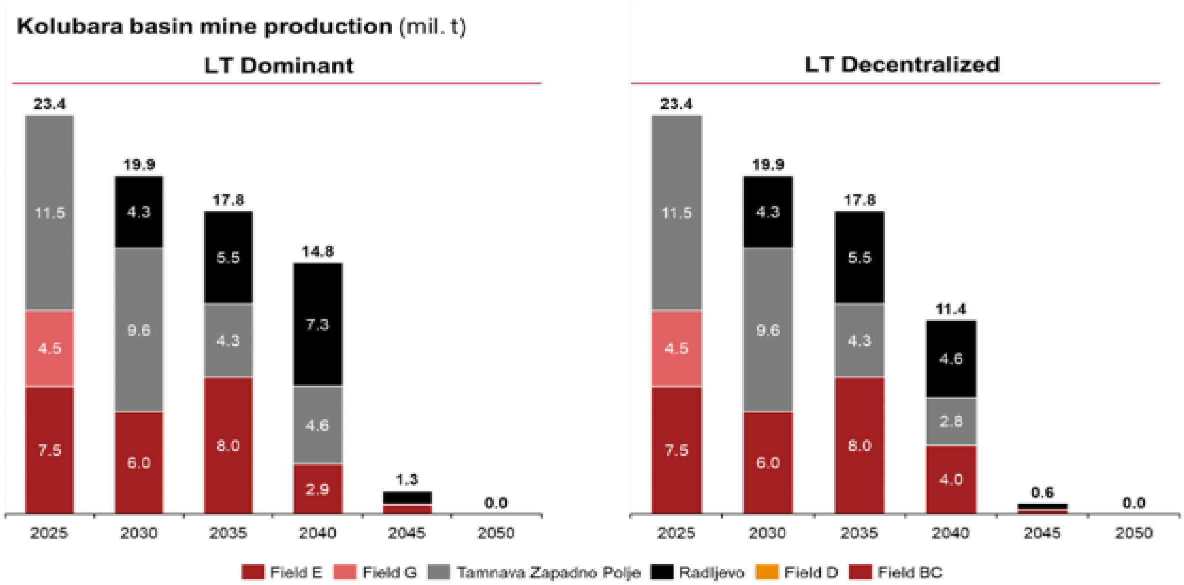
The fastest dynamics for putting new capacities into operation is expected after 2035, with RES gradually displacing the coal-fired power plants. The LT Dominant scenario predicts a sudden increase in RES after 2035, unlike the LT Decentralized scenario where a more moderate increase in RES is assumed and partnerships that will contribute to further advancement of EPS presence in the market. The projected strategic development drives production from RES (wind, solar and hydro) and enables EPS to surpass its production from fossil fuels by 2035.

In LT Dominant scenario, capacity expansion and subsequent increase in production allows EPS to keep its dominant presence in the growing electricity market in Serbia, supplying 88% of national demand by 2050.

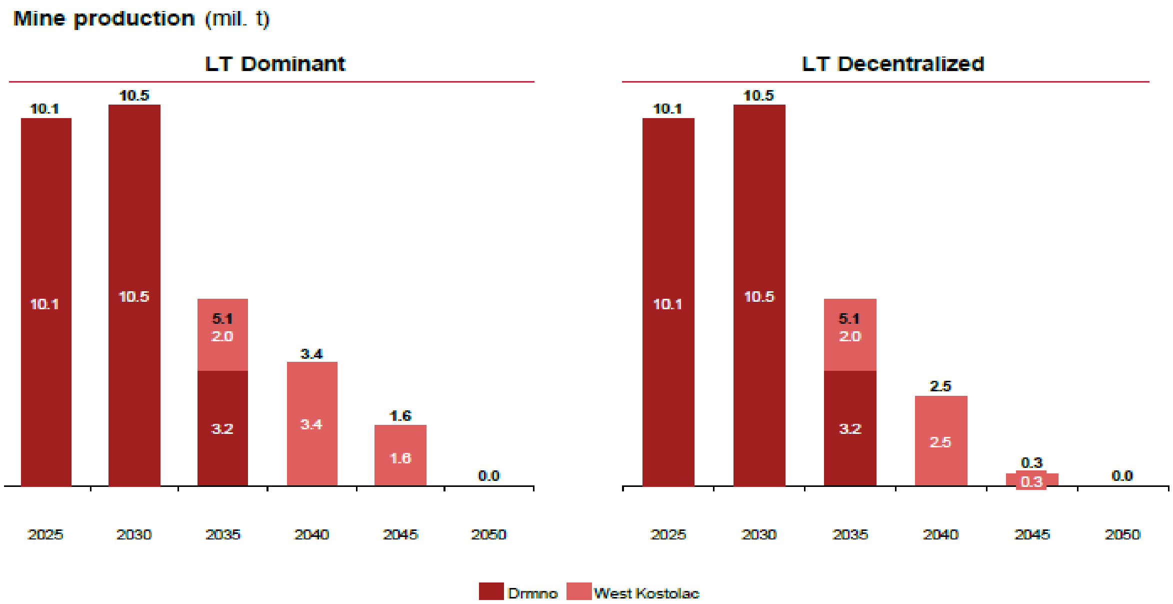
In the LT Decentralized scenario, EPS is expected to cover 63% of national demand, while the remaining 37% will be supplied by other, independent producers (private sector within the partnership with EPS) and an increase in electricity imports. By 2050, in both LT scenarios, renewables are expected to contribute 99% of EPS electricity generation. All thermal power plants should be decommissioned in the period 2046-2049 at the latest, and units Kostolac B2 and B3 will be kept as a cold reserve.



The required lignite production from the Kolubara mine is modeled to cease by 2050, in line with the decommissioning of the thermal units it supplies.



Given that units B2 and B3 in TPP Kostolac are planned to be as the cold reserve, the Kostolac mine cannot be completely closed, so it is necessary to plan that some staff and equipment are kept in case of its activation. Accordingly, the need to open the West Kostolac mine will be analyzed later.



As stated, the basic modeling principle applied is optimization that ensures the lowest cost of electricity generation, while meeting the reliability of the system. In the context of capacity expansion, this translates into prioritizing technologies that offer the most cost-effective contribution to the energy mix over time.

At the beginning of the analyzed period, hydropower is the most cost-effective production technology, followed by wind energy, while gas-fired generation is the most expensive option, which is reflected in its limited role within the current and projected portfolio. Over time, solar energy is becoming competitive due to technological maturity, to become the lowest-cost generation option by 2050. As wind power is already a commercially mature technology, its costs remain relatively stable throughout the modeling period. Taking into account the costs of electricity generation from individual sources, the following diagram shows the projected production costs of EPS for both scenarios.

For evaluating the sensitivity of production costs to CO_2 price assumptions, two cut-off cases have been identified during this critical period:

- CO_2 cost for zero profitability: The EPS production portfolio would become cost-competitive at a CO_2 price of approximately 15 EUR/t in 2030 and 27 EUR/t in 2035, assuming that all other variables and assumptions remain constant as well as the unchanged product portfolio
- No cost for CO_2 emissions: Due to the absence of a cost for CO_2 emissions, the production portfolio would remain fully competitive, with average costs below the projected wholesale market price

4. Decarbonization of EPS – key actions

The successful implementation of this Action Plan is subject to a number of strategic, financial, technical, regulatory and social risks. The scope of the required changes is such that EPS needs to build up to 21.7 GW of new capacities and decommission thermal capacities from operation, while at the same time managing the need for financing.

At the same time, market dynamics are changing rapidly. With the introduction of the Emissions Trading System (ETS) and the Carbon Border Adjustment Mechanism (CBAM) – in addition to the growing importance of climate-aligned supply chains – industrial and commercial customers are less willing to buy carbon-intensive electricity, regardless of its cost. This growing preference may limit EPS's ability to place its electricity on the market, further reinforcing the need to decarbonize the portfolio to ensure long-term commercial viability

Key measures for the decarbonization of the EPS production portfolio by 2050:

- Installing 21.7 GW of renewable capacity in the LT Dominant scenario and 14.1 GW in the LT Decentralized scenario.
- Expanding the capacity of pumped storage hydropower plants (Bistrica and Djerdap 3) to 2.5 GW and add 200 MW of battery capacity to increase flexibility and reliability.
- Gradually decommissioning thermal capacities from operation while keeping strategic reserves in accordance with ENTSO-E standards
- Ensuring the district heat supply (above 10% of the national demand for district heating, if it remains at current levels) through a new gas-fired CHP plant in Novi Sad and alternatively biomass-fired CHP after 2035
- Managing a just transition of the workforce: ~optimization of jobs related to the thermal and mining sector, as well as new posts expected in the RES sector, jobs related to the transmission and distribution network and trading (Initiatives for the acquisition of new skills and reskilling are essential)
- Bridging the decarbonization gap while ensuring a just transition for the workforce, coordinated strategies must be developed between the EPS and relevant state institutions to support Serbia's broader energy transition goals
- Working with the Government and development partners to mitigate the environmental and social consequences of reduced coal exploitation from mines, including land reclamation and support to affected mining communities, based on the best practices of the EU's *Coal Regions in Transition* initiative.
- Ensuring the financial sustainability of EPS, as well as adequate sources for financing (grants, favorable interest rates and other) as a key prerequisite for investing EUR 27.0 billion of estimated CAPEX under the LT Dominant scenario and EUR 22.5 billion under the LT Decentralized scenario
- Taking the opportunity for EPS, through long-term power purchase agreements, joint investments with development partners and other market actors, support based on CO_2 taxes and other available mechanisms, to further provide the estimated investment funds and reduce the financial risks of its operations.