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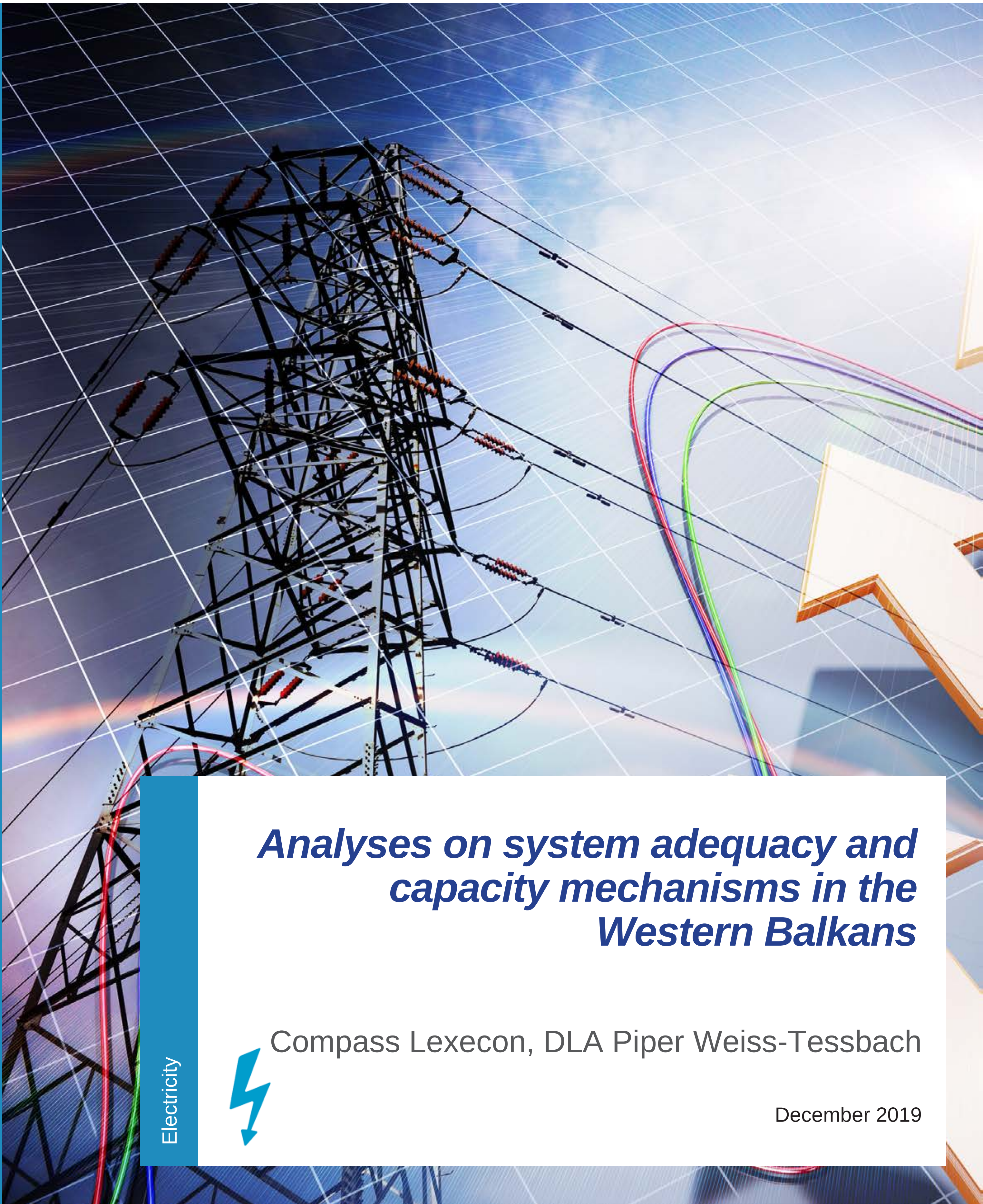

Analyses on system adequacy and capacity mechanisms in the Western Balkans

Compass Lexecon, DLA Piper Weiss-Tessbach

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Electricity

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Foreword

The electricity markets in the Contracting Parties are experiencing a period of complex transition, characterised by the coexistence of the liberalization and decarbonisation agendas. Electricity sector reforms have advanced in the WB6 over the last years. However, the real challenges related to the ageing power plant fleet, implementation of environmental acquis, climate policies, the surge of intermittent electricity generation from renewable energy, etc. are now at the doorstep or already beyond.

Traditionally the region has been well interconnected. Additional investments in cross-zonal capacity combined with national reforms have supported an increase in cross-zonal electricity exchanges over the last few years. The full potential is yet to be exploited and depends on further coordination in capacity calculation, system operation, implementation of cross-border balancing and market coupling. While full integration into the EU internal energy market remains the main objective, the implementation of environmental norms and/or the introduction of carbon pricing schemes will reduce the profitability of some plants and require significant investment. As a consequence, a number of plants could potentially retire, which raises security of supply concerns.

To address this challenge proactively, the Secretariat launched the present study. The results show that an efficient energy-only regional market would bring the flexibility and adequacy required to maintain security of supply. Yet despite all progress, an efficient regional market mechanism is still not in place in the Western Balkans. Beyond delayed reforms, government actions such as non-compliant State aid distort operational and investments signals. Such State aid is often justified by the claim to maintain security of supply, a claim for which the present study in the current conditions does not provide support. In particular, we asked the authors of the study to look into justifications for and modalities of potential capacity mechanisms. Without the energy market reforms completed and a functional and integrated energy-only market in place, there is little room for them.

The adequacy assessment is done using a combination of the market model and the adequacy assessment model, both based on a common set of background assumptions which include the demand forecast, the supply forecast (renewables, hydro, thermal capacity), the cross-border capacity evolution, as well as projections for commodity prices and costs. The modelling was done based on several scenarios combined with different sensitivities. It was interesting to see the impact of the implementation of the EU ETS in WB6 on the power plants' profitability. The study shows that the implementation of an immediate carbon price below the EU ETS would be a good transitional and non-critical measure to mitigate the risk of immediate closure of some of the power plants in the WB6 upon EU accession or the imposition of a carbon border price.

In terms of capacity mechanisms, a well-designed strategic reserve may address short-term adequacy issues and mitigate the closure of some existing plants. On the other hand, a market-wide mechanism would be a more appropriate model to support new investments. Cross-border participation is key and a legal prerequisite for either model in a region that is exceptionally well interconnected. However, this would require additional coordination and a regional framework for security of supply.

We would like to thank our consultants as well as Arben Kllokoqi who coordinated the Secretariat's input to this important milestone towards a design for decarbonized and secure regional energy markets in the Western Balkans.

Energy Community Secretariat

REPORT FOR ENERGY COMMUNITY

Analysis on system adequacy and capacity mechanisms in the Western Balkans

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Glossary

Table 1: Glossary

Abbreviation	Definition
BAT	Best Available Technology
CM	Capacity mechanism
CONE	Cost of New Entry
DSR	Demand side response
EC	European Commission
ECRB	Energy Community Regulatory Body
EENS	Expected energy not served
Energy Only	Energy Only market
ETS	Emissions Trading System
GT	Gas turbine
IED	Industrial Emissions Directive
LCPD	Large Combustion Plants Directive
LOLE	Loss of Load Expectation
RES	Renewable energy source
TSO	Transmission System Operator
VOLL	Value of Lost Load
WB6	Western Balkan Countries - Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia and Serbia

Source: FTI-CL Energy.

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The report is written by Compass Lexecon in collaboration with DLA Piper. Compass Lexecon is generally responsible for economic related issues and more specifically the adequacy assessment analysis and developing possible policy approaches for adequacy. DLA Piper is generally responsible for matters of law and interpretation of regulations, and more specifically the parts of the report providing a description of the evolution of the electricity sector regulation and the existing State aid measures in WB6 Contracting Parties. Compass Lexecon and DLA Piper have reviewed and approved each other's contribution within the limits of their respective expertise but should only be held responsible for their respective contributions. The lead author of this report is Fabien Roques from Compass Lexecon).

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Section 1

Executive Summary

Introduction

1.1 The electricity sector of the Western Balkan countries is currently in transition to be aligned with the European electricity markets and to implement the EU target model for the internal European electricity market.[1] As Contracting Parties of the Energy Community, the Western Balkan countries (WB6) – Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia and Serbia are legally bound to implement the core EU energy legislation, the so-called "*acquis communautaire*".

1.2 The transition towards the EU target model for the internal European electricity market will require a number of adaptations of the power system and will likely modify the revenues of the market operators. For instance, the implementation of environmental norms and/or carbon pricing may reduce the profitability of some plants and require significant investment. As a consequence, a number of plants could potentially retire, raising security of supply concerns.

1.3 The objective of this report is to perform a forward-looking analysis of resource adequacy of the electricity systems of the WB6 Contracting Parties in their transition towards the EU electricity market target model and environmental regulations – that is, to estimate whether sufficient capacity will be available to guarantee security of supplies. Our analysis aims to investigate to what extent the transition toward the EU electricity market target model as well as the implementation of the latest EU environmental requirements and the transition to the CO2 pricing may make existing plants unprofitable to run and cause their decommissioning, which could in turn create adequacy issues.

1.4 This report concludes by assessing possible policy responses to the potential future adequacy issues through implementation of both electricity market reforms as well as policy measures that are focused on the adequacy objective – such as a Capacity Mechanism (CM). We analyse the application of CMs in Europe and identify possible CM approaches for the Western Balkan countries, such as strategic reserves, or a market-wide capacity market. We finally provide some insights into the key implementation issues of such capacity mechanisms based on the lessons from those implemented in Europe.

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1 A set of regulations, guidelines and network codes defining the target design of electricity markets organized on a zonal basis with facilitated border-free trading across Europe.

Evolution of the electricity market regulation in WB6 Contracting Parties

1.5 Despite significant progress in the past years, the current electricity sector organization in the WB6 Contracting Parties still represents an incomplete stage of liberalization. To align with European regulations on the electricity sector, WB6 Contracting Parties have made and will need to make further progress in three areas:

- **Reform of the WB6 electricity markets towards the EU target model.** On the one hand, the electricity sector of WB6 Contracting Parties is evolving and timelines for introduction of organised power exchanges and market coupling have been set. However, a number of elements of the market design still remain to be addressed, such as the lack of balancing and ancillary services markets, and the presence of certain regulated prices in the wholesale and retail markets, as well as the integration of demand side response (DSR). On the other hand, the regulated share of the market remains substantial. Between 50% and 90% of volumes generated by incumbents in the WB6 Contracting Parties are reserved for the suppliers of regulated customers. The volumes traded by market participants on the free wholesale market represent mainly the cross-border trade to sell incumbents' surplus or procure volumes to cover shortages for incumbents or network losses.

- **State aid interventions in the WB6 electricity sector.** The WB6 electricity sector is still characterised by a significant involvement of the state in the form of subsidies and State aid. Plants in operation and investment in generation capacity in electricity markets in the WB6 Contracting Parties is affected by direct or indirect subsidies or other forms of state support that determine incentives to invest in capacity and which often provide revenues to investors through channels other than market prices. Investors in capacity receive subsidies or other forms of state support to cover or mitigate both costs of operation and costs of investment in capacity, directly or indirectly.[2] Coal and lignite for instance remain more supported than renewables in WB6 Contracting Parties.[3] Compliance with European State aid regulation may require either phasing out these measures or converting them into measures compliant with State aid regulation.

- **Implementation of European environmental legislation.** Pursuant to the Energy Community law and EU accession context, the WB6 Contracting Parties need to apply the EU environmental regulation in the electricity sector – including in the future emission norms for power plants and carbon pricing. The WB6 Contracting Parties have to comply for instance with specific rules of the Large Combustion Plants Directive (LCPD) and the Industrial Emissions Directive (IED) adapted to the specific situation of the Energy Community Contracting Parties. The WB6 Contracting Parties are also likely to be required to introduce an emission trading system for the Energy Community, similar to the one

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2 See section on specific remuneration mechanisms for investment in generation capacity in the WB6 Contracting Parties.

3 For a quantification, see the Energy Community Study on subsidies to coal.

existing at the EU level, or another form of carbon pricing. One of the provisions of the new Electricity Regulation 2019/943 ('Electricity Regulation') is a new emission limit of 550 grams of CO2 of fossil-fuel origin per kWh of electricity as an eligibility condition for participation in capacity mechanisms.

Adequacy outlook in WB6 Contracting Parties with implementation of EU electricity target model and environmental legislation

1.6 Implementation of reforms to further align with the European regulation of the electricity sector could negatively impact the adequacy of the electricity system of WB6, that is, its ability to meet peak demand. This is because EU environmental regulation (carbon pricing, emission directives) could significantly affect the profitability of existing thermal plants and the incentives for new capacity investment, leading to closures or cancelled investment decisions.

1.7 We assess the extent to which these reforms may impact the future security of supply of the WB6 power markets by conducting a forward adequacy assessment, using a detailed model of the WB6 electricity markets and neighbouring countries (the 'Market Model') as well as a probabilistic analysis of the WB6 power system supply and demand ('the Adequacy assessment model').

1.8 The forward adequacy assessment is made by combining the Market model and Adequacy assessment model, which are both based on a common set of background assumptions. These include supply and demand forecasts, (renewables, hydro, thermal capacity), cross-border capacity development, as well as projections for commodities and costs:

- **The Market model** assesses the wholesale electricity price based on the marginal value of energy. The simulated power price and generation volumes are then used to determine the net present value (NPV) of future revenues and costs, and thus to derive investment and shutdown decisions. We then simulate decisions for investment and shutdown based on the NPV calculation (e.g. new plants are not built if their NPV is negative). The market model enables us to derive the capacity outlook based on an economic equilibrium.

- **The Adequacy assessment model** studies whether the future expected installed capacity would be enough to meet the security of supply target. For a given capacity outlook derived from the Market model, the Adequacy model assesses the level of security of supply accounting for risks and uncertainties related to demand sensitivity to temperature, the availability of thermal plants or the availability of renewable production (wind, solar, hydro) through probabilistic simulations (e.g. Monte-Carlo simulations).

1.9 We assess the impact of reforms on resource adequacy by considering and comparing several scenarios. In all assessed scenarios, we assume that (i) the EU target model is implemented in the WB6 region (i.e. fully competitive power markets, with market-coupling) and (ii) current State aids are phased-out (no complementary source of revenue beyond electricity market revenue and unsubsidised fuel prices). Further, to assess the impact of possible future environmental reforms (i.e. carbon pricing and implementation of LCPD and IED environmental norms) on adequacy, we model and compare the outcomes of the following scenarios:

- **TSOs Base Case scenario -** based on TSOs' base case scenarios for forecast of capacity additions and retirements. Contrary to the scenarios presented below, long-term decisions regarding investments and closures are inputs to the model and are not estimated based on the Market model. Moreover, the Base Case scenario assumes that WB6 Contracting Parties do not apply a carbon price or enter the EU ETS market. Finally, this scenario does not consider the full impact of environmental norms (LCPD and IED).[4]

- **Energy Only market scenarios** – considering that the decisions for capacity retirement, investments and refurbishment are "merchant-based", that is, made if their expected net present value from the power market revenues is positive. The energy only scenarios consider that existing power plants need to comply with environmental norms (LCPD and IED) and to refurbish by 2023 for the LCPD and by 2028 for the IED. Contrary to the Base Case scenario, we assume that power plants are subject to a CO2 price. We distinguish two scenarios depending on when CO2 pricing starts to be implemented:[5]

  – the EU ETS 2030 Energy Only scenario, in which WB6 Contracting Parties enter the EU ETS market from 2030 onwards.

  – the EU ETS 2025 Energy Only scenario, in which WB6 Contracting Parties enter the EU ETS market from 2025 onwards.

1.10 In addition to the Base Case and the Energy Only market scenarios, we consider several sensitivities to assess the incremental impact of different elements of the reforms on adequacy, in particular, the transitional introduction of the CO2 price and the efficiency of market coupling:

- **Sensitivity of transitional CO2 price between 2025 and 2029.** Implementation of EU ETS in the WB6 Contracting Parties is expected to have a significant impact on the profitability of existing lignite plants. To assess the extent to which lignite plants economics would be impacted by a different carbon price, we perform a sensitivity analysis by considering that WB6 Contracting Parties apply a transitional CO2 price between 2025 and 2029. This sensitivity provides insights on the transitory CO2 price in the WB6 region that would allow maintaining sufficient lignite plant capacity and adequacy levels (considering that the WB6 Contracting Parties enter the EU ETS market in 2030 in all cases).

- **Market coupling efficiency sensitivity.** Given the importance of cross-border exchanges for the WB6 Contracting Parties, we perform a sensitivity analysis of the EU ETS 2025 and

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4 Apart from power plants which decided to opt out from the LCPD and which are considered to close by 2023, forecasts made by TSOs do not assess the impact of LCPD on profitability of other plants and, more importantly, the impact of IED limits.

5 For transparency of the modelling results, we consider that in these scenarios the CO2 price is fully phased in one year. In Section 5 we discuss possible transitional schemes for the gradual introduction of CO2 pricing.

2030 Energy Only scenarios by limiting the import volume from neighbouring countries, which mimics a potential inefficient use of cross-border capacity within WB6 Contracting Parties and with neighbouring countries. This provides useful insights on how the adequacy outlook may depend on the efficiency of the market coupling.

Investment decisions for the new and existing plants in the Energy Only scenario

1.11 The analysis of the investment decisions in the Energy Only scenario in comparison with the Base Case scenario provides insights on the potential impact of the combined implementation of the different reforms described before (including the environmental norms and carbon pricing):

- **Existing plants.** Complying with LCPD by 2023 and IED by 2028 would require existing thermal plants to refurbish and invest additional annualised CAPEX of 15€/kW to meet LCPD and 30€/kW to meet IED. A full exposure to carbon pricing through the EU ETS would make refurbishment investments to comply with LCPD and IED unprofitable, leading to closure of more than half of the existing lignite capacity by 2030 compared with the Base Case scenario (4.4 GW).

- **New plant investment decisions.** Full implementation of the EU ETS carbon price (in 2025 or in 2030 according to the scenario) would also weaken the economics of new carbon-intensive lignite plants. As soon as carbon pricing is introduced through the EU ETS, new lignite plant investments would become unprofitable and would not be realized: 2.8 GW of new lignite projects are cancelled compared with the Base Case scenario.

1.12 As a result, WB6 lignite capacity would fall in total by 7.2GW in 2030 compared with the Base Case scenario, which would break down into 2.8GW of cancelled new investments, and 4.4GW of anticipated closures in late 2023 or late 2027 to comply with LCPD or IED.

Impact on security of supply

1.13 The gap of future investments in both new and existing plants in the EU ETS 2030 Energy Only scenario and to a larger extent in the EU ETS 2025 Energy Only scenario would affect the future security of supply of WB6 power markets.

1.14 We find that in the Energy Only scenario, the number of hours of load curtailment per year (Loss of Load Expectation, or LOLE) would largely increase as compared with the Base Case scenario by 2025-2030. This is especially so for Serbia and Albania, where the LOLE will be significantly above a typical target level of LOLE of 6-8 hours per year:

- The challenging situation of Serbia is explained by the significant number of (i) cancelled new projects and (ii) closures due to adverse economic conditions impeding refurbishment, which, combined, can threaten security of supply as soon as 2025 in the EU ETS 2025 Energy Only scenario, and in 2030 in the EU ETS 2030 Energy Only scenario.

- In Albania, adequacy issues can occur when hydro availability is limited, given the importance of hydro for the Albanian system. Cancelled projects and lignite closures in foreign countries worsen this situation by reducing the contribution of imports for Albania.

Sensitivity of results to CO2 price

1.15 The modelling results suggest that the limited new investments and anticipated plant closures are highly dependent on the date of the full phase-in of the CO2 price through the implementation of a carbon pricing mechanism at the level of the EU ETS carbon price. In the CO2 sensitivity analysis, we assess to what extent a gradual introduction of such a CO2 price in the WB6 Contracting Parties could mitigate the impact on power plant closures. More precisely, we explore the extent to which a transitional CO2 pricing regime in WB6 Contracting Parties between 2025 and 2029 could mitigate some of the effects identified above on the adequacy outlook (assuming that the WB6 region ultimately enters the EU ETS scheme in 2030).

1.16 Note that we do not comment on the feasibility and/or implementation issues associated with such a transitional CO2 pricing regime, which are left for further research. In practice, a reduced 'effective CO2 price' for the WB6 Contracting Parties could be implemented through different approaches, including a gradually rising tax, and/or emissions trading implementation together with compensation policies, such as exemptions as well as investment support policies.

1.17 We find that in order for refurbishments required to comply with LCPD norms to be economic for the existing plants mitigating anticipated closures by late 2023, the transitional CO2 price in the W6 region could be set up to 13-14€/tCO2 between 2025 and 2027, below the EU ETS CO2 price assumed to be 22.5€/tCO2 in 2025. This transitional CO2 price would improve the likely adequacy issues in 2025.

1.18 However, given that the WB6 region is assumed to ultimately enter the EU ETS scheme in 2030, having a relatively low transitional price in 2028 and 2029 would not encourage investment in refurbishment to comply with IED since these costs must be recovered over 10 years. Consequently, the CO2 price in the WB6 region can increase from 2028 onwards to reach the EU ETS level in 2030 (assumed equal to 30€/tCO2). Having a transitional CO2 price in 2028 and 2029 would not help prevent decommissioning because of the IED limits. The adequacy issues observed in 2030 in the Energy Only scenarios are thus also likely to occur in the CO2 sensitivity scenario.

Sensitivity of results to cross-border interconnection with neighbouring countries

1.19 The high degree of interconnection and the future implementation of market coupling will create significant interdependency between the WB6 Contracting Parties and with neighbouring countries. In particular, following the introduction of carbon pricing and the closures of several plants, the WB6 region will start relying on imports to meet its demand. Reduced imports from neighbouring countries, due to inefficient market coupling, can then impact the situation in the WB6 region. Hence, we perform a sensitivity analysis of the EU ETS 2025 and 2030 Energy Only scenarios by limiting the import volume from neighbouring countries, which mimics a potential inefficient use of cross-border capacity in the absence of /or imperfect implementation of market coupling.

1.20 Inefficient use of import capacity with neighbouring countries would tend to increase power prices in the WB6 region since more expensive plants would be necessary to satisfy WB6 power demand. As a result, the economic situation of the remaining lignite plants would slightly improved compared with the previous unconstrained scenarios and fewer plants would be decommissioned (3.9 GW would be closed by 2030 as compared with 4.4 GW in the unconstrained scenario). However, as in the Energy Only scenarios, new planned projects would still be unprofitable, even with limited imports.

1.21 Inefficient market coupling with neighbouring countries would lead to an inefficient power system for the WB6 region: it would require more expensive WB6 plants to be available and to produce to meet the peak demand in WB6 Contracting Parties. As a result, it would increase total costs for consumers. Moreover, it may create greater challenges for adequacy since WB6 Contracting Parties are highly dependent on imports during scarcity events.

Policy approaches to address the potential adequacy problem in WB6 Contracting Parties

1.22 The previous section showed that potential adequacy issues in WB6 Contracting Parties could arise as a result of the implementation of the EU Target Model for electricity, phasing out of existing State aid and transposing the environmental policies in the WB6 Contracting Parties (e.g. CO2 price and LCPD / IED emission norms). The objective of this section is to explore the policy approaches that could be considered to ensure adequacy during this transition, applying measures such as capacity mechanisms.

1.23 We stress that the policies considered in this section are no substitute for the implementation of sound market design and the continuation of market reforms which should be a priority focus in WB6 Contracting Parties; the policies discussed below are meant to complement the policies aiming at reforming the market with the objective of ensuring adequacy in the transition.

1.24 In the short to medium term, the transition toward a new market framework could lead to temporary adequacy issues as a result of the retirements of some plants which could become uneconomic to run, given the lead times necessary for new investments. Policies aiming at managing the transition effects should therefore concentrate on existing units and manage the pace of closures to ensure adequacy.

1.25 In the medium to long term, once these reforms are implemented, investors and operators of power plants would primarily rely on the market prices of electricity that are formed in a competitive way reflecting the efficient use of the available interconnection capacity.

1.26 Therefore, State aid measures ensuring security of supply could be considered in WB6 Contracting Parties in the transition towards the implementation of the market reforms. Such measures need to be tailored to the specific issues and characteristics of the WB6 power systems, such as the reliance on existing lignite capacity requiring refurbishment to comply with EU environmental norms and the interdependency between WB6 power systems.

1.27 The new EU regulation defines Strategic Reserves as a temporary CM solution to prevent decommissioning of existing capacity and a Market-Wide CM in case there is a long-term need to induce new capacity. Given the adequacy issues of the WB6 Contracting Parties, both high-level CM models could be considered in WB6 Contracting Parties:

- A **Strategic Reserve** model appears as a suitable first option for WB6 Contracting Parties to maintain generation capacity needed for adequacy in the transition to European regulation of the electricity sector. This model could be a viable transitory solution until the emission performance standard of 550gCO2/kWh is transposed in WB6 Contracting Parties and excludes the existing lignite and coal plants from capacity mechanisms. Until this moment, the existing plants that are at risk of decommissioning according to the adequacy analysis, could participate in a Strategic Reserve.

- A **Market-Wide capacity mechanism model** could be an alternative for WB6 Contracting Parties in case maintaining adequacy would require support to trigger investment in new capacity and/or refurbishing existing units after the 550 rule is transposed in WB6 Contracting Parties. In a market-wide mechanism, all capacity required to ensure security of supply receives payment, including both existing and new providers of capacity. These mechanisms are in general technologically neutral and they are open for participation to all capacity resources contributing to adequacy, including DSR and RES, as long as these capacity resources meet the CO2 emission performance standard.

1.28 Given the high interdependency between WB6 Contracting Parties, the efficiency of both the Strategic Reserve and Market-Wide mechanisms may require that capacity resources from across the border participate in a national or a regional CM. The new Electricity Regulation confirms the need to introduce cross-border participation in the new CMs. Cross-border participation would require a number of political decisions and coordination among political decision-makers, regulators and TSOs to develop a regional framework for security of supply: (i) between TSOs on reliability standards assessment; (ii) between national authorities and TSOs on regional policy, legal and operation framework; (iii) between TSOs on cross-border arrangements.

Key implementation issues for capacity mechanisms

1.29 We then discuss the key high-level design choices and implementation issues associated with the different types of capacity mechanisms described in the previous paragraphs.

1.30 Considering the CMs as State aid, the European Commission (EC) sets a framework to evaluate their appropriateness and provides recommendations for their design. The framework includes three main categories of criteria: (i) justification for the measure, (ii) design of the different elements of the measure, and (iii) potential impact of the measure on competition and the internal market.

1.31 Once Member States have assessed their adequacy outlook and decided to introduce one capacity mechanism, they face a range of choices to design a suitable capacity mechanism to address the identified adequacy problem. There are a number of considerations to be made in accordance with the specificities of the individual electricity markets. The most important of those design choices include:

i. who gets to participate in the capacity mechanism;

ii. how the selection process among the eligible parties works and how the level of capacity remuneration is determined; and

iii. what participants in the scheme have to do, and what happens if they don't do it.

1.32 For each of those design features, we provide examples of best practice from existing European capacity mechanisms for the two CM models considered for the WB6 Contracting Parties: market-wide capacity mechanism and Strategic Reserve.

1.33 Moreover, for both CM models, the EU Regulation requires that foreign capacity providers can explicitly participate in national capacity mechanisms and receive capacity revenues. Although these cross-border arrangements are still under development, the principles of such arrangements include:

- calculation of the capacity requirement for each zone to meet the reliability standard based on adequacy analysis;
- assessment of the volume of transmission import capacity that can contribute to the capacity requirement accounting for coincident stress events between the market zones;
- organisation of a pre-auction to pre-select foreign capacity for participation in national capacity auctions; and
- allocation of the congestion rent arising when the supply of foreign capacity exceeds the entry capacity of the given interconnector.

1.34 A further step in the regional coordination of capacity mechanisms could be a mechanism of joint capacity allocation consisting of setting individual capacity requirements in different zones and simultaneously solving all requirements in a single auction taking into account the contribution of transmission capacity and setting different capacity prices across bidding zones in case transmission capacity is binding.

1.35 Implementation of such a regional CM would require a different level of coordination between TSOs with respect to synchronisation of the auctions and having a regional body for running the regional auction.

Section 2

Introduction

Context: transition issues as WB6 Contracting Parties liberalise electricity markets

2.1 As Contracting Parties of the Energy Community, the Western Balkan countries (WB6) – Albania, Bosnia and Herzegovina, Kosovo,* Montenegro, North Macedonia and Serbia are legally bound to implement the core EU energy legislation, the so-called "*acquis communautaire*”. In particular, all WB6 Contracting Parties have transposed the Third Energy Package into their national legislation, with the exception of Bosnia and Herzegovina. In this context, the electricity sector of the Western Balkan countries is currently in the process of transitioning to be aligned with the European electricity markets and to implement the EU target model for internal European electricity market through the Energy Community. Ukraine, Moldova and Georgia are also Contracting Parties to the Energy Community. However, this study covers only the WB6 Contracting Parties.

2.2 The current electricity sector organization in the WB6 Contracting Parties represents an incomplete stage of liberalisation of the wholesale market. On the one hand, the sector has started to be shaped by the ongoing reforms (e.g. market coupling, etc.), but on the other hand, it is still characterised by a significant involvement of the state (ownership, regulation, subsidies, State aid, etc.). Currently, the regulated share (mainly under the PSO framework) of the market remains substantial, and 50% to 90% of volumes generated by incumbent utilities in the WB6 are reserved for the suppliers of regulated customers. The volumes traded by market participants on the free wholesale market represent mainly the cross-border trade to sell incumbents’ surplus, or procure volumes to cover shortages for incumbents, or network losses.

2.3 As a condition for the EU accession, the Balkan countries would also eventually need to apply the EU environmental regulation in the electricity sector, including emission norms for power plants and carbon pricing. The WB6 Contracting Parties must already now comply with the Large Combustion Plants Directive (LCPD) and the Industrial Emissions Directive (IED) as adapted to the specific situation of the Energy Community Contracting Parties. To meet the IED emission values for new plants, WB6 Contracting Parties must also implement Chapter II of the IED on the use of Best Available Techniques (BAT) established by the European Commission.

2.4 Besides, the accession process and an increasing awareness within the EU about carbon leakage through non-carbon priced electricity imports may also push the WB6 towards the introduction of a carbon pricing scheme including the framework for collection of GHG emissions data linked to the one existing at the EU level. Although a carbon pricing mechanism currently exists only in Montenegro, progress has been made in terms of greenhouse gases (GHG) reporting and monitoring. In addition, WB6 Contracting Parties, except Kosovo* have ratified the Paris Agreement and developed their Nationally Determined Contributions (NDCs). Kosovo too is developing an energy strategy in which it addresses emission reductions.

2.5 In June 2019, the European Commission adopted an updated Electricity Regulation 2019/943 (‘Electricity Regulation’), as part of its Clean Energy Package. The Electricity Regulation is not part of the Energy Community acquis yet but is expected to be incorporated by 2020. One of the provisions of the new Electricity Regulation is a new eligibility condition for participation in capacity mechanisms based on CO2 emission limits. This condition excludes new installations emitting more than 550g of CO2 per kWh of electricity. From July 2025, this condition excludes the existing installations emitting more than 550g of CO2 per kWh and 350kg of CO2 on average per year per KW of installed capacity.

Objectives of this report: Investigate possible adequacy issues associated with implementation of EU environmental regulation

2.6 The application of the EU environmental regulation accompanied by removal of some existing state intervention and introduction of electricity market reform, including CO2 pricing, may have a significant impact on the profitability of the existing power plants in WB6.

2.7 The objective of this report is to perform the analysis of adequacy of the electricity systems of the WB6 Contracting Parties in their transition towards the EU regulation. Our analysis suggests that environmental requirements and the transition to the CO2 pricing may make a number of existing plants unprofitable to run and cause their decommissioning, which could in turn create adequacy issues in the Balkan countries.

2.8 In this report we assess possible solutions to the potential future adequacy issues through implementation of the State aid measures that are focused on the adequacy objective – a Capacity Mechanism (CM). We analyse the application of CMs in Europe and detail several possible high-level CM solutions for the Western Balkan countries, such as strategic reserves and a market-wide capacity market. We further examine the implementation of such mechanisms in Europe.

Structure of this report

2.9 The report is written by Compass Lexecon in collaboration with DLA Piper. Compass Lexecon and DLA Piper have reviewed and approved each other’s contribution. The structure of the report and separation of responsibilities between Compass Lexecon and DLA Piper are as follows:

- DLA Piper is generally responsible for matters of law and interpretation of regulation. More specifically, DLA Piper provides a description of the evolution of the electricity sector regulation in WB6 and the existing State aid in Section 3 and further details in Appendix D and Appendix E.

- Compass Lexecon is responsible for the issues related to power market modelling and economic analysis of CRM design. More specifically, Compass Lexecon provided the adequacy assessment analysis and developing policy approaches in Section 4, Section 5 and Section 6, and further details of the adequacy assessment, assumptions, modelling framework and results of the adequacy assessment in Appendix A, Appendix B, and Appendix C.

Section 3

Evolution of electricity market regulation in WB6 Contracting Parties

Introduction

3.1 This section written by DLA Piper describes the process of the evolution of the electricity market regulation in WB6 Contracting Parties to align with European regulation. It relies on the detailed country-specific information collected by the consultancy team and presented in Appendix D. In particular, we discuss:

- The evolution of the WB6 electricity markets towards the EU target model;
- The evolution of the State aid interventions in the WB6 electricity sector; and
- The state of implementation of European environmental legislation.

Evolution of the WB6 electricity markets towards EU target model

3.2 Below we present an overview of the evolution of the electricity markets in the WB6 Contracting Parties towards the target model of the internal European electricity market, in particular, the wholesale markets, the balancing and ancillary services markets, as well as market-based rather than regulated wholesale and retail prices, as well as DSR development. We also present the regional cooperation process among WB6 Contracting Parties in the electricity market.

Wholesale electricity markets

3.3 Currently, 50% to 90% of energy volume generated by incumbents in the WB6 is reserved for the supplier of regulated customers. Most of the volumes traded by market participants on the free wholesale market represent cross-border trade to sell incumbents' surplus or procure volumes to cover shortages for incumbents or network losses. There is limited market liquidity in the absence of organised spot and forward markets, except for the organised power exchange SEEPEX in Serbia.

3.4 WB6 Contracting Parties have agreed to implement the EU Target model through the Energy Community. Market integration is the key objective, encompassing both the Contracting

Parties and EU Member States. In 2003,[6] CEER proposed a Standard Market Design for SEE[7] which was endorsed by the EU Commission in its Consultation Note.[8] CEER adopted a Discussion Paper[9] towards the implementation of the target model in which it incorporated both a phased approach developed by the Commission and the harmonized approach suggested by CEER.[10]

3.5 Below are listed the key planned reforms which are expected to establish a competitive electricity market and comply with the EU target model.

Organised markets development

3.6 The WB6 Contracting Parties are required to adopt a legal and regulatory framework that would:

- provide for a new market model including operation of an organized electricity market, i.e. with day-ahead and intraday markets, and develop rules for their operation;[11]
- abolish discriminatory barriers to market participation and market activity for an organized electricity market;[12] and
- abandon potential barriers to the operation of clearing and settlement processes by foreign entities.[13]

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6 Prior to the signature of the Energy Community Treaty.

7 CEER Position Paper, Standard Market Design of the SE Europe Electricity Market Basic Principle, 2003.

8 European Commission, DG TREN, Discussion and Consultation Note, The Regional Energy Market in South East Europe and its Integration into the European Community's Internal Energy Market, the Athens Forum, 3-4.06.2004. In this document, the European Commission developed a phased approach of the national reforms that were to take place in each of the SEE countries.

9 CEER Working group Southeast European Electricity Regulation: Discussion Paper on the Options for the Transition Phase of SEE Regional Electricity Market, 16.11.2004.

10 See Policy Guidelines by the Energy Community Secretariat on increasing Competition and Liquidity of Wholesale Electricity Markets, including Power Exchanges, PG 01/2019 / 08 May 2019.

11 This also involved defining whether the operation of an organized market is treated as a monopoly or a competitive business, and whether a merchant, cost of service or hybrid model PX is chosen, as well as identifying conditions for obtaining the PX license, and deciding whether the number of PX licenses is limited or not; see Policy Guidelines by the Energy Community Secretariat.

12 See Policy Guidelines 03/15 on the Promotion of Organised Electricity Markets in the Contracting Parties developed and published by the Energy Community Secretariat.

13 See Policy Guidelines by the Energy Community Secretariat on increasing Competition and Liquidity of Wholesale Electricity Markets, including Power Exchanges, PG 01/2019 / 08 May 2019.

3.7 WB6 Contracting Parties have opted for establishing national organised electricity markets, save Kosovo* which has opted to be serviced by the Albanian PX. This first involved the establishment of day-ahead markets and then intraday segments. These national organised electricity markets should be coupled at a subsequent stage.

Market coupling

3.8 WB6 Contracting Parties are expected to provide a framework for the harmonisation of single day-ahead and intraday market coupling, in order to ensure efficient capacity allocation and congestion management, increasing the competitiveness and utilisation of cross-zonal capacity.

3.9 The EU Regulation 2015/1222 establishing a guideline on the capacity allocation and congestion management ('**CACM Regulation'**) is not yet part of the Energy Community acquis, but is expected to be incorporated in the near future.[14]

3.10 Through the WB6 process, the WB6 Contracting Parties committed to establish and couple their day-ahead markets by July 2018, however, this process was delayed. The Energy Community Secretariat is working closely with the relevant stakeholders in defininng the roadmap for several market coupling projects in WB6 and future coupling with EU Member States.

3.11 The Energy Community Regulatory Board (ECRB) is working on developing a harmonised regulatory framework for the early implementation of CACM related to day-ahead market coupling and for the process for establishing the *so-called 'Shadow Capacity Calculation Region 10*' comprising WB6 and its neighboring EU Member States). A draft methodology for coordinated capacity calculation is developed under the WB6 regional energy market connectivity programme.[15]

3.12 Based on the already binding EU Regulation 714/2009,[16] WB6 Contracting Parties are expected to implement implicit allocation of cross-zonal capacity by way of market coupling, as an alternative to explicit allocation,[17] allowing the pilot projects to go live before implementation of the CACM Regulation.

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14 Preparatory works have started in WB6 Contracting Parties for its prospective transposition and implementation.

15 Recommendation of the Energy Community Regulatory Board on regulatory measures supporting early implementation of day-ahead market coupling in the Energy Community Contracting Parties.

16 EU Regulation 714/2009, which sets the basic principles for integrated cross-border markets and triggers the development of network codes and guidelines in form of Regulations, is already binding and part of the Energy Community acquis on WB6 Contracting Parties.

17 On the EU level, most of the EU Member States already implemented market coupling mechanisms well before the CACM Regulation entered into force, under the framework of EU Regulation 714/2009 with

3.13 ECRB has issued a note on the early implementation of NEMO designation process in line with in the CACM Regulation, finding one or more electricity market operators to service the national market.[18]

3.14 In parallel, WB6 Contracting Parties are expected to eliminate obstacles to market coupling such as absence of VAT harmonization, and ensure compliance with the Third Energy Package. Most of the countries have made progress in this regard, save Bosnia and Herzegovina.

3.15 All WB6 Contracting Parties, save Serbia, participate in the Coordinated Auction Office in South East Europe (SEE CAO) providing for regionally coordinated capacity allocation. Specific market coupling plans include:

- By September 2020, potential market coupling of Albania with Italy, Montenegro, Serbia;
- By the second half of 2020, potential market coupling between Kosovo* and Albania. Two Memorandums of Understanding have been signed by the relevant ministries of the two countries. In the second half of 2018, a Memorandum of Understanding on market coupling was signed by the national regulators and TSOs.
- By end 2019, potential market coupling between Italy and Montenegro. Construction works for the interconnector have been successfully completed, and its official commissioning took place in November 2019.[19]
- By January 2020, potential market coupling between North Macedonia and Bulgaria. This project is launched, however, there is no publicly available information on the timeline or the roadmap.[20]
- A Memorandum of Understanding was signed between the North Macedonia MEPSO, IBEX and the Bulgarian Electricity System Operator (ESO), on coupling of the day-ahead markets of the two countries.[21] In March 2019, MEPSO, ESO EAD-Bulgaria, and the Albanian TSO signed a MoU on day-ahead market coupling between the three countries,

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the approval of national regulatory authorities. See Recommendation of the Energy Community Regulatory Board on regulatory measures supporting early implementation of day-ahead market coupling in the Energy Community Contracting Parties.

18 WB6 Contracting Parties are advised to consider upfront whether their national newly established PXs would fulfil such criteria and whether they would be suitable for performing NEMO functions.

19 https://balkaninsight.com/2019/11/15/montenegro-italy-turn-on-undersea-power-cable/

20 https://sitel.com.mk/bekteshi-novata-strategija-za-energetika-do-2040-se-potpira-na-pette-stolba-na-evropskata-energetska

21 http://www.ibex.bg/en/announcements/news/bulgaria-and-macedonia-signed-a-memorandum-for-coupling-of-the-day-ahead-markets.html

accompanied by an implicit capacity allocation in accordance with the European target model.[22]

3.16 Timing is based on the initial plans of the stakeholders involved, however considering the current state of development, the timing of all planned market coupling projects will need to be adjusted.

Balancing and ancillary services

3.17 Currently, balancing markets in WB6 Contracting Parties are to a high degree regulated, with the exception of Bosnia and Herzegovina, and Montenegro. Even in these two countries, there are still elements of regulatory constraint. There is almost no cross-border provision of balancing services (save for Bosnia and Herzegovina), resulting in quasi-isolated national balancing markets with high dominance of the incumbents.

3.18 The Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing ('**EB GL**') and Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation ('**SO G**L').[23] are not yet part of the Energy Community acquis; but this is expected to be incorporated in the near future. WB6 Contracting Parties are however invited to take measures through early implementation of the EB GL and SO GL.

3.19 This implies, in particular, phasing out regulated prices or highly restrictive price caps in the balancing markets; implementation of market-based procurement of balancing capacity and balancing energy; and implementation of cross-border procurement of balancing services. Some of the WB6 Contracting Parties have taken certain steps for the transposition of certain articles of the EB GL or SO GL, with respect to both national balancing market and cross-border balancing. However, this reform is at an initial stage.

Market-based prices

3.20 Most WB6 Contracting Parties have formally abolished regulation of wholesale power prices. However, induced by the low level of regulated retail prices, most state-controlled generators seem to set wholesale prices for electricity volumes reserved for the supply of regulated customers for sales within intra-group or the retail public supplier (50%-90%) on a non-market based level. At retail level, public suppliers or the intra-group unit dedicated to the public supply of regulated customers typically cross-subsidize prices for regulated customers by setting

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22 https://balkaneu.com/energy-operators-of-bulgaria-north-macedonia-albania-sign-mou-on-energy-market-in-see/

23 Ongoing technical assistance for the Implementation of Cross-border Balancing, in the framework of the connectivity program, is supporting WB6 Contracting Parties in this task.

higher prices for deregulated large customers (i.e. part of the costs for regulated customers are passed through to deregulated large customers).[24]

3.21 The Third Package and acquis on State aid require WB6 Contracting Parties to phase out non-compliant subsidisation[25] and price regulation.[26] However, some of the WB6 Contracting Parties seem to maintain subsidization and regulated prices at retail level, and to some extent in implied ways at wholesale level.[27]

DSR development

3.22 According to the Energy Efficiency Directive (2012/27/EU) (Article 15), WB6 Contracting Parties should encourage demand response to participate alongside supply within the wholesale and balancing markets*.* TSOs and DSOs must treat demand response providers, including aggregators, in a non-discriminatory manner and on the basis of their technical capabilities. National regulatory authorities should define arrangements for the participation in these markets on the basis of participants' capabilities and these specifications should include enabling aggregators.[28] The TSOs should define related technical requirements for DSR participation.

3.23 However, WB6 Contracting Parties have not yet adopted an appropriate legal framework to enable active DSR development. There are legal and administrative barriers to DSR participation in electricity and balancing markets.[29] WB6 Contracting Parties do not have secondary legislative framework or contractual templates for demand response participation or aggregators.

3.24 Most of WB6 Contracting Parties do not provide for the participation of demand in response in balancing and ancillary markets, with the exception of Montenegro, and Bosnia and Herzegovina. The Kosovo* transmission system operators makes large use of load shedding for balancing as a last resort measure, but with no commercial incentive for the demand side participants.

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24 See the Energy Community Secretariat's study 'Rocking the boat: What is keeping the Energy Community's coal sector afloat? Analysis of direct and selected hidden subsidies to coal electricity production in the Energy Community's Contracting Parties', September 2019, in particular pages, 9-10 and 19-21, available at the link https://www.energy-community.org/documents/studies.html

25 See dedicated section in Appendix E.

26 Directive 2009/72/EC, as adapted for the Energy Community, Article 3.

27 For a specific overview on each country see Appendix D.

28 See also EU Commission Staff Working Document; SWD (2013) 450 final, Implementing the Energy Efficiency Directive – Commission Guidance, Article 15.

29 For DSR participation in WB6 Contracting Parties in balancing and ancillary markets see dedicated section.

3.25 Most of WB6 Contracting Parties have not so far adopted significant measures or plans for investment in technologies that enable demand response, such as smart meters or smart appliances, with a few exceptions, such as in Montenegro.

3.26 WB6 Contracting Parties do not have any concrete plans to develop frameworks for active demand response. They have insufficient plans for investment in technologies that enable demand response, such as smart meters or smart appliances.

Regional cooperation on electricity market

3.27 In 2014, the WB6 Contracting Parties joined the so-called Berlin Process (Western Balkan 6 Initiative), which aims at strengthening regional cooperation and sustainable growth. At the Vienna summit of 2015, EU Member States participating in the process, Austria, France, Germany, Italy, the United Kingdom and WB6 Contracting Parties decided to take steps to improve energy connectivity in the Western Balkan region.[30] The WB6 Contracting Parties reasserted their commitment to establish a regional electricity market, through implementing a number of soft measures at national and regional level.

3.28 In the Paris Summit 2016, the WB6 Contracting Parties (through their ministries competent for energy, regulatory, TSOs, and future PX operators) committed further on the Connectivity Agenda and the regional dimensions. They signed a Memorandum of Understanding setting a regional operating framework and defining concrete actions to develop the regional electricity market and security of supply (the '**WB6 MoU'**).[31]

3.29 In the WB6 MoU, the WB6 Contracting Parties agreed to provide reasonable resources and take steps towards a set of strategic objectives; namely to analyse, design and implement an organised day-ahead market in each WB6 country and implement market coupling with existing initiatives for coupling with EU neighbouring countries; cross-border balancing; regional capacity allocation; a coordinated capacity calculation for the allocation of day-ahead capacities through the establishment of a regionally coordinated calculator; appropriate regulatory measures to enhance liquidity on the day-ahead market, as well as other cross-cutting horizontal measures. In particular, WB6 Contracting Parties recognised the importance of the CACM Regulation and other upcoming EU Regulations establishing network codes and guidelines and committed to take steps towards implementation.

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30 See Energy Community Secretariat, WB6 Electricity Monitoring Report, 5/2019.

31 See Memorandum of Understanding of Western Balkan 6, 'On Regional electricity market development and establishing a framework for other future collaboration in South East Europe', signed on 27 September 2016, ('WB6 MoU').

3.30 This has further materialised into a WB6 energy connectivity program, supported by the EU, which includes support in implementing such measures, coordination and monitoring at Energy Community level.[32]

3.31 At the Paris Summit of 2016, the WB6 Contracting Parties also endorsed a sustainability charter,[33] which sets a series of measures to support transition towards low-carbon and climate-resilient energy sectors. This includes enhancement of the climate action and transparency of sustainable energy markets.

3.32 A number of neighbouring EU Member States joined the WB6 Contracting Parties and committed to participate in integration projects relating to a regional day-ahead market coupling between WB6 Contracting Parties and neighbouring EU Member States.[34]

3.33 In a declaration following the Trieste Summit of 2017, parties recognised the key role of the cooperation between WB6 Contracting Parties and EU Member States of the WB6 MoU and of Title III measures of the Energy Community Treaty.[35]

Evolution of State aid in the electricity sector in WB6 Contracting Parties

3.34 Article 18 of the Energy Community Treaty read in conjunction with Article 107 of the Treaty on the Functioning of the European Union ('TFEU') lays down the principle that State aid is prohibited, except for certain cases where State aid is allowed in line with the internal market under Articles 107(2) and (3) of the Treaty.

3.35 Article 94 of the Energy Community Treaty, read in conjunction with Article 2 of the Dispute Settlement Rules, obliges both national enforcement authorities and the Energy Community Secretariat to uniformly apply State aid provisions throughout the Energy Community, based on precedents established by EU enforcement institutions.[36] On this basis, the Energy Community Contracting Parties have to comply with Guidelines on State Aid for Environmental

32 See Energy Community Secretariat, WB6 Electricity Monitoring Report, 5/2019.

33 See Energy Community Secretariat's WB6 Sustainability Charter Report 03/2018.

34 See Addendums of WB6 MoU with Bulgaria Regulator, Croatia, Greece TSO IPTO, Greece MO LAGIE, Hungary, Italy PX GME, Italian Ministry, Italian regulator, Romania.

35 See Energy Community Secretariat's WB6 Electricity Monitoring Report, 5/2019.

36 Policy Guidelines by the Energy Community Secretariat on the Applicability of the Guidelines on State Aid for Environmental Protection and Energy 2014-2020, PG 04/2015 / 24 November 2015.

Protection and Energy 2014-2020 (EEAG)[37] and other regulations, notices, guidelines, and case law developed by EU institutions in implementing TFEU provisions on State aid.

3.36 In absence of due transposition into national law, Treaty provisions prevail over conflicting national law and are applied by direct effect.

3.37 While the energy systems in the WB6 Contracting Parties have undergone significant reforms and restructuring, energy subsidies and other forms of state support continue to be an important factor in their energy policies[38] to induce investment in generation capacity to achieve security of supply objectives. In most countries, incumbent generators and most new investors are compensated through channels other than through electricity sale, for instance in the form of subsidies and payments or waiver of debts or other forms of state support that incentivise them to maintain or invest in generation capacity. In many cases, these state support measures are taken for security of supply objectives, without a clear pre-defined justification. In other cases, although security of supply is not the primary goal, it may still be complimentary to other objectives.

3.38 The most typical types of State aid present in WB6, for coal-based and large-hydro generation, are:

- **Fiscal or direct budget support**: tax exemption or tax concessions, direct grants, state loans, write-off of state debt;
- **Public finance support**: state guarantees, shareholder contribution or direct investment in capital and benefits in kind, land lease under more favourable conditions, PPAs that guarantee a certain return on investment, capacity payments;
- **State-owned enterprises (SOE) support**: regular advances, write-off or waiver of debt, loans on preferable terms, non-paid credits; and
- **Hidden subsides or support in other implied forms**: waivers of revenues or foregone revenue by the State in shareholder capacity from operating the state-owned plants at a low or negative level of profitability compared with market levels.[39]

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37 Policy Guidelines by the Energy Community Secretariat on the Applicability of the Guidelines on State Aid for Environmental Protection and Energy 2014-2020, PG 04/2015 / 24 November 2015.

38 See 'Analysis of Direct and Selected Hidden Subsidies to Coal Electricity Production', Energy Community Secretariat's Study, 2019, available at: https://energy-community.org/documents/studies.html - vo9rms-accordion

39 See the Energy Community Secretariat's study 'Rocking the boat: What is keeping the Energy Community's coal sector afloat? Analysis of direct and selected hidden subsidies to coal electricity production in the Energy Community's Contracting Parties', September 2019, at https://www.energy-community.org/documents/studies.html. This Study determines governments in Bosnia and Herzegovina

3.39 A non-exhaustive list of measures is presented in Appendix E.

3.40 We understand that these measures were not properly notified as State aid. Therefore, to comply with the Energy Community Treaty, they may need to be phased out or converted into compatible State aid, such as a Capacity Remuneration Mechanism, as we discuss in Section 5.[40]

3.41 A number of measures existing in WB6 Contracting Parties that appear to have the objective of ensuring that electricity supply matches demand in the medium and long term,[41] could fall under the category of capacity mechanisms as determined in the EU Sector Inquiry.[42] Below we discuss some of these measures, namely state guarantees for investment financing, tenders for new capacity, and some practices to procure ancillary services capacity which could also be considered as State aid.

Kosovo* Montenegro, North Macedonia, and Serbia appear to be waiving profits on this equity contribution on incumbent power companies even compared with the safest state bonds assumed at 3.5% on average (See page 16 and table 6). This Study concludes that most of the power incumbent generators operate at low levels of profitability compared with other market participants and are likely to be incurring operational losses even today without any carbon pricing in place (See page 15).

40 In Appendix E, potential state aid measures to large RES, wind and solar generators are also listed in some instances. In Section 5 we discuss the possibility to convert these measures into compatible State aid in the form of Capacity Remuneration Mechanism. This is without prejudice to other grounds of compatibility under the EEAG, including in particular aid to energy from renewable sources, or aid for going beyond Energy Community standards or increasing the level of environmental protection in the absence of Energy Community standards.

41 In strategy documents and Security of Supply Statements, including without limitation, Albania Council of Ministers Decision No. 742, dated 12.12.2018 'On approval of the strategic plan for the reform of the energy sector'; Framework Energy Strategy of Bosnia and Herzegovina until 2035; Kosovo* Security of Supply Statement, 2017; Kosovo* Energy Strategy 2017-2026; Kosovo* Energy Strategy Implementation Program 2018-2020; North Macedonia, Security of Supply Statement, 2019; North Macedonia, Strategy for the energy development until 2030; Montenegro, Energy Development Strategy by 2030, including action plan 2016-2020; Republic of Serbia, Security of Supply Statement, 2018; Republic of Serbia Energy Sector Development Strategy for the period by 2025, with projections up to 2030; Republic of Serbia Decree on the Implementation program for of the energy sector development strategy for the period to 2025, with projections up to 2030.

42 Findings of the EU Sector Inquiry apply to the Energy Community Contracting Parties to the extent that they show how the Energy Community state aid acquis and the EEAG ought to be interpreted and implemented in connection to aid for generation adequacy. See Section 5 for more details on this classification.

State guarantees for investment financing

3.42 Certain forms of public support such as state guarantees are present in some countries, not only for coal or large hydro but also for large wind or solar.[43] For example, States typically provide support to incumbent operators when they need to raise financing to implement capacity construction or refurbishment works. In such cases, tenders are typically launched by the incumbent (dominant) generators for the construction of a new unit or refurbishment of existing units, for the selection of the construction company. The incumbent generators will own such newly constructed or refurbished capacity and operate it on the electricity market as normal.[44]

3.43 Financing of such works is however often secured through state support, primarily in the form of guarantees provided by the State. A typical example would be the TPP Tuzla Block 7 project[45] where the EPBiH is raising financing relying on a state guarantee granted by the Federation of Bosnia and Herzegovina.[46] In other cases, the State itself raises all or part of the financing through direct loans with an international financial institution (as for example in the case of the Loan Agreement of Republic of Serbia with China Bank for the Kostolac 3)[47] and transfer the funds to the incumbent (e.g. Republic of Serbia to the EPS' subsidiary).[48]

Tenders for new capacity

3.44 WB6 Contracting Parties implement tenders for the selection of contractors for the construction and operation of new plants or capacity units or refurbishing of existing capacity.

3.45 In these tenders the selected contractor will own the newly constructed plant and operate it on the electricity market for a given period of time. The project is typically supported through power purchase agreements (PPA) with mandatory offtake obligation by an entity designated

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43 See Appendix E, specific sector on Serbia.

44 These tenders for construction works are technology specific; they specify many characteristics of the capacity to be constructed or refurbished, including the size, technology type, location and technical specifications.

45 See Tuzla 7 project details made publicly available by EPBiH at: https://www.epbih.ba/eng/page/capital-investments and https://www.epbih.ba/novost/20190/guarantee.

46 Federation of Bosnia and Herzegovina approved state guarantee in relation to the Tuzla 7 project besides ongoing dispute settlement procedure opened by the Energy Community Secretariat and alleged incompliance with state aid rules. See also Review Tuzla 7 project under EU state aid rules of the state guarantee granted by Bosnia and Herzegovina, March 2019.

47 See Loan Agreement between the Government of the Republic of Serbia and the Export-Import Bank of China, dated 17.12.2014, publicly available.

48 We have not found publicly available information on the nature of the agreement entered between the Republic of Serbia and the EPS subsidiary (100% owned by the Republic of Serbia) for such transfer of funds. We may assume it is performed in the form of a shareholder loan or shareholder contribution.

by the State as well as through other support measures. The PPA and the other project documents would define the revenue streams of the investor. On this basis the investor would be able to raise financing for the construction of the new capacity and secure return on investment during the operation.

3.46 We have found one project in the WB6 Contracting Parties that clearly falls under this category, namely the Kosova e Re. It also seems that the bidders in the tender for the refurbishment and gas-conversion of the Vlora TPP in Albania or the planned Cebren pumped-storage hydropower project in North Macedonia, have required a PPA, but there is no further information publicly available.

3.47 In the Kosova e Re competitive process, the winner of the tender has concluded the Kosova e Re project contracts, which consist of several agreements[49] including:

- **A PPA** between Government of Kosovo* (whose rights are assigned to its 100% subsidiary) and Contour Global, which guarantees over 20 years mandatory purchase of generated electricity at a pre-set electricity price that covers variable costs (e.g. fuel costs, etc.) and operation and maintenance costs, payment for capacity availability that covers investment costs and a nominal equity rate of return; exemption from a number of costs such as balancing costs, etc, and reimbursement of a number of environmental costs incurred due to compliance with acquis on the environment.

- **State guarantee** of payment of any amounts due from all publicly owned enterprises under Kosova e Re project agreements; and

- **Additional advantages.** Reimbursement of take-or-pay payments to KEK mining for lignite supply; exemption from VAT and tax reliefs for the construction and development activities; transfer of properties at symbolic prices.

3.48 These tenders had the following eligibility and allocation rules:

- **Eligibility**. These tenders for new capacity are technology specific; they define many characteristics of the capacity to be constructed, including the size, technology type, location, technical specifications and environmental requirements. From information publicly available, it appears that the Kosova e Re tender required a lignite-fired electric power generation facility at a pre-determined location;

- **Allocation process and award criteria**. The private investor in Kosova e Re was selected after an open international competitive process for the selection of the contractor to develop, construct, finance, own, operate and maintain the new power plant. It seems that the selection was based on the most advantageous economic offer assessed through a

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49 Kosova e Re's project agreements are publicly available at: https://mzhe-ks.net/en/commercial-contracts-of-tc--kosova-e-re--project#.XkHew2hKg2w.

points system. The Project was to be awarded solely to one successful bidder or a Consortium.

- **Security of supply criteria.** In the Kosova e Re PPA, the contractor is required to maintain existing capacity to guarantee the security of electricity supply in return for remuneration of pre-defined availability payments. PPA payments for availability and for generated electricity together cover the total fixed and variable costs of construction and operation of the Kosova a Re, plus a pre-determined profit margin for the investor. Most of the commercial and environmental risks are passed on to public authorities. This creates the conditions for project bankability.

3.49 This mechanism would fall under the CM category of 'tender for new capacity' as defined in the EC Sector Inquiry, as this tender is meant to secure the financing for the construction of new capacity covering all investment and operational costs for bringing forward the new capacity. The new capacity would not run on the electricity market as 'normal', but for a 20-years period would be operated under the above-mentioned PPA and other project documents.

Ancillary Services Capacity

3.50 In the Sector Inquiry, the EC noted that ancillary services can have the same effect as capacity mechanisms and could represent State aid. The EC considers that ancillary services do not represent State aid if:

- ancillary services are procured independently by TSOs, and determination of volume requirements and types of services to be procured is left to the TSOs without Government involvement;

- procurement of such services is performed in a transparent, competitive and non-discriminatory way, thereby excluding undue advantages; and

- ancillary services are used in small volumes relative to the overall level of capacity in the market and only to provide short term corrections to enable system security.

3.51 However, the framework that applies to ancillary services reserves in certain WB6 Contracting Parties, such as Serbia, Albania, and Montenegro could have certain characteristics of capacity mechanisms reserves:

- In Serbia, there is 'government involvement'[50] in setting the volumes for capacity availability for balancing services and in designating capacity providers. The regulator AERS sets prices for secondary and tertiary reserves based on an estimation of revenues

[50] Here by Government involvement we mean any setting of conditions for availability of capacity reserves for ancillary services by public authorities or other authorities (including by the regulator), which is not defined independently by the TSO.

the capacity provider (i.e. EPS) would have earned if capacity was not held in reserve, but had sold electricity on the power exchange at average annual futures market prices for base-load production.

- In Albania, there is also government involvement[51] for designating the capacity provider (KESH) and setting prices for capacity availability for balancing services (including both secondary and tertiary reserves).

- In Montenegro and North Macedonia, the regulator sets prices for capacity availability.

3.52 In all WB6 Contracting Parties it seems ancillary services reserves are used only in small volumes for short-term corrections.

State of implementation of European environmental legislation

3.53 As Contracting Parties of the Energy Community, the Western Balkan countries (WB6) – Albania, Bosnia and Herzegovina, Kosovo,* Montenegro, North Macedonia and Serbia are legally bound to implement the core EU energy legislation, the so-called "acquis communautaire”. Below we summarise the aquis in particular with respect to the environment and climate change, carbon pricing and carbon tax, and electricity regulation.

Acquis on environment and climate change

3.54 The WB6 Contracting Parties shall comply with setting specific Large Combustion Plants Directive (LCPD) and Industrial Emissions Directive (IED) rules, as adapted to the specific situation of the Energy Community Contracting Parties:[52]

- **Large Combustion Plants Directive (LCPD).** WB6 Contracting Parties were required to transpose into national legislation and implement LCPD requirements by 31 December

51 Here by Government involvement we mean any setting of conditions for availability of capacity reserves for ancillary services by public authorities or other authorities (including by the regulator), which is not defined independently by the TSO.

52 For LCPD purposes, ‘existing plant’ means any combustion plant for which the original construction licence or, in the absence of such a procedure, the original operating licence was granted before 1 July 1992. ’New plant’ means any combustion plant for which the original construction licence or, in the absence of such a procedure, the original operation licence was granted on or after 1 July 1992. For IED purposes, ‘existing plant’ means combustion plants that have been granted a permit before 1 January 2018, or the operators of which have submitted a complete application for a permit before that date (provided that such plants are put into operation no later than 1 January 2019); ‘new plant’ means all other plants that do not fall under the definition of existing plants. For an interpretation of the notion of new and existing plant under the IED in the Energy Community, see Energy Community Secretariat Policy Guidelines PG 02/2014, 17 November 2014.

2017.[53] The LCPD offered the WB6 Contracting Parties three options for existing large combustion plants to achieve compliance.[54] Under the first option, existing plants should meet the Emission Limit Values (ELVs) by the indicated date. Under the second option, WB6 Contracting Parties could opt for an alternative method of compliance for existing plants other than through the compliance with ELVs; namely they could opt for the implementation of a national emission reduction plan (NERP), which provides for a gradual reduction of the emissions of the plants covered by the NERP towards an emission ceiling based on the emission limit values in the IED. A NERP may be applied between 1 January 2018 and 31 December 2027 only.[55] Under the third option, WB6 Contracting Parties could opt for an exemption from compliance with ELVs for existing plants[56] and from their inclusion in the NERP ('so-called limited lifetime derogation' or referred to below as 'Opt-Out') on the following conditions:

- the operator of an existing plant undertakes, in a written declaration submitted by 31 December 2015 at the latest to the competent authority, not to operate the plant for more than 20,000 operational hours starting from 1 January 2018 and ending no later than 31 December 2023**;**

- the Ministerial Council, in the form of a decision and following a verification by the Secretariat that the above conditions are met, authorizes this exemption in the form of a decision approved by the majority of its members including a vote in favour by the European Union.

- From the point in time when the plant has been operating for 20,000 hours since 1 January 2018 and in any case from 1 January 2024 onwards, the plant shall not be operated further unless it meets the emission limit values set out in Part 2 of Annex V to Directive 2010/75/EU (IED). [57]

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53 Decisions 2013/05/MC-EnC on the implementation of Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants.

54 Decisions 2013/05/MC-EnC on the implementation of Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants.

55 See Policy Guidelines by the Energy Community Secretariat, PG 03/2014.

56 ELVs set under Article 4(3) of the LCPD.

57 Decisions 2013/05/MC-EnC on the implementation of Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants.

- **Industrial Emissions Directive[58] rules**. WB6 Contracting Parties shall implement[59] Chapter III, Annex V, and Article 72(3)-(4) of the IED (Directive 2010/75/EU) for new plants starting from 1 January 2018, and for existing plants by 1 January 2028 at the latest.[60] WB6 Contracting Parties should however endeavour to implement the provisions of Chapter III and Annex V for existing plants within the shortest possible timeframe before the stated deadline, in particular in the case of retrofitting existing Energy Community plants.

- **Recommendation on BAT.** To meet IED emission values, WB6 Contracting Parties are invited to implement Chapter II of the IED on the use of best available techniques including those established by the European Commission, including for large combustion plants. WB6 Contracting Parties are in the process of preparing the legal and institutional preconditions for the implementation of the core elements of Chapter ll, Chapter lV and Annex Vl of the IED in their jurisdictions.

3.55 Based on the exemption decision of the Energy Community Ministerial Council[61] and respective submissions by WB6 Contracting Parties' competent authorities, the following existing plants exercised the Opt-Out.

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58 Directive 2010/75/EU.

59 D/2013/06/MC-EnC: On the implementation of Chapter III, Annex V, and Article 72(3)-(4) of Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) and amending Article 16 and Annex II of the Energy Community Treaty.

60 D/2015/06/MC-EnC: on the implementation of Chapter III, Annex V, and Article 72(3)-(4) of Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) for existing combustion plants and amending Annex II of the Energy Community Treaty.

61 D/2016/19/MC-EnC: on authorising exemption of plants from compliance with the emission limit values set by Directive 2001/80/EC of the European Parliament and of the Council.

Table 2: Existing plants having exercised the Opt-Out

Country	Plant	Fuel	Operator	RTI	Year
BiH	TPP Tuzla-3	Lignite/brown coal	EPBiH	330	1966
BiH	TPP Tuzla-4	Lignite/brown coal	EPBiH	600	1971
BiH	TPP Kakanj-5	Lignite/brown coal	EPBiH	330	1970
Montenegro	TPP Pljevlja-I	lignite	EPCG	516	1982
Serbia	Termoelektrana Morava	lignite	EPS	420	1969
Serbia	Kolubara A, A3. Boiler 1	lignite	EPS	147	1956
Serbia	Termoelektrana Kolubara A A3 (boilers 3,4,5)	lignite	EPS	441	1961
Serbia	TE Kolubara A5	lignite	EPS	382	1972

Notes: *Final Opt-out List.*
Source: *Energy Community Secretariat Report.*

Carbon pricing or carbon tax system

3.56 CO2 emissions are not currently priced in the WB6 Contracting Parties. Firms do not face the cost of CO2 emission, in particular, with regards to coal/lignite electricity generation. The production costs that are borne by the concerned generator(s) are lower than the costs borne by society, i.e. they do not include externalities. In the absence of the carbon tax or emission trade scheme, the coal-based generators do not pay for the CO2 emissions. Only Montenegro has introduced an excise tax on coal used for electricity generation.[62] Already in 2014, the High-Level Reflection Group on the Energy Community advised on the introduction of an ETS system for the Energy Community, similar to that at EU level.[63] This was not followed by any concrete action as to the ETS system, but progress is being made in terms of GHG reporting and monitoring.

3.57 In parallel, the Paris Agreement leads to increased pressure on WB6 Contracting Parties to reduce emissions and as such may require phasing out of unlawful subsidies and implementing carbon pricing or a carbon tax system. WB6 Contracting Parties, save Kosovo* have ratified the Paris Agreement and submitted their Nationally Determined Contributions

62 Energy Community Secretariat, Analysis of Direct and Selected Hidden Subsidies to Coal Electricity Production in the Energy Community Contracting Parties, June 2019, p. 17.

63 Energy Community, High Level Reflection Group, 2014, “An Energy Community for the Future”.

(NDCs). Kosovo* too is developing an energy strategy in which it addresses emission reductions.

3.58 Pursuant to EU accession agreements, WB6 Contracting Parties should prepare frameworks and link to the EU ETS at the latest by their EU accession date. WB6 Contracting Parties have started preparatory works in this respect, such as drafting climate laws laying down the basis for implementing carbon pricing, identification of ETS installations and formulation of monitoring, reporting and verifying (MRV) systems for ETS.

3.59 All WB6 Contracting Parties, save Kosovo* identify in their strategy documents actions for implementing ETS without, however, providing a concrete timeline.

3.60 Various studies have suggested that WB6 Contracting Parties should take a phased approach prior to linking to the EU ETS system, so preparing for the transition and revealing the true societal costs of GHG emissions. Proposals include considering a regional ETS market in the Western Balkans (e.g. within the framework of the Energy Community as suggested by the HLRG Report[64]) or introducing carbon pricing for WB6 Contracting Parties which would be harmonised nationally and/or regionally.

CO2 Emission Performance Standard

3.61 In June 2019, the Commission adopted an updated Electricity Regulation 2019/943 (‘Electricity Regulation’), as part of its Clean Energy Package. The Electricity Regulation is not part of the Energy Community acquis yet but is expected to be incorporated in 2020.

3.62 One of the provisions of the new Electricity Regulation is a new eligibility condition for participation in a capacity remuneration mechanism based on CO2 emission limits. In EU Member States, this condition excludes new installations emitting more than 550g of CO2 per kWh of electricity immediately at the entry into force (i.e. 4 July 2019) of the EU Regulation. From July 2025, this condition excludes the existing installations emitting more than 550g of CO2 per kWh and 350 kg of CO2 on average per year per KW of installed capacity.

3.63 In the Energy Community we may expect the 550g CO2/kWh Emission Performance Standard to apply to new plants starting from the date of the entry into force of the Electricity Regulation for the Contracting Parties (i.e. presumably by 2020-2021).

3.64 For existing plants, we assume there will be a transitory period until implementation of the Emission Performance Standard. The implementation deadline for the 550g CO2/kWh and 350kg CO2/kW-year Emission Performance Standard to existing plants could possibly be the same as the deadline for the general application of the IED and BAT, i.e. by 2028.

64 Energy Community, High Level Reflection Group, 2014, “An Energy Community for the Future”.

Conclusion

3.65 Despite significant progress in the past years, the current electricity sector organization in the WB6 Contracting Parties represents an incomplete stage of liberalization of the wholesale market. To align with European regulation on electricity, WB6 Contracting Parties have made and will need to make further progress in three areas:

- **Evolution of the WB6 electricity markets towards the EU target model.** On the one hand, the electricity sector of WB6 Contracting Parties is evolving and timelines for introduction of organised power exchanges and market coupling have been already set. However, a number of elements of the market design will still remain to be addressed, such as balancing and ancillary services markets, the presence of certain regulated prices in the wholesale and in the retail markets, and integration of DSR. On the other hand, the regulated share of the market remains substantial and 50% to 90% of volumes generated by incumbents in the WB6 are reserved for the suppliers of regulated customers. The volumes traded by market participants on the free wholesale market represent mainly the cross-border trade to sell the incumbents' surplus or procure volumes to cover shortages for incumbents or network losses.

- **Evolution of the State aid interventions in the WB6 electricity sector.** The WB6 electricity sector is still characterised by a significant involvement of the state in form of subsidies and State aid. Current investment in generation capacity in electricity markets in the WB6 Contracting Parties is significantly affected by direct or indirect state support that determine incentives to invest in capacity and which support investors through channels other than market prices. Investors in capacity receive state support that can translate into certain lower costs of operation and costs of investment in capacity, directly or indirectly.[65] Coal for instance remains largely more supported than renewables in WB6 Contracting Parties.[66] Compliance with Energy Community State aid regulation may require either phasing out these measures or converting them into measures compliant with State aid regulation.

- **Implementation of European environmental legislation.** Pursuant to the Energy Community law and EU accession context, the WB6 Contracting Parties need to apply the EU environmental regulation in the electricity sector, and in the future emission norms for power plants and carbon pricing. The WB6 Contracting Parties must comply with the specific rules of the Large Combustion Plants Directive (LCPD) and the Industrial Emissions Directive (IED) adapted to the specific situation of the Energy Community Contracting Parties. The WB6 Contracting Parties are also likely to be required to introduce an ETS system for the Energy Community, similar to the one existing at the EU level or another form of carbon pricing. Although the Electricity Regulation 2019/943 ('Electricity Regulation') adopted by the EC on June 2019 is not yet part of the Energy Community acquis, it is expected to be incorporated in 2020. One of the provisions of the new

65 See Appendix E.

66 For a quantification, see the Energy Community Study on subsidies to coal, page 4, and Appendix E.

Electricity Regulation is a new emission limit of 550g of CO_2 of fossil-fuel origin per kWh of electricity as an eligibility condition for participation in capacity mechanisms.

Section 4

Adequacy outlook in WB6 Contracting Parties with implementation of EU target model and environmental legislation

Introduction

4.1 This section written by Compass Lexecon presents the analysis of forward adequacy outlook for WB6 Contracting Parties. As discussed in the previous section, further implementation of EU electricity market target model and environmental regulations in the WB6 Contracting Parties would require alignment with:

- **The EU Target Model.** Alignment of markets regulations with the European target model requires a number of reforms, including wholesale power market reforms[67] and market coupling implementation within and with neighbouring EU countries;[68]
- **European environmental regulation.** This includes increased RES penetration targets, implementation of the Large Combustion Plan Directive (LCPD) and of the BAT[69] standards defined within the Industrial Emissions Directive (IED),[70] and pricing power production externalities through the participation in the European CO2 Emission Trading Scheme ETS, or another equivalent form of carbon pricing; and
- **Phasing out of existing State aid.** Various existing forms of State aid may be incompatible with the European State aid rules and may need to be phased out.

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67 Planned wholesale market reforms are outlined in more detail in Section 2.

68 Planned reforms in WB6 Contracting Parties on market coupling to meet the EU target model are outlined in more detail in Section 2.

69 BAT stands for Best Available Technics defined in the BREFs documents (http://eippcb.jrc.ec.europa.eu/reference/lcp.html) published in July 2017 for Large Combustion Plants.

70 Applicability of the LCPD and IED adapted to the institutional framework and circumstances of the Energy Community WB6 Contracting Parties is explained in Section 2.

4.2 Implementation of these reforms could negatively impact the profitability of existing thermal plants in the WB6 region, and the incentives for new capacity investment. As a result, the reforms may lead to resource adequacy issues.

4.3 In this section, we focus on the likely impact of EU environmental legislation (i.e. carbon pricing and implementation of LCPD and IED) on WB6 power plants. In particular, in all assessed scenarios, we assume that (i) the EU target model is implemented in the WB6 region (i.e. fully competitive power markets, perfect market-coupling) and (ii) current State aids are phased out (e.g. no complementary source of revenue beyond electricity market revenue, unsubsidised fuel prices). The only differences between the assessed future scenarios are (i) the implementation of carbon pricing and (ii) future environmental norms (LCPD and IED).

4.4 The section below provides an overview of the methodology and key results. The full detail of the methodology, underlying assumptions and country by country results is included in Appendices A, B and C.

Adequacy assessment framework

4.5 This section presents the adequacy assessment background and the approach we will follow to assess the future adequacy of WB6 power markets. To justify the need for state intervention via a CM, we need to:

- First, define a security of supply target and then assess whether the target could be reached without state intervention; if not, then we justify that state support is needed to assure security of supply. In this way we demonstrate that there is a clear need for state intervention with a clearly defined objective;

- Second, ensure that our assessment process is in line with the objective of phasing out environmentally harmful subsidies, i.e. by removing from our modelling the subsidies currently paid to lignite plants.

Security of supply target

4.6 To be able to identify potential adequacy issues as well as their severity, a security of supply target needs to be determined. This target is often defined as an expected number of hours of loss of load (LOLE), which quantifies the expected number of hours in a year during which power interruptions may be needed for some customers.

4.7 Defining the security of supply target requires a trade-off between cost and reliability: a 100% reliable power system would entail costs that consumers are not willing to pay. It implies finding the point at which the incremental cost of insuring customers against power cuts through additional capacity investment is equal to the incremental cost to customers of power cuts.

4.8 The economically optimal security of supply target could be determined based on the comparison of the Cost of investment in best New Entry technology (CONE) and the expected cost of loss of load, given by the Value of Lost Load (VOLL). The ratio between the values would result in an optimal number of hours of loss of load (LOLE), which can be used as the security of supply target.

$$LOLE = \frac{CONE}{VOLL}$$

4.9 Grounding the security of supply target on the VOLL, as required by the revised Electricity Regulation ("*The reliability standard shall be calculated using at least the value of lost load* […]"[71]), ensures that an economically efficient level of adequacy is reached and that expensive overprotection against shortages is avoided. ENTSO-E is currently in the process of defining the methodologies to establish the Reliability Standard based on the LOLE target derived from VOLL and CONE.

4.10 The scope of this study does not include the calculation of the VOLL for WB6 Contracting Parties. However, we need to determine the security of supply target against which we will analyse the future adequacy of W6 power markets.

4.11 While existing European capacity mechanisms generally apply a 3-hour LOLE target (e.g. France, UK, Italy…), based on a VOLL of 20,000€/MWh, such a high VOLL seems unlikely for WB6 Contracting Parties, given lower incomes.[72] For instance, values computed for neighbouring countries of the WB6 region (Bulgaria, Romania, Croatia…) are much lower than the VOLL used to define a 3-hour target and are in the lower range of European values.[73] As a result, the WB6 region should have less stringent security of supply targets, reflecting the lower cost to customers of power cuts. In this study, we assume a security of supply target equal to 6 to 8 hours to assess the future adequacy of WB6 power markets. Assuming a cost of investment in best new entry technology of 60k€/MW/year, this implies a VOLL between 7,500 and 10,000€/MWh.[74]

Forward adequacy modelling

4.12 Once the security of supply target is defined, the second step of the adequacy assessment is a forward-looking adequacy outlook, which assesses whether the security of supply target can be reached without state intervention, while considering the anticipated revenues and costs of power plants.

4.13 The forward adequacy assessment is done using the combined modelling of the Market Model and Adequacy assessment model, both based on a common set of background assumptions.

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71 Article 25, REGULATION (EU) 2019/943 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on the internal market for electricity.

72 Value of lost load is traditionally computed considering (among other factors) (i) hourly wages for the domestic sector, and (ii) gross value added for the non-domestic sector.

73 See for instance the VOLL computed for all EU Members States by ACER in its Study on the estimation of the value of lost load of electricity supply in Europe (https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf).

74 Security of supply target should be defined by each WB6 Contracting Party.

These common assumptions relate to demand and forecasts, (renewable, hydro, thermal capacity…), cross-border capacity evolution, commodities and costs as well as the modelling framework used for the analysis. They are introduced in Appendix B.

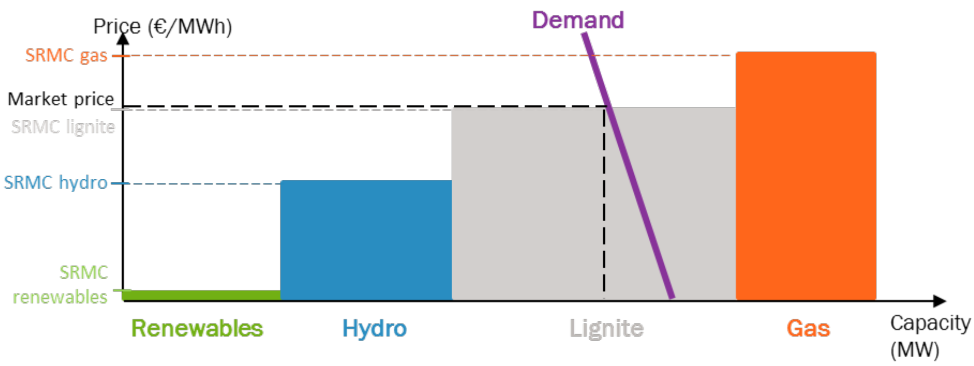
Power market model

4.14 The power market model assesses the short-term and long-term economic dispatch of power plants.

Short-term economic dispatch

4.15 The power market model assesses the wholesale electricity price based on the marginal value of energy. Generation decisions are based on a Short Run Marginal Cost (SRMC) merit-order dispatch: plants with lower short-run marginal costs are dispatched first. Power prices are then computed based on the costs of the marginal producing unit.

Figure 1: Illustration of the SRMC merit-order principle



Source: FTI-CL.

Long-term economic dispatch

4.16 The simulated power price and generation volumes are then used to determine the net present value (NPV) of future revenues and costs and thus to derive investment and shutdown decisions. The NPV addresses the well-known “missing money problem” stemming from current energy-only market design, by comparing on the one hand expected revenues, both from the energy market and the ancillary services market, and on the other hand expected costs (variable costs, fixed operation and maintenance costs and (i) refurbishment costs to comply with LCPD or IED for existing plants or (ii) investment costs for new plants).

4.17 Based on the NPV calculation, investment and shutdown decisions are derived (e.g. new plants are not built if their NPV is negative) and installed capacity evolves dynamically and endogenously within the power market model framework. This enables the capacity outlook based on an economic equilibrium to be derived.

Adequacy assessment model

4.18 The adequacy assessment model studies whether the future expected installed capacity would be enough to meet the security of supply target. It accounts for expected market developments and the likelihood of power plants staying online / being retired / being added to the system based on pre-defined capacity outlooks (for instance based on TSO's forecasts), or capacity outlooks derived from the market model.

4.19 To account for key risks and uncertainties, including peak demand sensitivity to temperature, the availability of thermal plants or the availability of renewable production (wind, solar, hydro), the adequacy assessment uses probabilistic simulations (e.g. Monte-Carlo simulations) to model a representative range of potential outcomes.

4.20 As its main output, the adequacy assessment model provides security of supply indicators, such as margin or LOLE, which are then compared with the defined security of supply targets to in turn assess the need for CM implementation.

Combined modelling of the Adequacy assessment model and Market model

4.21 Using future investment and shutdown decisions determined by the market model as inputs of the adequacy assessment model enables us to conclude whether the economic equilibrium of the capacity mix ensures adequacy and whether a CM is needed to meet the security of supply target.

4.22 This combined adequacy analysis framework thus brings additional insights compared with existing adequacy studies, such as the MAF performed by ENTSO-E or national adequacy assessments performed by national TSOs.[75] Indeed, these studies rely on the adequacy assessment model only to study future adequacy and do not consider the power market model economic equilibrium. As a result, the economic profitability of power plants is not tested, so these studies cannot conclude whether plants necessary to meet the security of supply target will be indeed available or whether they will be decommissioned or not built because their expected revenues are insufficient to cover their future variable, fixed and investment costs. Moreover, existing adequacy studies do not assess the impact on adequacy of future emission-related norms (LCPD and IED) and the potential implementation of the EU ETS market in the WB6 region. We address these limits in the combined adequacy analysis framework.

Common assumptions and scenario definition

General framework of the adequacy modelling

4.23 Our modelling is based on our FTI-CL Energy proprietary power market model. The model accounts for a detailed representation of power market fundamentals at an hourly granularity: each unit connected to the transmission grid, decentralised generation, renewable output and its variability, specificities of hydro power and interconnectors, as well as demand fluctuations, are considered. Our model is implemented in the state-of-the-art commercial modelling

75 For instance, Kosovo* (cf. KOSTT, 2018, Plani i adekuacisë së gjenerimit 2019-2028. Available in Albanian at: http://www.kostt.com/website/images/stories/dokumente/tjera/Plani_i_Adekuacise_se_Gjenerimit_2019-2028.pdf)

platform Plexos®, most commonly used in the European electricity industry by utilities, regulators and transmission system operators. Further explanations on our power market model are presented in Appendix A.

4.24 The system adequacy in WB6 Contracting Parties is assessed from 2020 to 2030, on an extended regional geographic scope including WB6 Contracting Parties and their first-tier neighbouring (from a power market point of view) countries (Greece, Bulgaria, Romania, Hungary, Croatia, Slovenia and Italy)[76].

4.25 We assume that power markets operate under current market rules, are fully competitive and coupled (within WB6 Contracting Parties and with neighbouring countries) within the bounds of the future Net Transfer Capacities (NTC).

4.26 Assuming fully competitive power markets under current market rules implies that (i) generation decisions are based on hourly merit-order dispatch based on marginal cost of production of the different power plants, (ii) power plant operators bid their short run marginal cost (SRMC) based on unsubsidised fuel prices and unsubsidised variable operation and maintenance costs, and (iii) wholesale power prices would be subject to the current wholesale power price cap of 3000€/MWh.

4.27 Subsidies on coal generation are frequent in the WB6 region:[77] they can translate into lignite prices or fixed maintenance and operation costs for coal-based electricity producers which are significantly lower than in unsubsidised countries. In this study, we remove subsidies by considering, for all lignite plants in WB6 Contracting Parties: (i) market-based lignite prices, and (ii) typical fixed operation and maintenance costs.

4.28 Forward looking probabilistic Monte-Carlo power market simulations are designed considering a 30 samples approach, based on three representative weather samples, as defined by ENTSO-E,[78] and ten randomly drawn outage patterns for thermal plants based on forced outage rates provided by each TSO.

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76 A new transmission line is expected between Montenegro and Italia in 2020. Although Slovenia is not directly adjacent to the WB6 region, it is included in the modelling to link the Italian and Croatian power systems.

77 See Energy Community Secretariat, 2019, Rocking the Boat: What is Keeping the Energy Community's Coal Sector Afloat? Analysis of Direct and Selected Hidden Subsidies to Coal Electricity Production in the Energy Community Contracting Parties. Available at: https://www.energy-community.org/dam/jcr:23503de3-fccd-48f8-a469-c633e9ac5232/EnC%20Coal%20Study%20Report%20WEB.pdf

78 Cf. ENTSOE, 2018, TYNDP 2018 Data and expertise as key ingredients. Available at: https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/Technical/DataExpertise.pdf

WB6 power market assumptions

4.29 Future WB6 power markets are mainly defined by the five fundamental drivers being (i) power supply (e.g. generation capacity and demand side response), (ii) power demand (including reserves), (iii) cross-border interconnection capacity, (iv) commodities including gas, coal, oil, CO_2 and (v) operating cost.

4.30 While (i) assumptions for commodities are based on the World Energy Outlook (WEO) 2018 published by the International Energy Agency (IEA) and on values provided by the Directorate-General for Energy (DG Ener) of the European Commission and (ii) assumptions for costs are based on a literature review, scenarios for the evolution of the first three market fundamentals (supply, demand and interconnection) are grounded on latest TSO's publications (mainly national network development plans, and generation adequacy studies when existing). Assumptions on the five drivers are introduced in Appendix B.

Scenario and sensitivity definitions

4.31 We assess the impact of reforms on resource adequacy by considering and comparing several scenarios. In all assessed scenarios, we assume that (i) the EU target model is implemented in the WB6 region (i.e. fully competitive power markets, perfect market-coupling) and (ii) current State aids are phased-out (e.g. no complementary source of revenue beyond electricity market revenue and unsubsidised fuel prices). Further, to assess the impact of possible future environmental reforms (i.e. carbon pricing and implementation of LCPD and IED environmental norms) on adequacy assessment, we model and compare the outcomes of the following scenarios:

TSOs Base Case scenario

4.32 The Base Case scenario is based on TSOs' base case scenarios for capacity forecast with the corrected RES capacity assumed for 2030. Contrary to scenarios presented below, long-term decisions regarding investments and closures are inputs to the model and are not estimated based on the Market model. In particular, the base case scenario assumes that all new plants mentioned by TSOs will become operational.[79] Similarly, the base case scenario relies on the closure decisions considered by TSOs in their studies.[80] Contrary to both the other scenarios presented below, long-term decisions regarding investments and closures are considered as exogenous and are therefore fixed - these are inputs of the model and are not economically optimised. As a result, the long-term capacity mix of the base case scenario may not represent a long-term economic equilibrium since profitability of new and existing power plants is not assessed (for instance, the model does not assess whether new plants will earn enough money to cover their investment costs). However, the base case scenario still relies on a short-term economic equilibrium to dispatch power plants. Generation decisions are based on a merit-order dispatch: plants with lower short-run marginal costs are dispatched first. Power prices are then computed based on the costs of the marginal producing unit.

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79 Cf. Table 21 in Appendix B.

80 Cf. Table 22 in Appendix B.

4.33 Moreover, the base case scenario assumes that WB6 Contracting Parties do not apply a carbon price or enter the EU ETS market. Short-run marginal costs are based on fuel prices and variable operation and maintenance costs only.

4.34 Finally, it should be noted that the base case scenario does not fully consider the impact of future environmental norms (LCPD and IED). Apart from power plants which decided to opt out from the LCPD and which are considered to close by 2023, forecasts made by TSOs do not seem to consider the possibility of not investing in refurbishment to comply with LCPD and more importantly with IED limits. However, it is likely that for some plants, the operator will decide that it is not economical to keep them operational and to comply with environmental norms, which will lead to closures. This possibility is not considered in the base case scenario. In other words, apart from plants in the opt-out list for LCPD, the base case scenario assumes that all plants will refurbish and will be compliant with the new environmental norms, regardless of the economic conditions.

Energy Only market scenarios

4.35 As the aim of the adequacy study is to assess the impact on adequacy of the economic signal sent by the current energy-only market to invest in power plants (refurbishment or new), future refurbishment or new investments considered by the TSOs in their national development plans are not taken as a given in the Energy-only market scenario framework. Contrary to the base case scenario, in addition to the short-term equilibrium based on SRMC, a long-term capacity equilibrium needs to be determined based on energy revenues.

4.36 As a result, the Energy-only market scenarios differ from the base case scenario for capacity investments whose main revenues would come from the wholesale energy market (e.g. thermal units, large hydro). We refer to such investments as “merchant-based”. Such investments are highly dependent on power prices and should be made only if their expected net present value is positive.[81] Investment decisions in these technologies, as well as refurbishment and closure decisions, are then endogenous within the model, based on their profitability assessment of the Energy Only market. Investment decisions are made only if there are economically justified (net present value positive) and closure decisions are made whenever profits do not enable covering fixed avoidable costs (i.e. fixed operation and maintenance costs).

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81 On the contrary, capacity where main revenues are not related to wholesale market revenues (e.g. wind, PV and small hydro units, whose revenues are based on subsidies or PPA contracts), referred to as “*non-merchant-based”*, are considered as always built into the Energy-only market scenarios since investments are less dependent on energy revenues and would be mainly driven by energy policies.

4.37 Also, contrary to the base case scenario, we assume that power plants are subject to a full CO2 price in the Energy Only market scenarios. We distinguish two scenarios depending on when the CO2 price starts to be implemented:[82]

- the EU ETS 2030 Energy Only scenario, in which WB6 Contracting Parties enter the EU ETS market from 2030 onwards.
- the EU ETS 2025 Energy Only scenario, in which WB6 Contracting Parties enter the EU ETS market from 2025 onwards.

4.38 Finally, environmental norms (LCPD and IED) are considered in the energy-only market scenarios: to comply with them and continue producing, existing power plants need to refurbish by 2023 for the LCPD and by 2028 for the IED. These additional fixed costs will decrease competitiveness and may force operators to close their plants in anticipation.

4.39 Differences between the three studied scenarios are summarised in Table 3. EU ETS Energy Only scenarios would represent the most challenging situation for WB6 Contracting Parties, as existing carbon intensive lignite plants would be heavily impacted by the carbon price implementation and, to a lesser extent, by refurbishment costs to comply with environmental norms.

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82 For transparency of the modelling results, we consider that in these scenarios the CO2 price is fully phased in one year. In Section 5 we discuss possible transitional schemes for the gradual introduction of CO2 pricing.

Table 3: Summary of differences between studied scenarios

	Base Case	**EU ETS 2030 Energy Only**	**EU ETS 2025 Energy Only**
Investment, refurbishment and shutdown decisions for **merchant-based** capacity	Endogenous, based on TSO's studies	Exogenous, based on profitability assessment	Exogenous, based on profitability assessment
Investment, refurbishment and shutdown decisions for **non-merchant-based** capacity	Endogenous, based on TSO's studies	Endogenous, based on TSO's studies	Endogenous, based on TSO's studies
Implementation of the EU ETS CO2 pricing	No	From 2030 onwards	From 2025 onwards
Refurbishment costs to comply with environmental norms (LCPD and IED)	Not considered	Considered	Considered

Source: FTI-CL.

4.40 In addition to the Base Case and the Energy Only market scenarios, we consider several sensitivities to assess the incremental impact of several elements of the reforms on adequacy, in particular, transitional introduction of the CO2 price and the efficiency of market coupling:

Sensitivity of transitional CO2 price between 2025 and 2029

4.41 Implementation of EU ETS in the WB6 Contracting Parties is expected to have a significant impact on the profitability of existing lignite plants. To assess the extent to which lignite plant economics would be impacted by a different carbon price, we perform a sensitivity analysis by considering that (i) WB6 Contracting Parties apply a transitional CO2 price between 2025 and 2029, different from the EU ETS CO2 price, and (ii) WB6 Contracting Parties ultimately enter the EU ETS market in 2030. Mechanisms of such gradual phase-in of the CO2 prices are discussed in Section 5.

4.42 More precisely, we compute the maximum CO2 price that lignite plants in WB6 Contracting Parties can face between 2025 and 2029 without endangering their future economics, i.e. the optimal CO2 price in the WB6 region that would prevent lignite plant closures as far as possible (considering that the WB6 Contracting Parties enter the EU ETS market in 2030 in all cases).

Market coupling efficiency sensitivity

4.43 Given the importance of cross-border exchanges for the WB6 Contracting Parties, we perform a sensitivity analysis of the EU ETS 2025 and 2030 Energy Only scenarios by limiting the import volume from neighbouring countries, which mimics a potential inefficient use of cross-border capacity within WB6 Contracting Parties and with neighbouring countries. We reduce cross-border imports of WB6 Contracting Parties by 1.4GW, i.e. 20% of expected 2030 import capacity.[83]

Results of the plant profitability and adequacy outlook

4.44 This section presents the results of the power market model for each of the three scenarios – Base Case, EU ETS 2030 Energy Only, and EU ETS 2025 Energy Only – including the profitability of the different power plants, and power price and generation outlooks. The resulting capacity outlook is then studied, based on the associated investment or shutdown decisions.

TSOs Base Case scenario

Profitability assessment for lignite plants

4.45 First, Figure 2 presents profitability for lignite plants in the Base Case scenario. It should be recalled that this scenario does not correspond to a long-term economic equilibrium since capacity is based on TSO's forecast only and is not updated endogenously within the market model based on profitability assessment. However, the base case relies on a short-term economic equilibrium in the sense that capacity is dispatched according to the merit-order principle. Power prices are then determined by the marginal costs of the most expensive producing unit and the profitability of plants can be computed.

4.46 For the purpose of the economic analysis we define the Net profit as:

Net profit = Energy revenues + Ancillary services revenues - Variable Generation costs - Fixed O&M costs[84]

4.47 Net profit is compared with two reference values:

- The Annualised investment CAPEX for new lignite plants (115€/kW).
- The Annualised LCPD and IED CAPEX for existing lignite plants requiring refurbishment: LCPD CAPEX are relevant for years 2020 and 2025 whereas IED CAPEX mainly relate to year 2030 (since IED limits apply from 2028 onwards for existing plants).

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83 More precisely, (i) sum of Serbian cross-border imports from Croatia, Hungary, Romania and Bulgaria are capped at 2GW, or 700MW lower than the maximum import capacity; (ii) Bosnian cross-border imports from Croatia are capped at 1GW, or 300MW lower than 2030 import capacity, and (iii) Montenegrin cross-border imports from Italy are capped at 600MW, or 400MW lower than 2030 import capacity.

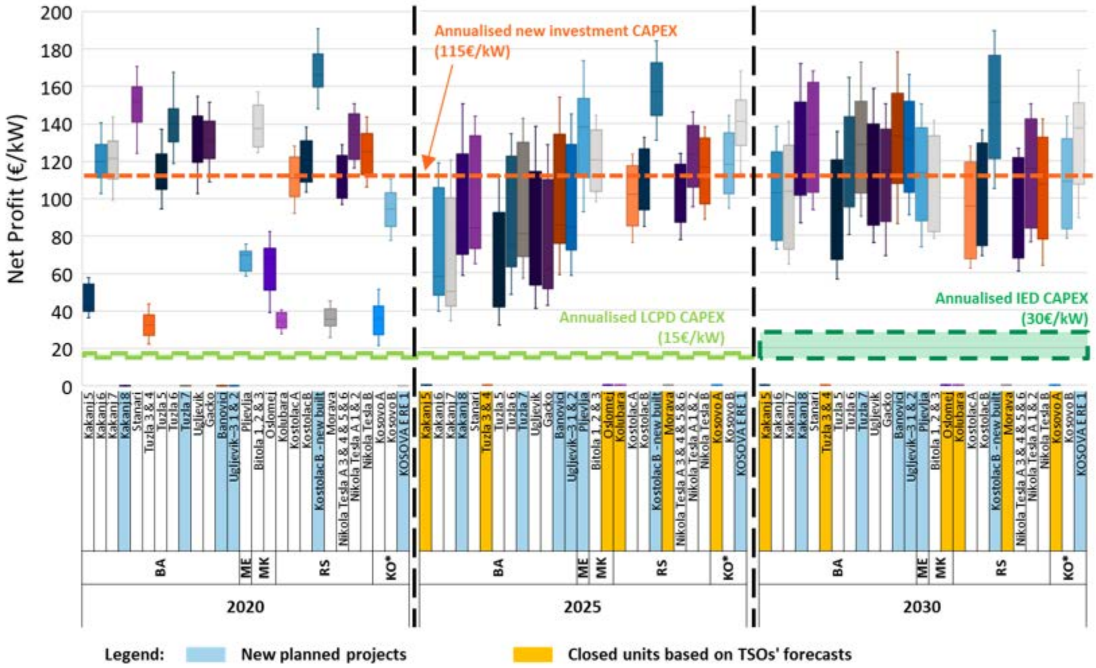
84 This definition slightly differs from usual energy profits definitions which do not include Fixed O&M (FOM) costs (which are considered in a later stage).

4.48 The range of the net annual profit (in €/kW) is graphically depicted with a box plot diagram.[85] This range reflects the results obtained from 30 samples corresponding to the climate condition variations and outages patterns.

4.49 To simplify the figures, profitability is depicted for 2020, 2025 and 2030 only. Moreover, to reduce the size of the graph, we focus only on lignite plants that we gather by country and by similar technical characteristics. The graph shows the ranges of the annualised net profit of lignite plants estimated by the model across the climate and outage scenarios. Comparison of these net profits with benchmarks allows assessing the decision for an existing plant to stay or for a new plant to be constructed:

- For a new plant, the relevant benchmark is the annualised new investment CAPEX;
- For an existing plant, the reference is the annualised capex of the LCPD or IED investments.

Figure 2: Net profit of lignite plants in the Base Case scenario



Notes: *Profitability of new projects (in blue) should be compared with the Annualised CAPEX level whereas profitability of existing plants should be compared with the LCPD CAPEX level for 2020 and 2025 and with the IED CAPEX level for 2030 (IED limits apply from 2028 onwards for existing plants).*

Source: *FTI-CL.*

4.50 Apart from new capacity in Bosnia and Herzegovina in 2025, net profits of new thermal power plants are positive over the 2020-2030 period and remain larger than annualised CAPEX of a

85 A boxplot is a standardised way of displaying the distribution of data based on a five-number summary: minimum, first quartile (Q1), median, third quartile (Q3), and maximum.

new coal power plant (115€/kW/year). New investments considered by the TSOs are then justified from an economic point of view in the Base Case Scenario.

4.51 For new plants in Bosnia and Herzegovina, the conclusion is less evident: in 2025, net profits are not high enough to cover annualised investment CAPEX while the opposite occurs in 2030, implying that new investments in commissioning assumed in the TSO base case could be phased in more progressively.[86]

4.52 Existing plants always experience profitability levels above required annualised refurbishment CAPEX: their refurbishment to comply with LCPD (in 2020/2025) and IED norms (in 2030) appears to be relevant from an economic point of view. However, their profitability is slightly lower than the profitability of new plants: this is explained by the higher efficiency of the latter (e.g. Kostolac-B No 3, Kosova e RE).

4.53 High profitability of both existing and new plants is explained by the low generation costs of lignite plants in the WB6 region, thanks to the absence of CO2 pricing, whereas they sell their generation at high power prices, aligned with generation costs in foreign countries, which are subject to a CO2 price. Given the importance of power prices to explain the profitability level, a more detailed analysis of the power prices outlook in the WB6 Contracting Parties is provided below for the base case scenario.

4.54 A more detailed analysis of the net profit results of Figure 2 highlights several interesting points. First, the specific economic situation of plants in the LCPD opt-out list can be noticed in 2020 (Kakanj 5, Kolubara A, Morava 1, Tuzla 3 and 4, Pljevlja 1). Since these plants have to run on a limited number of hours between 2018 and 2023, their profitability is reduced compared with other lignite plants.[87]

4.55 Oslomej and Kosovo-A units also experience low (but still positive) profitability. For Kosovo-A, this is explained by its low efficiency and the resulting high generation costs. The Oslomej unit is assumed to be decommissioned in June 2020 so it earns revenues on the energy market for only half of the year. On the contrary, several recent and more efficient plants have higher profitability (e.g. Kostolac-B No 3, Kosova e RE, Stanari 1).

4.56 Finally, the variability of profitability among the 30 samples can be noticed. This can be explained by the importance of hydro generation in WB6 Contracting Parties. In wet years,

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86 This conclusion is aligned with the latest 2020-2029 Bosnian network development plan (https://www.nosbih.ba/files/dokumenti/Indikativan%20plan%20razvoja/2019/IPRP%202020-2029%20FINAL.pdf). In this study, several new lignite plants are delayed by one year (e.g. Tuzla 7 or Kakanj 8) or not considered (Ugljevik 3 and Banovici).

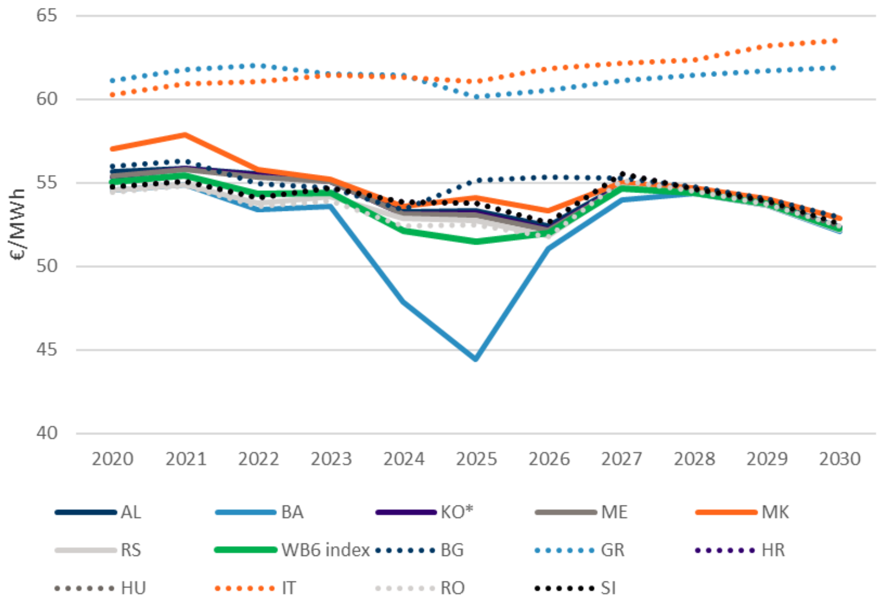
87 We assumed that the 20,000 operating hours are evenly distributed between 2018 and 2023. In reality, from the reporting of 2018, we already can see preliminary indications that this is not the case and that plants are run at or close to full load. It is thus very likely that they will reach the 20,000 hours limit as soon as 2020 or 2021.

high hydro generation tends to decrease power prices and thus profitability of lignite plants compared with dry years. The increasing share of intermittent renewables (wind and PV) also impacts the volatility of net profits: this is particularly true in 2030 (compared with 2020 and 2025 results).

Power prices outlook

4.57 Annual average power prices are shown on Figure 3 for the base case scenario and for all WB6 Contracting Parties, as well as neighbouring countries. We also add a WB6 price index, computed as the load-weighted price average of WB6 Contracting Parties.

Figure 3: Power price outlook in the Base Case scenario



Source: FTI-CL.

4.58 Except for North Macedonia in 2020-2021 and Bosnia and Herzegovina in 2024-2025 (whose specific case is studied below), annual average prices in WB6 Contracting Parties are almost all equal up to 2030 and, more importantly, aligned with prices experienced in neighbouring countries (Bulgaria, Croatia, Romania…). This is explained by the high level of available cross-border capacity compared with national peak demands and our assumptions of a fully efficient use of interconnections. In particular, we can notice that the price convergence increases over the time horizon thanks to the commissions of new cross-border lines (e.g. AL-MK in 2022, BA-HR in 2028, BA-ME in 2025/2026, BA-RS in 2026, ME-RS in 2024).

4.59 The Italian and Greek power prices are significantly higher due to higher generation costs, combined with limited import capacity compared with their peak demands (Italy is mainly dominated by gas power plants while Greece is dominated by gas plants and lignite plants, whose generation costs are higher than those in other countries).

4.60 Since prices in neighbouring countries are often set by coal or lignite units whose generation costs already include a CO2 price (e.g. in Bulgaria, Hungary or Romania), lignite plants in

WB6 Contracting Parties sell the electricity at a relative high price, around 55 €/MWh, while their generation costs are around 20-30 €/MWh.

4.61 The specific situation in Bosnia and Herzegovina in 2024-2025 is explained by the commission of 1 GW of new (and affordable)[88] lignite plants during these years (Banovici 1, Kakanj 8 and Ugljevik 3): as a result, exports to neighbouring countries (including WB6 Contracting Parties) increase up to the maximum cross-border capacity.[89] Bosnia and Herzegovina tends to be decoupled from other markets and experience lower power prices on average. Following the addition of new cross-border capacity in 2026 (500 MW with Serbia and 150 MW with Montenegro), the price convergence between Bosnia and Herzegovina and other countries increases. The lower power prices in 2025 explain the temporary lower profitability of Bosnian plants in Figure 2.

4.62 North Macedonia also experiences slightly different average prices in 2020-2021 due to higher generation costs and limited import capacity (compared with its peak load). This price divergence is solved from 2022 onwards following the commission of a new cross-border line with Albania.

4.63 Moreover, except for Bosnia and Herzegovina in 2024-2025 and North Macedonia in 2020-2021, annual average prices in WB6 Contracting Parties are quite stable over the studied time horizon since factors which tend to increase prices (such as higher demand, closures of some thermal plants, increase of CO2 prices in foreign countries) are somewhat offset by factors with downward impact (investment in new efficient plants, RES development…). A slight decrease can be noticed from 2028 onwards, explained by the more pronounced development of renewable capacity (wind and PV). This decrease partly explains the lower profitability in 2030 for plants in all countries except Bosnia and Herzegovina compared with 2025 levels (cf. Figure 2).

EU ETS 2025 Energy Only scenario

4.64 Compared with the base case scenario, the EU ETS 2025 Energy Only scenario mainly differs by (i) the introduction of a C02 price from 2025, and (ii) the endogenous capacity mix evolution, based on profitability assessment. As described below, the introduction of a CO2 price will strain lignite plants' profitability, which will consequently result in cancelled new investments or shutdown decisions.

Profitability assessment for lignite plants

4.65 To better explain the producers' reaction once the WB6 region enters the EU ETS market and how a new long-term economic equilibrium is reached, Figure 4 illustrates the evolution of profitability in 2025 in five consecutive steps.

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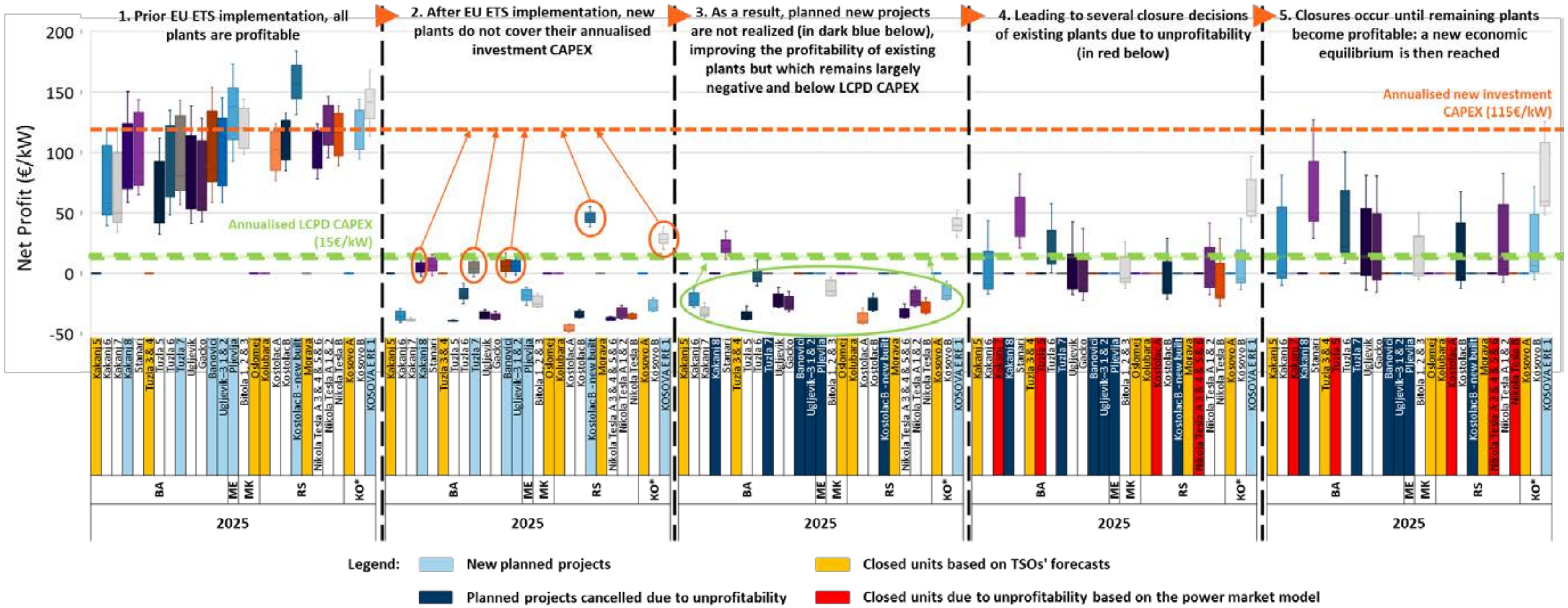
88 Since the base case scenario does not include CO2 EU ETS.

89 Assuming neighbouring countries do not take action to limit imports from Bosnia and Herzegovina.

Figure 4: Illustration of the market reaction following the EU ETS implementation



Note: *Profitability of new projects (in blue) should be compared with the Annualised CAPEX level whereas profitability of existing plants should be compared with the LCPD CAPEX level.*

Source: *FTI-CL.*

- First, net profits of lignite plants are presented before the introduction of CO2 pricing (first section of Figure 4). All new plants except for those in Bosnia and Herzegovina are profitable at the annualised CAPEX investment of new builds. All existing plants have net profits above their annualised CAPEX refurbishment level: they can comply with LCPD and continue producing.

- Second, as soon as the EU ETS is introduced, new and existing lignite plants would become unprofitable due to higher generation costs (second section of Figure 4). Even if net profit of new plants is still positive (thanks to their higher efficiency), it is well below the annualised CAPEX threshold (new projects are circled in orange): as a result, a rational economic actor would not invest in the first place in such power plants.[90]

- Third, removing new investments leads to power price increases as power systems become tighter. These price increases improve the profitability of existing plants, but this remains largely below the annualised LCPD refurbishment CAPEX (third section of the Figure 4), apart from Stanari and Kosovo e RE units, thanks to their higher efficiency.

- Fourth, as a result, operators of the least profitable plants decide not to invest in refurbishment: their plants close once the LCPD becomes binding (December 2023). The first closures concern the Kakanj 5, Tuzla 5, Kostolac A et Nikola Tesla A units since they have the highest losses (depicted in red in the fourth part of the Figure 4).

- Finally, these consecutive closures lead to further power prices increase[91] and thus higher profitability for remaining plants (which can be noticed by comparing the third, fourth and fifth sections of the Figure 4, for instance for Kakanj 6), until remaining existing plants would expect net profit in the range of LCPD refurbishment annuity (cf. fifth section of the Figure 4). This final step corresponds to the economic equilibrium in 2025 following the EU ETS introduction.

4.66 Overall, 3.1 GW of lignite plants would be expected to close in the WB6 region in late 2023 since their refurbishment to comply with LCPD is not economic (in addition to the 2.5 GW of cancelled new investments).

4.67 Similarly, at least 1.3 GW of additional lignite capacity are expected to be decommissioned in late 2027 since they would not be profitable enough to cover their IED refurbishment CAPEX (in particular due to the assumed increasing CO2 price and due to the downward impact of RES development on power prices).

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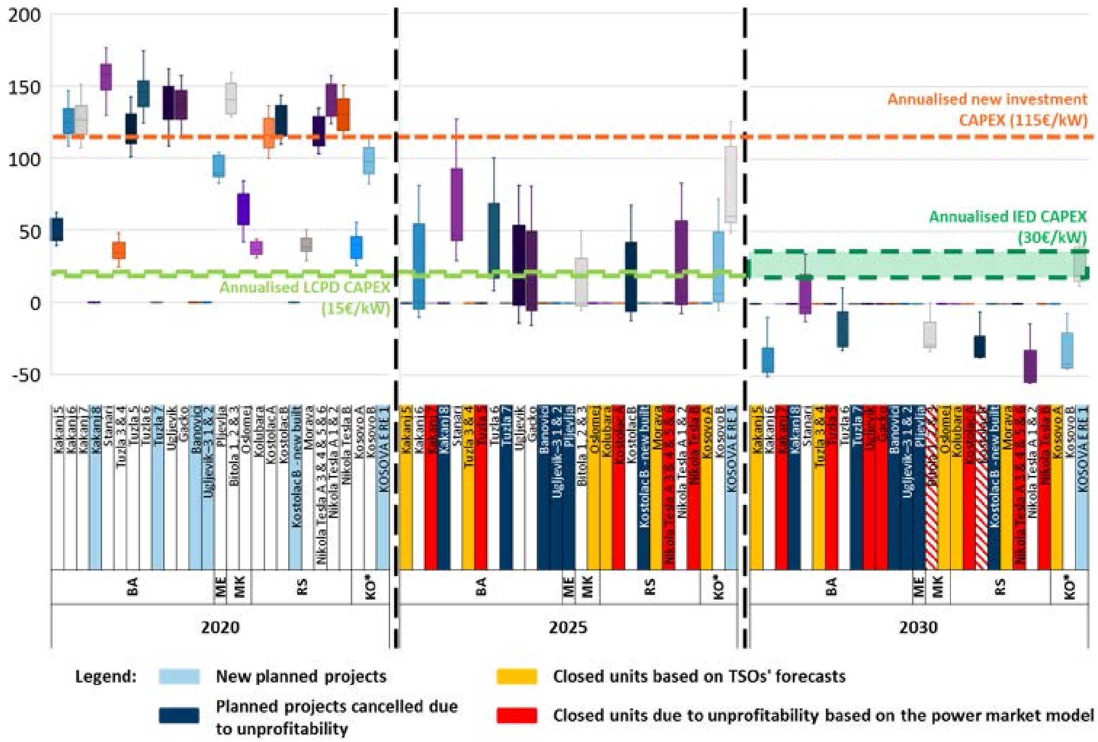
[90] The new plant Kosova e RE is assumed to be built anyway since it is considered as a non-merchant-based unit.

[91] Note: The economic equilibrium reached in the EU ETS scenarios depends on the price cap assumption. The analysis considers the current price cap of 3000€/MWh – the higher the price cap would be, the higher would be the profitability of power plants in the Energy Only market and the fewer closure decisions would be made.

4.68 Figure 5 illustrates the final net profits of lignite plants in the EU ETS 2025 Energy Only scenario for years 2020, 2025 and 2030. New projects that are cancelled as well as units closed for economic reasons are also highlighted on this figure. As explained previously, installed lignite capacity in the WB6 region dramatically decreases due to adverse economic conditions Tighter supply and demand conditions result in price increase, which improves the economic situation of remaining plants.

Figure 5: Net profit of lignite plants in the EU ETS 2025 Energy Only scenario



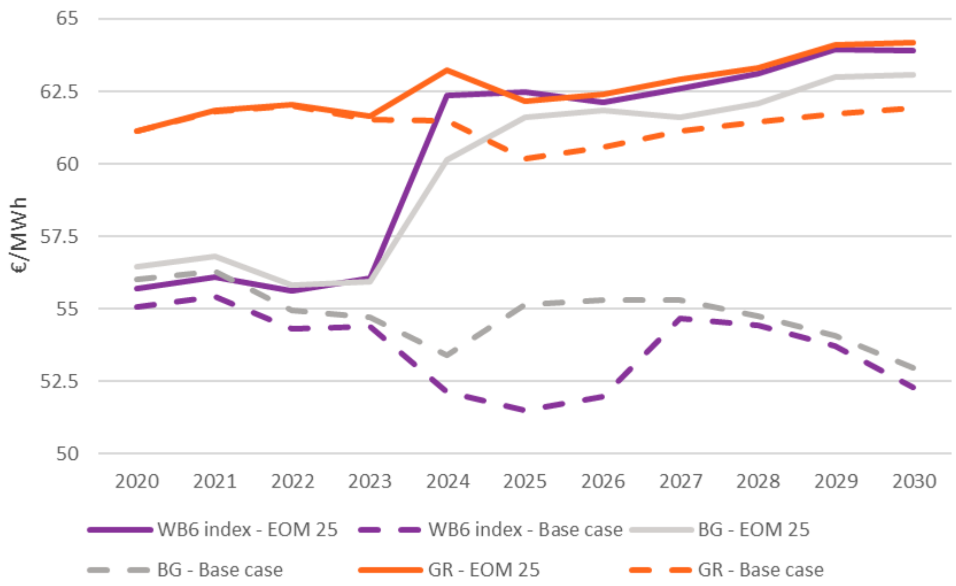
Notes: *In 2030, for Bitola units, only units 1 and 2 are closed. For Kostolac-B units, only unit 1 is closed. Profitability of new projects (in blue) should be compared with the Annualised CAPEX level whereas profitability of existing plants should be compared with the LCPD CAPEX level for 2020 and 2025 and with the IED CAPEX level for 2030 (IED limits apply from 2028 onwards for existing plants)*

Source: *FTI-CL*

Power price outlook

4.69 The impact of power plants closures and cancelled projects on power prices is illustrated on Figure 6 and compared with the base case scenario. To reduce the number of depicted lines, scenarios are compared for a WB6 index price, computed as the load-weighted price observed in WB6 Contracting Parties. Given the high price convergence between WB6 Contracting Parties, this index is assumed representative of results for all WB6 Contracting Parties. The index is compared with prices in Greece and Bulgaria.

Figure 6: Power price outlook in the EU ETS 2025 Energy Only scenario



Source: FTI-CL

4.70 Firstly, when comparing both scenarios, prices are higher in the energy only scenario as soon as 2020. Indeed, Kostolac-B-3 unit, which is expected to become operational in 2020 in the base case scenario, would not be built in the EU ETS scenario due to its forecast negative profitability from 2025 onwards once carbon pricing is implementing[92]. Removing this more efficient plant (compared to older units) would result in price increase since more expensive generation capacity is needed to meet demand.

4.71 Second, power prices in WB6 markets significantly increase in 2024. This is explained by (i) cancelled projects of new plants (e.g. Banovici 1 and Kakanj 8) and (ii) closure of several unprofitable lignite plants which cannot comply with LCPD, both resulting in higher generation from more expensive plants, either in WB6 Contracting Parties or abroad.

4.72 As a result, following the implementation of EU ETS, power prices in WB6 Contracting Parties converge to neighbouring countries' level, such as Greece, already subject to CO2 prices, bringing the other regional power prices (incl. Bulgaria) to this new level.

EU ETS 2030 Energy Only scenario

4.73 Compared to the previous scenario, the EU ETS 2030 Energy Only scenario only differs by the implementation year of the carbon pricing. As a result, consequences on profitability and investment and closures decisions will be similar but with some delay.

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92 Even if the plant can make positive profits until 2025, it will be not enough to cover the total investment CAPEX.

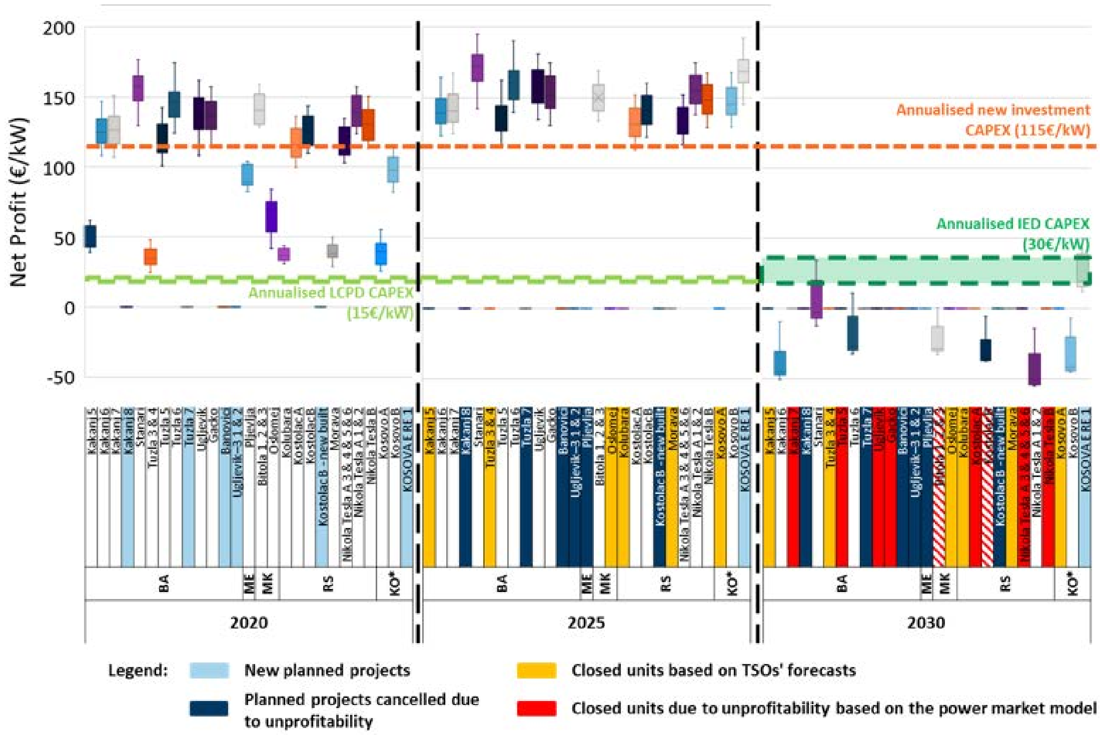
Profitability assessment of lignite plants

4.74 Net profits of lignite plants in the EU ETS 2030 Energy Only scenario are illustrated on Figure 7 for years 2020, 2025 and 2030.

4.75 Compared to the EU ETS 2025 Energy Only scenario, the higher profitability of power plants in 2025 can be noticed: this is explained by the absence of carbon pricing during this year. As a result, existing plants earn enough money to make refurbishment investments to comply with LCPD and stay online after 2023. However, the economic situation is different for new projects. Indeed, the future EU ETS implementation makes carbon intensive project uneconomic from 2030 onwards, thus leading to a negative NPV of future profits (even if positive profits can be earned up to 2030, there are not sufficient to cover all CAPEX investments). That is why new projects are also cancelled in the EU ETS 2030 scenario like in the EU ETS 2025 scenario (cf. second part of Figure 7).

4.76 Furthermore, once WB6 Contracting Parties enter the EU ETS market in 2030, profitability of existing lignite plants significantly decreases. In particular, net profits are below annualised IED refurbishment CAPEX: least profitable plants will not invest in refurbishment and will close by late 2027, once the IED limits are applied. Market players will react as in the EU ETS 2025 Energy Only scenario, by closing power plants (4.4GW in total), leaving remaining plants barely economic in 2030 (cf. third part of Figure 7).

Figure 7: Net profit of lignite plants in the EU ETS 2030 Energy Only scenario



Notes: *In 2030, for Bitola units, only units 1 and 2 are closed. For Kostolac-B units, only unit 1 is closed. Profitability of new projects (in blue) should be compared with the Annualised CAPEX level whereas profitability of existing plants should be compared with the LCPD CAPEX level for 2020 and 2025 and with the IED CAPEX level for 2030 (IED limits apply from 2028 onwards for existing plants).*

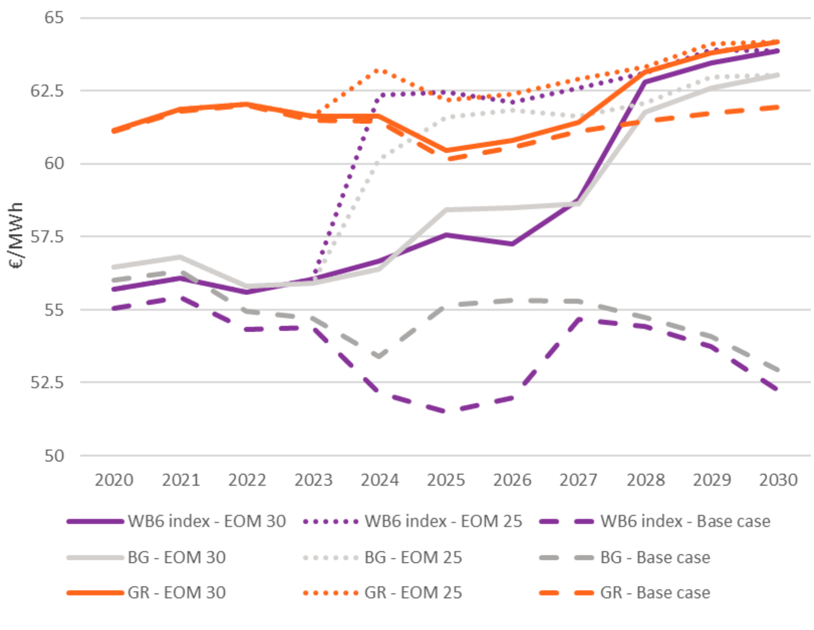
Source: *FTI-CL*

Power prices outlook

4.77 Figure 8 illustrates the resulting power prices and compares them with the base case scenario and the EU ETS 2025 Energy Only scenario. Up to 2023, prices are the same as in the EU ETS 2025 Energy Only scenario and higher than in the Base Case scenario. Indeed, the implementation of a CO2 pricing, either from 2025 or 2030, has the same result on investment decisions made between 2020 and 2023: NPVs of planned new projects are negative and these plants are never built, resulting in the same price increase. From 2024 to 2029, some new projects are cancelled in the EU ETS 2030 scenario (e.g. Ugljevick 3), explaining the higher price spread with the base case scenario.

4.78 However, contrary to the EU ETS 2025 scenario, existing plants make net profits above the annualised LCPD refurbishment CAPEX and do not close in late 2023 (like in the EU ETS 2025 Energy Only scenario): as a result, the price increase remains modest compared to the EU ETS 2025 scenario between 2024 and 2027. However, the expected introduction of a CO2 pricing in 2030 worsens the economic situation of existing plants, which cannot cover the IED refurbishment costs. As a result, several plants close by late 2027 as they cannot comply with IED. This translates into significant price increase up from 2028. In 2030, prices are the same as in the EU ETS 2025 scenario since economic conditions are exactly the same (same investment and closure decisions and same CO2 price).

Figure 8: Power price outlook in the EU ETS 2030 Energy Only scenario



Source: FTI-CL

Capacity outlook in the EU ETS 2025 and 2030 Energy Only scenarios

4.79 We analyse the resulting capacity outlook in lignite plants in the EU ETS 2025 and 2030 scenarios, following investment and shutdowns decisions.

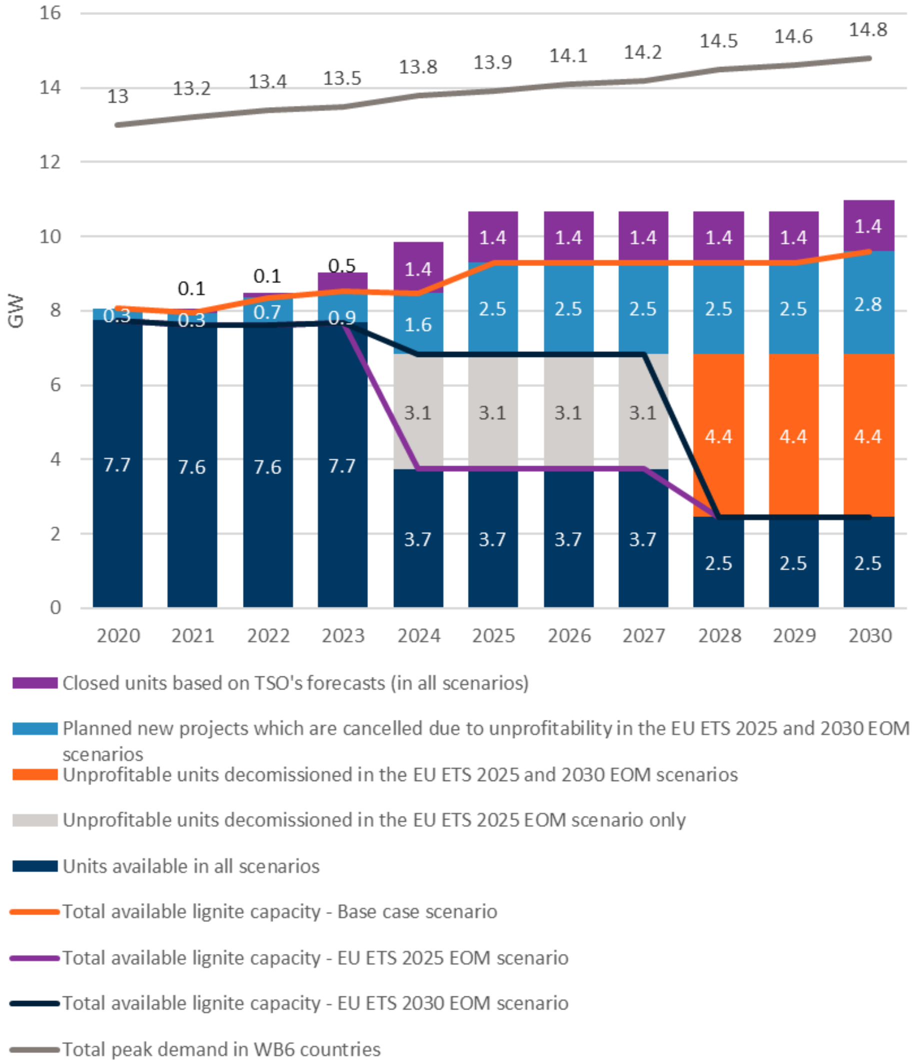
4.80 Figure 9 illustrates the resulting net capacity of lignite plants in WB6 Contracting Parties in the EU ETS 2025 and 2030 Energy Only scenarios (compared to the Base Case scenario). Moreover, it explains for which reason lignite plants are not available in each scenario, namely:

- Plants expected to close based on TSO's forecast (mainly because they are on the LCPD opt-out list) – they are the same in all scenarios (in purple on Figure 9);
- Planned new projects which are not realised due to unprofitability – it occurs in the Energy Only scenarios only (in light blue on Figure 9);
- Existing plants which cannot make refurbishment investments to comply with environmental norms and which are decommissioned – it occurs in the Energy Only scenarios only. We distinguish plants which are closed in the EU ETS 2025 Energy Only scenario only (in grey) and plants which are closed in both Energy Only scenarios (in orange).

4.81 Compared to the Base Case scenario, lignite capacity in the EU ETS Energy Only scenarios is reduced due to both cancelled projects and economic decommissions. Overall, 4.4 GW of lignite plants are closed due to unprofitability to comply with environmental norms and 2.8 GW of new lignite plants are cancelled. Among closures, 3.1 GW are closed in late 2023 in the EU ETS 2025 Energy Only scenario since they do not make any profits to invest in refurbishment to comply with LCPD. However, these plants continue producing in the EU ETS 2030 Energy Only scenario. An additional 1.3 GW close in late 2027 in the EU ETS 2025 Energy Only scenario due to the IED limits whereas closures amount to 4.4 GW in the EU ETS 2030 Energy Only scenario.

4.82 It should be noticed that both EU ETS Energy Only scenarios lead to the same capacity mix from 2028 onwards and they differ only by the transition period between 2023 and 2027. Indeed, as long as the CO2 price is the same in 2030, it would result in the same impact on profitability and then on investment and refurbishment decisions. In particular, in both scenarios, all new projects are cancelled given that the introduction of CO2 prices, either in 2025 or 2030, makes their NPV negative.

Figure 9: Net capacity (in GW) of lignite plants in WB6 Contracting Parties in the three scenarios



Source: FTI-CL

Sensitivities

Sensitivity of transitional CO2 price between 2025 and 2029

4.83 Given the importance of the CO2 price on the profitability of lignite plants, we perform a sensitivity on the level of CO2 price in the WB6 region which would enable existing plants to remain operational, i.e. to cover their refurbishment CAPEX.

4.84 In this sensitivity analysis, we assume (i) that the WB6 region will implement a CO2 price as soon as 2025, but different from the EU ETS price and (ii) that the WB6 region will enter the EU ETS market in 2030 at the latest. The sensitivity then focuses on the transitional period between 2025 and 2029 and on the level of the transitional CO2 price that will mitigate lignite plants closures in the WB6 region. In this sensitivity analysis, we only modify the CO2 price in

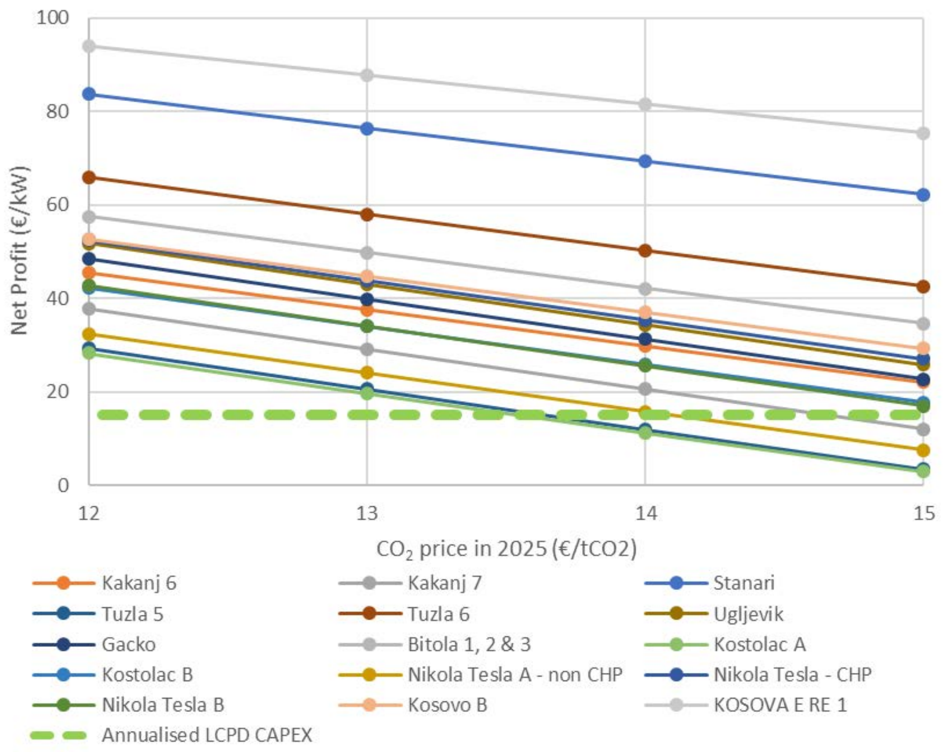
WB6 Contracting Parties: we assume that neighbouring countries are still subject to the EU ETS scheme and to the same CO2 price as in the EU ETS 2025 and 2030 scenarios.

4.85 Given that a transition to full carbon EU ETS pricing is assumed for WB6 Contracting Parties by 2030 (at the latest), market players will not invest in new lignite plants between 2020 and 2030 since they would expect their profitability to be below annualised CAPEX from 2030 onwards, resulting ultimately in a negative NPV. As a result, as long as the EU ETS market is implemented in 2030, planned new projects will be cancelled, regardless of the transitional CO2 price between 2025 and 2029. The sensitivity on transitional CO2 price then focuses on the profitability level of existing lignite plants only.

4.86 We first study the year 2025 and the CO2 price level that should be implemented in WB6 Contracting Parties to prevent decommissioning of lignite plants. To avoid being closed, net profit of existing plants should at least cover their refurbishment CAPEX to comply with LCPD (15€/kW/year). We compute the maximum CO2 price by iterations, based on our power market model and based on the 30 distinct sample.

4.87 Results on the sensitivity analysis are illustrated on Figure 10. It depicts for different future CO2 prices in WB6 Contracting Parties and in 2025 the resulting net profits of existing lignite power plants over the 30 samples.

Figure 10: Net profit of existing lignite plants in 2025 for different CO2 prices in the WB6 region in 2025



Note: Net profit should be compared with annualised LCPD CAPEX (the green dotted line).
Source: FTI-CL

4.88 To prevent decommissioning (i.e. to avoid net profits below annualised LCPD CAPEX), the transitional CO2 price in WB6 Contracting Parties should not be higher than 13-14€/tCO2 in 2025. Higher prices would make LCPD refurbishment investments unprofitable for the least efficient plants like Tuzla 5 or Kostolac A, which would then close by late 2023.

4.89 By contrast, the CO2 price assumed in 2025 in the WB6 region in the EU ETS 2025 Energy Only scenario is equal to 22.5€/tCO2. This high carbon price results in several lignite closures which are avoided with a price equal to 13-14€/tCO2.

4.90 The computed CO2 price in WB6 Contracting Parties should be kept at the same level until at least 2028 to incentivize existing plants to invest to comply with LCPD. However, given that the WB6 region is assumed to ultimately enter the EU ETS scheme in 2030, having a relatively low transitional price in 2028 and 2029 would not encourage investment in refurbishment to comply with IED since these costs must be recovered over 10 years. Consequently, the CO2 price in the WB6 region can increase from 2028 onwards to reach the EU ETS level in 2030 (assumed equal to 30€/tCO2). Having a transitional CO2 price in 2028 and 2029 would not help preventing decommissioning because of the IED limits.

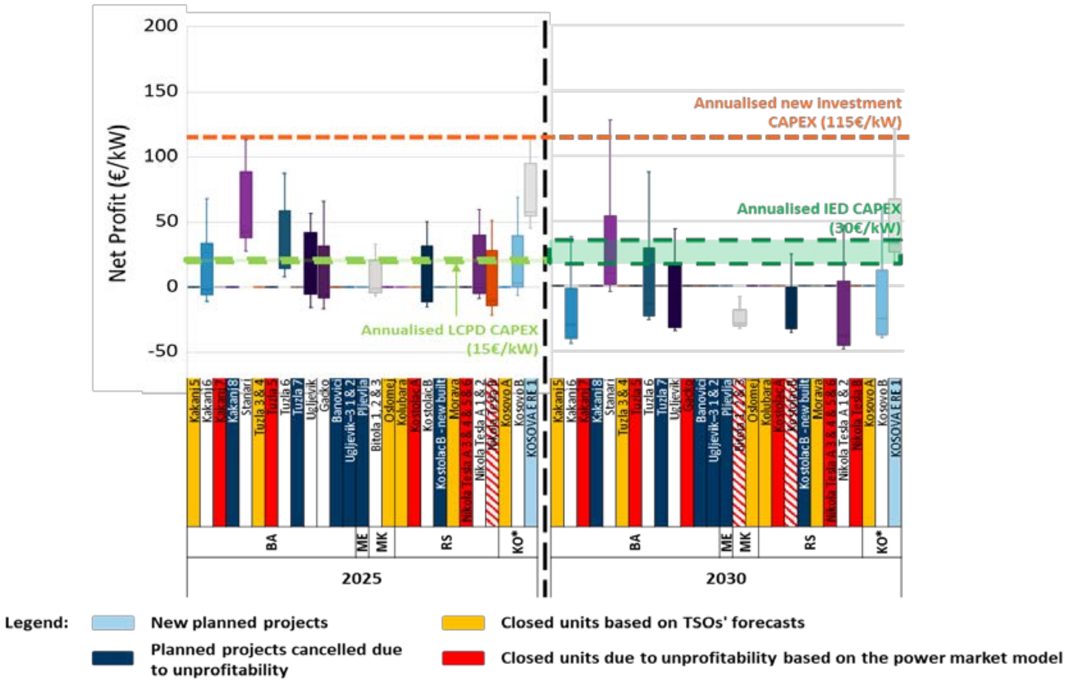
Market coupling efficiency sensitivity

4.91 To assess the sensitivity of the results of the EU ETS scenarios to cross-border availability, we design a sensitivity with constrained cross-border interconnection between WB6 and neighbouring countries. The constraints are defined in Appendix B.

<u>Profitability assessment of lignite plants in the constrained cross-border import sensitivity</u>

4.92 Figure 11 presents profitability results for years 2025 and 2030 under the EU ETS 2025 Energy Only scenario and with constrained cross-border import.

Figure 11: Net profit of lignite plants in the EU ETS 2025 Energy Only constrained cross-border flow sensitivity scenario



Source: *FTI-CL*

4.93 In this sensitivity analysis, and similarly to the previous unconstrained EU ETS Energy Only scenarios, new planned projects are not commissioned since they are expected not to be profitable. However, it can be noticed that fewer plants are decommissioned in the constrained cross-border flow sensitivity (for instance, the Nikola Tesla B unit still produces in 2025 and the Ugljevik plant does not close in 2030).

4.94 This can be explained by the impact of constrained cross-border flows on WB6 power prices: limitation of cross-border flows tends to increase WB6 power prices. Indeed, following the introduction of carbon pricing and the closures of several plants, the WB6 region starts relying on imports to meet its demand.

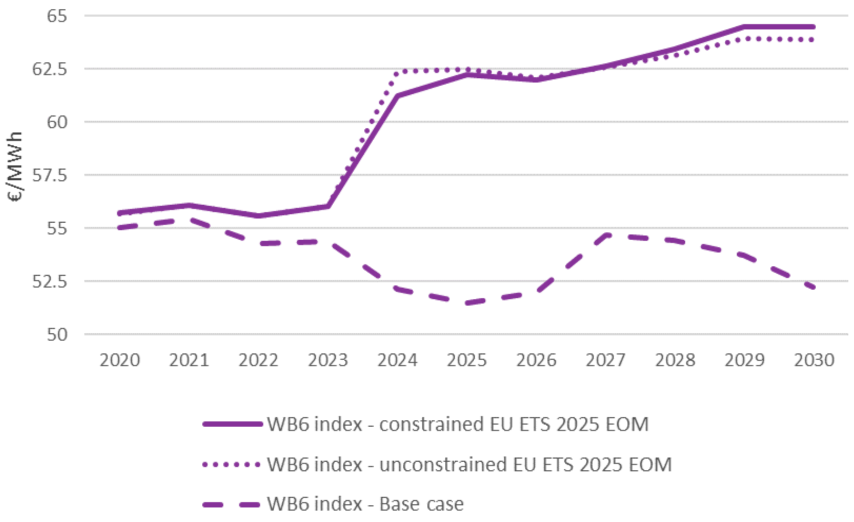
4.95 In the sensitivity analysis, given imports are limited, more expensive plants would be necessary to satisfy WB6 power demand. Power prices in the WB6 region increase, which improves the economic situation of remaining lignite plants compared to the previous unconstrained scenarios and reduces the number of decommissioned plants.

4.96 As a result, the long-term economic equilibrium in the constrained scenario shows fewer anticipated closure than in the unconstrained core Energy Only EU ETS scenarios. In particular, 2.5 GW are closed in late 2023, since they are not LCPD-compliant (compared to 3.1 GW in the unconstrained case) and 3.9 GW are closed in total by 2030 (compared to 4.4 GW).

Power prices outlook in the constrained cross-border import sensitivity

4.97 The resulting price outlook in the constrained cross-border EU ETS 2025 Energy Only scenario is illustrated on Figure 12 and compared with the unconstrained scenario.

Figure 12: Power prices outlook in the constrained cross-border EU ETS 2025 Energy Only scenario



Source: FTI-CL

4.98 Average prices in the WB6 region are similar between both scenarios: even if limited imports tend to increase prices in the WB6 region in the constrained scenario compared to the unconstrained one (all other things being equal), the lower number of lignite closures in the constrained scenario has a downward impact on prices compared to the unconstrained scenario (all other things being equal). These opposite trends explain why power prices are similar in both scenarios, at a level which enables existing plants to cover their costs.

Results of the adequacy assessment model

4.99 Once we have determined the capacity scenarios both in the base case scenario and the energy only market equilibrium scenarios, the associated adequacy performance can be assessed using the adequacy model. We present the associated results in this section.

4.100 To this end, the adequacy is assessed through two complementary methodologies: (i) an adequacy assessment based on the system margin; and (ii) an adequacy assessment based on the Loss of load Expectation (LOLE).

Adequacy analysis based on the system margin assessment

System margin assessment principle

4.101 The first approach aims at comparing demand and supply levels through a metric called the system margin. This method is used by several WB6 TSOs for their adequacy study (e.g. in

Kosovo*[93]) and can be easily implemented, with limited computation time (compared to the second methodology) as it compares the expected availability of the different technologies at peak time with expected peak demand. The system margin assessment does not account for all hours (but only peak hours) and does not consider the full 30 distinct samples of climatic years and random outages (see limits of this methodology in 4.114).

4.102 System margin is computed as:

$$\boldsymbol{System\ Margin} = \boldsymbol{Derated\ installed\ capacity} - (\boldsymbol{Peak\ Load} + \boldsymbol{Upward\ Ancillary\ Reserves})$$

4.103 Adequacy is assumed to be at risk whenever the margin is negative.

4.104 Peak load is defined as the peak demand that could occur under specific climate conditions (for instance 1-in-10-year risk). Upward reserves need also to be considered as they limit capacity available to generate electricity.

4.105 De-rated installed capacity differs from the net capacity since it accounts for the statistically expected level of generation at times of peak demand. For thermal plants, de-rated capacity is mainly reduced compared to the nameplate capacity to account for forced outages. For wind, solar and hydro technologies, their expected generation during peak hours is highly dependent on the availability of primary energy sources and derating factors reflect this availability distribution.

4.106 De-rating factors for all technologies, but hydro, are based on conservative values found in the literature (e.g. 88% for thermal plants, which means that on average 88% of the nameplate capacity is available during peak hours). For hydro plants, availability during peak hours is defined based on historical data for 2016, 2017 and 2018 for each WB6 country (more precisely, hydro de-rating is assumed equal to the average of past availability of hydro plants in 2016, 2017 and 2018 during the 100 hours of highest demand).

4.107 Table 4 provides de-rating values considered in the system margin analysis.

93 Cf. KOSTT, 2018, Plani i adekuacisë së gjenerimit 2019-2028. Available in Albanian at: http://www.kostt.com/website/images/stories/dokumente/tjera/Plani_i_Adekuacise_se_Gjenerimit_2019-2028.pdf

Table 4: De-rating factors assumed in the margin assessment

Technology	De-rating factor
Lignite	88%
CCGT	90%
Gas turbine	90%
Steam coal	88%
Oil	89%
Pumped storage	80%
Hydro AL	57%
Hydro BA	69%
Hydro MK	42%
Hydro ME	42%
Hydro KO*	28%
Hydro RS	72%
Wind onshore	15%
Solar	0%

Source: FTI-CL based on values considered in the British, French and Polish capacity markets

4.108 Moreover, available capacity should also include contribution of cross-border to adequacy thanks to import. Like for generation capacity, cross-border capacity should be derated to reflect their statistical contribution to adequacy during peak hours. Derating factors for cross-border are based on results of the market model: for each country, we assume a derating factor equal to the median of used import capacity during the 50 hours of highest demand (cf. Table 5).

Table 5: Assumed derating factor for import capacity

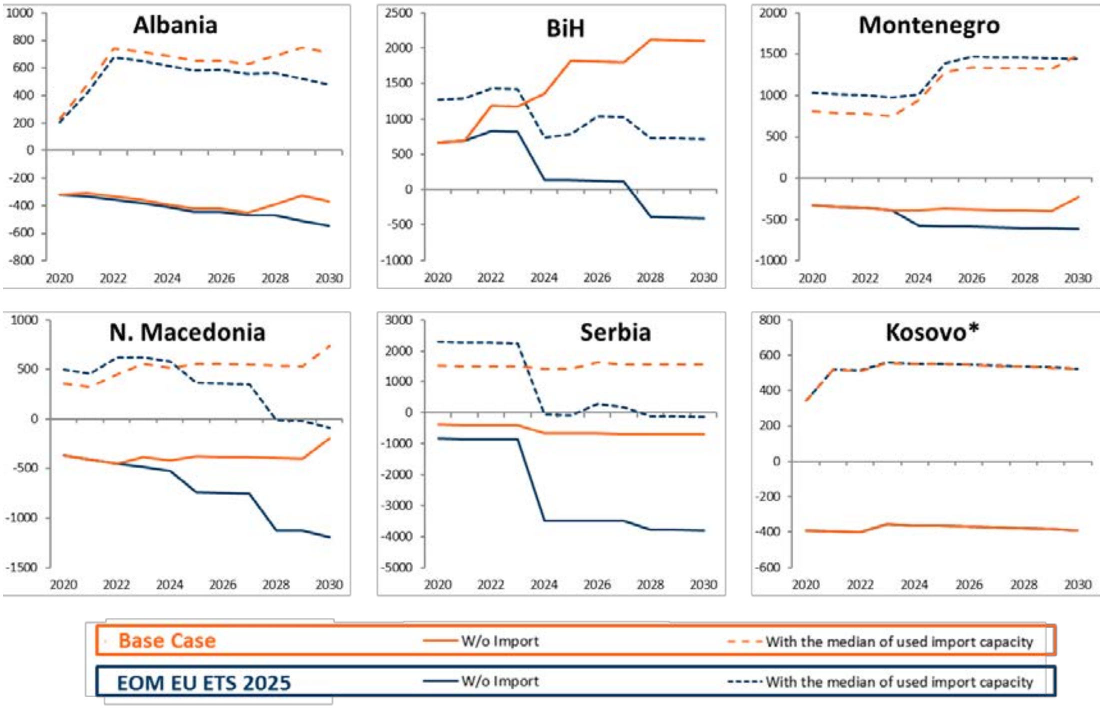
	Derating factor in the Base Case scenario	Derating factor in the EU ETS Energy Only scenario
Albania	58%	56%
Bosnia and Herzegovina	0%	33%
Kosovo*	50%	50%
Montenegro	49%	42%
North Macedonia	34%	40%
Serbia	46%	75%

Source: FTI-CL

System margin assessment results

4.109 Derated margin for each WB6 country is depicted on Figure 13 for the Base Case scenario and the EU ETS 2025 Energy Only scenario and in Figure 14 for the EU ETS 2030 scenario. Moreover, results are computed 1) without considering the contribution of import to adequacy, and 2) considering their contribution based of the median of used import capacity. A negative margin on the following charts highlights under security of supply concerns.

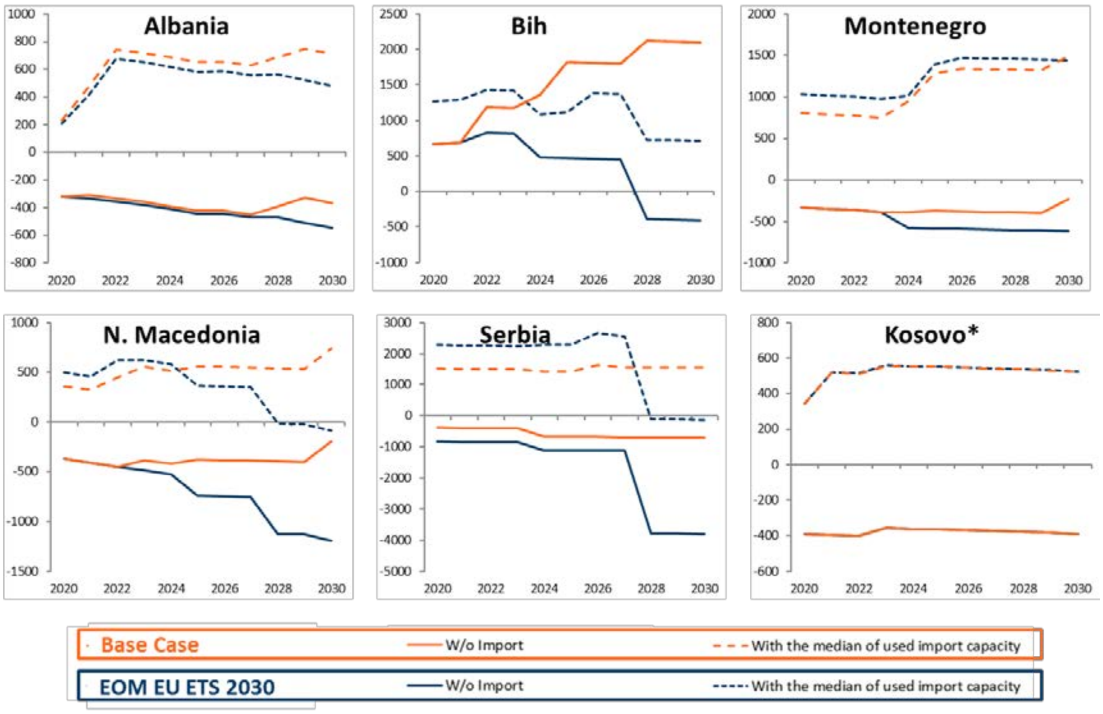
Figure 13: Derated system margin in WB6 Contracting Parties in the EU ETS 2025 Energy Only (in MW)



Notes: *For Bosnia and Herzegovina, both orange lines overlap since, in the Base Case scenario, the country does not rely on import during peak hours (contribution from cross-border lines is zero).*

Source: *FTI-CL*

Figure 14: Derated system margin in WB6 Contracting Parties in the EU ETS 2030 Energy Only (in MW)



Notes: *For Bosnia and Herzegovina, both orange lines overlap since, in the Base Case scenario, the country does not rely on import during peak hours (contribution from cross-border lines is zero).*
Source: *FTI-CL*

4.110 While the WB6 power markets are net exporter on an annual basis in the Base Case scenario, the system margin analysis shows that all WB6 Contracting Parties, but Bosnia and Herzegovina, rely on import capacity during peak hours to ensure security of supply[94]. It strengthens importance of cross-border interconnection in the region.

4.111 When studying the EU ETS Energy Only scenarios, system margin is significantly lower than in the Base Case scenario, especially in Bosnia and Herzegovina, North Macedonia and Serbia. This is explained by the low profitability of lignite plants, once they are subject to CO2 pricing, which results in cancelled investments and shutdown decisions. In particular, in 2030, margin is expected to be negative for all WB6 Contracting Parties in both EU ETS Energy Only scenarios when contribution from cross-border is ignored.

4.112 Except in Serbia, the situation improves in the EU ETS Energy Only scenarios when considering contribution from cross-border: based on the margin analysis, all countries but Serbia seem to avoid adequacy issues thanks to cross-border interconnections. In Serbia, even accounting for the contribution from imports, adequacy issues are expected.

4.113 Detailed country by country results are provided in Appendix C.

Limitations of the system margin assessment

4.114 The adequacy analysis performed above based on a system margin assessment gives first insights on the possible consequences of introducing the EU ETS market in the WB6 region. However, this method relies on several simplified assumptions (made in order to make the analysis less complex and time-consuming in terms on computation resources) which lessen the conclusions for the adequacy assessment:

- It considers each WB6 country separately: co-existence of tight situation is not perfectly considered, which means that one country can rely on imports from another country while the latter is also relying on import from the former at the same time;
- Stochastic simulations (random outages, several climatic years) are only implicitly considered through de-rating factors: concomitant outages on thermal plants are then not considered;
- Margin is computed during peak hours only (i.e. hours with the highest demand) whereas adequacy issues can occur during other challenging hours (for instance in case of outages or in case of low availability of hydro capacity);

94 For all countries but Bosnia and Herzegovina, the orange solid line is negative whereas the orange dashed line, considering import contribution, is positive.

- Loss of Load Expectation is not assessed and then cannot be compared with the security of supply target.

4.115 We address these limits with the second methodology presented in the next section.

Adequacy analysis based on the LOLE assessment

LOLE assessment principles

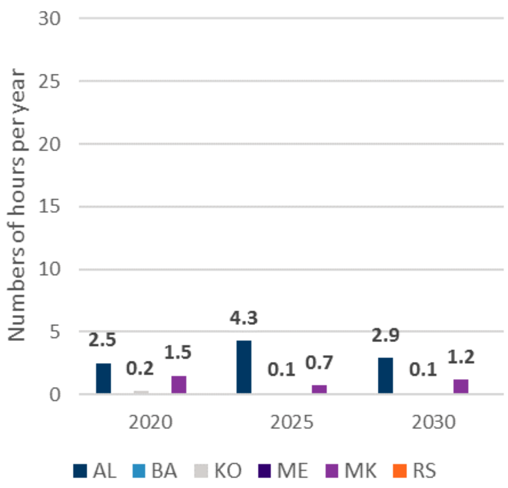
4.116 In the second methodology, we use our European power model in order to calculate the Loss of load probability (LOLP) of each country, by iterating through all units in the system, accumulating the unit outages and calculating their respective probabilities. Each of the outage states and their probabilities are entered into a capacity outage probability table and all the states are then convolved to determine the LOLP. LOLP also considers the contribution of import, which depends on potential excess capacity in neighbouring countries and possible coincident scarcity issues. Then, we calculate the LOLE (in hours per year) by multiplying the LOLP by 8760. LOLE quantifies the expected number of hours in a year during which power interruptions may be needed for some customers.

4.117 This second adequacy analysis gives relevant results to assess the adequacy situation in WB6 through the expected number of hours per year when demand cannot be fully met by generation and import. Contrary to the system margin assessment, it considers all hours (and not only peak hours), the full 30 distinct samples and adequacy is assessed simultaneously in all WB6 Contracting Parties.

LOLE assessment results

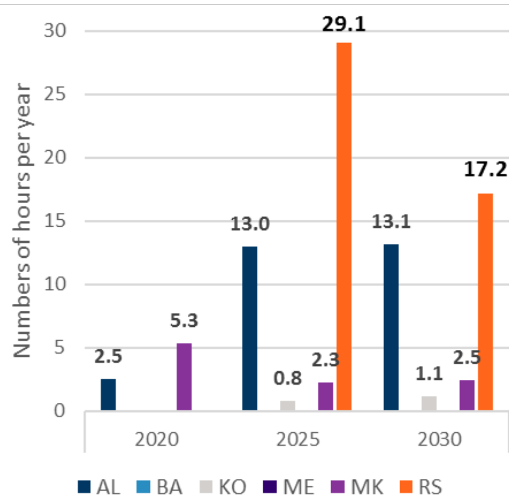
4.118 Results for the Base Case and EU ETS 2025 Energy Only scenarios are shown on Figure 15, Figure 16 and Figure 17.

Figure 15: LOLE for WB6 Contracting Parties in the Base Case scenario



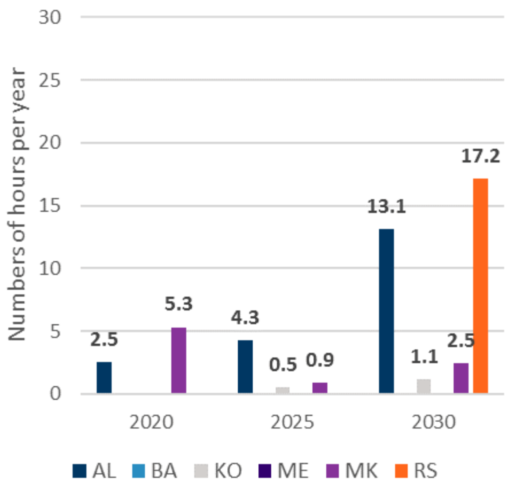
Source: *FTI-CL*

Figure 16: LOLE for WB6 Contracting Parties in the EU ETS 2025 Energy Only scenario



Source: *FTI-CL*

Figure 17: LOLE for WB6 Contracting Parties in the EU ETS 2030 Energy Only scenario



Source: *FTI-CL*

4.119 Assuming a security of supply target of 6-8 hours in all WB6 Contracting Parties, results highlight that there should not be adequacy concerns in the Base Case scenario thanks to investment in new and existing plants.

4.120 On the contrary, the EU ETS 2025 Energy Only scenario would result in significant security of supply concern as soon as 2025, in particular in Albania and Serbia due to (i) limited new investments in hydro (for Albania) and lignite (for Serbia) units, and (ii) closure of existing lignite plants (for Serbia).

4.121 The challenging situation of Serbia has been already detected with the system margin assessment. On the contrary, the LOLE assessment brings new conclusions for Albania. Indeed, adequacy issues were not identified in the previous derating margin analysis since they tend not to occur during the peakiest hours but when hydro availability is limited (given the importance of hydro for the Albanian system). Contrary to the LOLE assessment which studies the entire year, the margin analysis is limited to peak hours and is then unable to capture hours when hydro availability is low. Even if there are no lignite closures in Albania following the EU ETS introduction, the LOLE increases in the EU ETS scenarios given the closures in foreign countries which limit to what extent Albania can rely on imports during scarcity situations. Moreover, about 600MW of large hydro are not built in the Energy Only scenario, contrary to the base case scenario, since they are assumed not to be economic. It further worsens the adequacy situation.

4.122 The 2030 LOLE results for the EU ETS 2030 Energy Only scenario are identical to those of the EU ETS 2025 Energy Only scenario. In 2025, LOLE values in the EU ETS 2030 scenario are higher than in the base case scenario due to cancelled new investments but remain lower than in the EU ETS 2025 Energy Only scenario given that plants can make refurbishment investments to comply with LCPD and do not close.

4.123 Depending on the security of supply target, North Macedonia can also experience some adequacy issues in 2020. Like for Albania, there were not identified with the previous margin analysis. Indeed, the North Macedonian power system mainly relies on three 200-MW units (Bitola units), whose forced outage rate is 10%. The combined probability of 3 Bitola units being unavailable at the same time is not insignificant (≈9h/year), which can result in loss of load. This combined probability is properly taken into account with the LOLE assessment while the margin analysis is not able to capture this[95].

Conclusion

4.124 Further implementation of European regulation in the WB6 Contracting Parties would require alignment with the European target model (e.g. reforms of the wholesale market and market coupling), European environmental regulation (e.g. increased RES penetration targets, implementation of LCPD and IED and CO_2 pricing), and phasing out of existing State aid. Among these reforms, the EU environmental regulation (carbon pricing, emission directives) could significantly affect the profitability of coal and lignite power plants and could lead to anticipated economic closures or cancelled investment decisions. As a result, the reforms may lead to potential security of supply concerns as remaining available plants would not be sufficient to cover the increasing demand in WB6 Contracting Parties. Hence, we assess the impact of planned reforms on the power plant profitability and on potential future adequacy issues.

95 In the margin assessment, outages are considered thanks to de-rating factors. However, concurrent outages of several plants are not considered.

4.125 Among all planned reforms, we focus on the likely impact of EU environmental legislation (i.e. carbon pricing and implementation of LCPD and IED) on WB6 power plants, by comparing adequacy outlook with and without this legislation. In particular, in all assessed scenarios, we assume that (i) the EU target model is implemented in the WB6 region (e.g. fully competitive power markets, perfect market-coupling) and (ii) current State aids are phased-out (e.g. no complementary source of revenue beyond electricity market revenue, unsubsidised fuel prices).

4.126 Studied scenarios only differ by the implementation of carbon pricing and (ii) future environmental norms (LCPD and IED):

- **Base Case scenario** - based on TSOs' base case scenarios for capacity forecast based on TSOs studies and assuming no carbon pricing and incomplete impact of the future environmental norms (LCPD and IED);

- **Energy Only market scenarios** – considering that decisions for capacity investments and refurbishment are market based and that capacity needs to comply with environmental norms (LCPD and IED). We also assume CO_2 prices implemented from 2025 or from 2030.

4.127 In addition, we assess **two additional sensitivities** considering that WB6 Contracting Parties apply a transitional CO_2 price between 2025 and 2029 and limiting the import volume from neighbouring countries.

4.128 The key findings of the adequacy assessment are as follows:

Impact on capacity outlook for existing plants refurbishment decisions

4.129 Complying with LCPD by 2023 and to IED by 2028 would require existing thermal plants to refurbish and spend an additional annualised CAPEX of 15€/kW to meet LCPD and 30€/kW to meet IED. Combining (i) future investments in existing thermal generating assets necessary to comply with LCPD and then to IED with (ii) implementation of a carbon price would weaken the economics of existing carbon-intensive lignite plants in the WB6 region, thus leading to anticipated economic closure compared to the TSOs' base case assumption.

4.130 A full exposure to carbon pricing through EU ETS would make refurbishment investments to comply with LCPD and IED unprofitable leading to closure of more than half of the existing lignite capacity by 2030 compared to TSOs Base Case scenario (4.4 GW).

Impact on capacity outlook for on new plants investment decisions

4.131 Full implementation of a carbon price would also weaken the economics of new carbon-intensive lignite plants: new investments are expected to have a negative net present value, thus leading to limited new investment compared to the TSOs' base case assumption.

4.132 As soon as carbon pricing is introduced through EU ETS, new lignite plants would become unprofitable and would not be realized: 2.8 GW of new lignite projects are cancelled compared to the TSOs' base case assumption.

4.133 Furthermore, the wholesale power price level would not be enough to send robust economic signal to invest in alternative power production technologies within the energy only market design.

Impact on overall WB6 capacity evolution

4.134 As a result, WB6 lignite capacity would reduce by 7.2GW in 2030 compared to TSOs base case, of which 2.8GW of cancelled new investments, and 4.4GW of anticipated closure in late 2023 or late 2027 to comply with LCPD or IED.

Impact on security of supply

4.135 The gap of future investments in both new and existing plants in EU ETS 2030 Energy Only scenario and to a larger extend in the EU ETS 2025 Energy Only scenario would affect the future security of supply of WB6 power markets.

4.136 We find that in the Energy Only scenario, the number of hours of load curtailment per year (Loss of Load Expectation or LOLE) would largely increase as compared to the Base Case by 2025-2030. This is especially so for Serbia and Albania the LOLE will be significantly above a typical target level of LOLE of 6-8 hours:

- The challenging situation of Serbia is explained by the significant number of (i) cancelled new projects and (ii) closures due to adverse economic conditions to refurbish, which, combined, can threaten security of supply as soon as 2025 in the EU ETS 2025 Energy Only scenario, and in 2030 in the EU ETS 2030 Energy Only scenario.
- In Albania, adequacy issues can occur when hydro availability is limited, given the importance of hydro for the Albanian system. Cancelled projects and lignite closures in foreign countries worsen this situation by reducing the contribution of imports for Albania.

Sensitivity of transitional CO2 price between 2025 and 2029

4.137 The modelling results suggesting limited new investments and anticipated plant closure are highly dependent on the date of the full phase-in of the CO_2 price through EU ETS. In the CO2 sensitivity analysis, we assume that WB6 Contracting Parties implement a transitional CO2 pricing different from the EU ETS CO2 price, between 2025 and 2029 (a transition to full carbon EU ETS pricing is assumed by 2030). We assess what should be the value of this transitional CO2 price which would mitigate the impact on power plant closures.

4.138 We find that to incentivize refurbishment to comply with LCPD and mitigate anticipated closures by late 2023, the transitional CO2 price in the W6 region could be set up to 13-14€/tCO2 between 2025 and 2027, below the EU ETS CO2 price

4.139 However, given that the WB6 region is assumed to ultimately enter the EU ETS scheme in 2030, having a relatively low transitional price in 2028 and 2029 would not encourage investment in refurbishment to comply with IED since these costs must be recovered over 10 years. Consequently, the CO2 price in the WB6 region can increase from 2028 onwards to reach the EU ETS level in 2030 (assumed equal to 30€/tCO2). Having a transitional CO2 price in 2028 and 2029 would not help preventing decommissioning because of the IED limits. The adequacy issues observed in 2030 in the Energy Only scenarios are thus also likely to occur in the CO2 sensitivity scenario.

Market coupling efficiency sensitivity

4.140 The high degree of interconnection and the future implementation of market coupling will create significant interdependency between the WB6 Contracting Parties and with neighbouring countries. In particular, following the introduction of carbon pricing and the closures of several plants, the WB6 region starts relying on imports to meet its demand. Reduced imports from neighbouring countries, due to limited market coupling, can then impact the situation in the WB6 region. Hence, we perform a sensitivity analysis of the EU ETS 2025 and 2030 Energy Only scenarios by limiting the import volume from neighbouring countries, which mimics a potential inefficient use of cross-border capacity in absence of market coupling.

4.141 Limiting imports from neighbouring countries will tend to increase power prices in the WB6 region since more expensive plants would be necessary to satisfy WB6 power demand. As a result, the economic situation of remaining lignite plants is slightly improved compared to the previous unconstrained scenarios and fewer plants are decommissioned (3.9 GW are closed by 2030 as compared to 4.4 GW in the unconstrained scenario). However, like in the Energy Only scenarios, new planned projects are still expected not to be profitable, even with limited imports.

4.142 Limiting imports from neighbouring countries would lead to an inefficient power system for the WB6 region: it would require more expensive WB6 plants to be available and to produce to meet the peak demand in WB6 Contracting Parties. As a result, it would increase total costs for consumers. Moreover, it may create greater challenges for adequacy since WB6 Contracting Parties highly rely on import during scarcity events.

Section 5

Policy approaches to address the potential adequacy problem in WB6 Contracting Parties

Introduction

5.1 This section written by Compass Lexecon outlines potential solutions to the adequacy issues in WB6 identified in the previous section. In particular, the analyses of Section 4 suggest that potential adequacy issues in WB6 could result from the implementation of the EU Target Model for electricity, phasing out of existing state aid and transposing the environmental policies in the WB6 Contracting Parties (e.g. CO2 price and LCPD). The objective of this section is to explore the policy approaches that could be considered to ensure adequacy during this transition at the least cost to customers. According to the State aid regulation, measures allowed in the energy sector can address either environmental objectives, or security of supply objectives.

5.2 This section focuses only on the security of supply measures, such as Capacity Mechanisms (CM). We notice that given that one of the most critical drivers of the potential adequacy issues in WB6 is the introduction of the CO2 prices through EU ETS, it may be important to consider a gradual introduction of CO2 prices to avoid the negative shock on plants profitability and on the system adequacy. Potential mechanisms of gradual implementation of CO2 pricing that could be considered for WB6 include providing a decreasing number of free allowances to existing power plants for a transitional period as it was done in case of EU accession of Romania and Bulgaria. The EU carbon border tax that is considered to be introduced on the border with WB6 Contracting Parties could also serve as a transition for the CO2 pricing as it would introduce an implicit carbon pricing for the exports from WB6 Contracting Parties without impacting the cost of production of electricity consumed within the WB6 Contracting Parties.

5.3 Below, we proceed as follows:

- First, we summarise the specificities of the adequacy issues of WB6 that must be taken into account for the choice of a potential capacity mechanism;
- Second, we present the possible reforms and improvements of the energy-only market design to be pursued in WB6 Contracting Parties in parallel with the development of a CM; and

- Third, we analyse the drivers of the choice of Capacity Mechanism in Europe and derive the preferred high-level choice of a CM for WB6 to complement the policies aiming at reforming the market with the objective to ensure adequacy in the transition.

Specificities of adequacy issue of WB6 Contracting Parties

5.4 Based on the discussions presented in the previous Section 3 and Section 4 above, we consider that a number of specificities of the WB6 need to be taken into account when considering a CM. Below, we summarise the most critical ones:

- Resource adequacy situation in WB6 Contracting Parties; and
- High interdependency between WB6 Contracting Parties.

Resource adequacy situation in WB6 Contracting Parties

5.5 As shown in Section 4 above, at present, the WB6 region does not have resource adequacy issues and is not exposed to the likelihood of electricity supply shortage. However, the current adequacy situation can deteriorate as a result of various *acquis* requirements and reforms in relation to the further integration of the European energy target model. In particular, implementation of the Large Combustion Plan Directive (LCPD), the Industrial Emission Directive (IED) and the European Emission Trading Scheme ETS or another form of carbon pricing and phasing out of subsidies that are incompatible with *aquis* could reduce profitability of existing coal and lignite plants.

5.6 As a result, a number of coal plants can become not economic and may face retirement. Section 4 suggests that if a CO2 price is fully implemented in WB6 (from 2025 in the EU ETS 2025 Energy Only scenario or from 2030 in the EU ETS 2030 Energy Only scenario), there is a possibility for the lignite plants to suffer from significant losses. This would result in several lignite power plant closures, which are offset by higher imports from neighbouring countries making the WB6 region a net power importer.

5.7 In addition, the implementation of the CO2 pricing is expected to make investment in new generation unattractive, which on top of the closure of existing generation, would thus lead to potential security of supply concerns. As described in Section 4, a full introduction of a CO2 price, would make new and existing lignite plants unprofitable due to higher generation costs and relatively low market prices.

5.8 Even if net profit of new plants is still positive, it is well below the annualised CAPEX[96] threshold and therefore it expected that no rational economic actor would invest under such circumstances.

96 The annualized CAPEX is calculated using the rate of return of 7% specific to WB6 Contracting Parties, as described in Table 7.

High interdependency of WB6 power systems

5.9 The high degree of interconnection and plans for introduction of market coupling will create significant interdependency between the WB6 Contracting Parties. In this situation adequacy issues driven by the transposition of the environmental and carbon policies may have regional rather than national scope.

5.10 As presented in Section 4, adequacy in WB6 Contracting Parties during the peak hours critically depends on imports and the estimated adequacy issues originated in one country of WB6 would often induce the adequacy issue in neighbouring countries or across the region.

Market reforms to pursue in WB6 Contracting Parties in parallel with introduction of a CM

5.11 As discussed in Section 3, in WB6 Contracting Parties the electricity sector is still characterised by a significant involvement of the state and is heavily regulated. In such a context, capacity providers do not rely primarily on energy and ancillary services markets for investment decisions; these decisions are much driven by existing State aid.

5.12 A number of ongoing reforms are expected to align the WB6 electricity market with the European Target Model in the near future. These include:

- wholesale power market reforms;
- market coupling implementation within and with neighbouring EU countries (2019 between Italy and Montenegro; and 2020 between: Albania and Italy, Montenegro, Serbia; as well as Kosovo* and Albania);
- increased RES penetration targets; and
- as well as amendments identification related to the balancing and ancillary services.

5.13 The adequacy analysis of Section 4 is based on the assumption that many of these reforms are implemented, that WB6 electricity market is further deregulated and that capacity investors rely on the market prices of electricity that are formed in the competitive way reflecting the efficient use of the available interconnection capacity, and that a number of existing subsidies are phased out.

5.14 Once these reforms are implemented, the identified adequacy issues will be driven by the residual market failures typically leading to a so called “missing money” problem. Further reforms would be required to address the root causes of the “missing money” problem. We describe these below.

“Missing money” problem

5.15 In theory, in absence of market failures and regulatory interventions, adequacy should be achieved in the theoretical “energy-only” market paradigm. Electricity prices in markets from forward to real-time should provide a clear signal for plant investment and retirement. This would require electricity prices to correctly reflect the high value of energy in scarcity situations, achieving the Value of Lost Load (VOLL) that represents the value that customers place on security of supply.

5.16 In the long run, such prices should ensure an optimal level of reliability expressed in terms of a number of hours of load expected load curtailment per year (Loss of Load Expectation or LOLE). The long-term optimal level of LOLE is provided by the ratio between the cost of additional capacity or Cost of New Entry (CONE)[97] and the value of the loss of load (VOLL) for customers. In Europe the LOLE target is generally between 3 and 8 hours.

5.17 Below we present issues preventing this optimal economic equilibrium to be reached in the electricity markets and discuss whether and when these issues can be expected in the WB6 Contracting Parties.

5.18 There is growing evidence suggesting that in practice, power prices in energy-only markets do not provide adequate investment and retirement incentives. This happens because of a range of market failures and regulatory interventions that do not allow the energy price to reflect the actual value of energy for customers, especially, in the periods of scarcity. Such frictions are often the source of the "missing money" problem and include:

- **Inability of power prices to reach VOLL.** For a variety of reasons (ranging from operational price caps to the political unacceptability of very high-power prices), prices do not reach the VOLL in periods of scarcity, leading to a systematic revenue shortfall of plant operators. As seen on the graph in Figure 18. A price cap is introduced at the level of gas turbine (GT) variable cost which impedes the GT to earn enough profits in the energy market to cover fixed costs. Other generators may still be able to cover (part of) the fixed cost via the inframarginal rent (i.e. periods when market prices are higher than the marginal costs of the plant).

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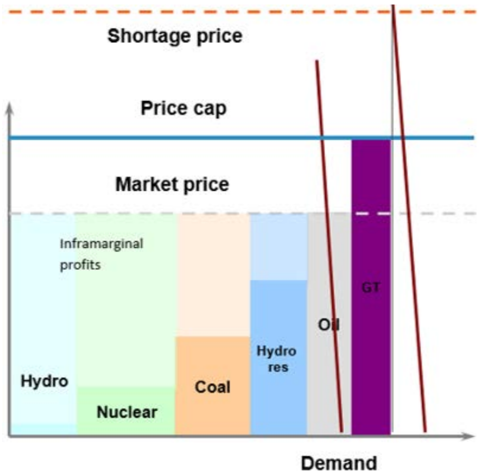
97 The Gross Cost of New Entry (CONE) represents the cheapest cost of a new entrant peaking plant. Gross CONE is the rental rate of the marginal peaking plant; that is the yearly amount of revenue needed to pay for capacity such that the discounted value (NPV) of its operations is zero over its technical operating lifetime, assuming the plant does not earn energy market revenue

Figure 18: Illustration of the "Missing money" problem



Source: FTI-CL Energy

- **Absence of active demand-side response (DSR) participation.** Customers that are not metered in real time still have little way to express their value of power at different times. This calls into question the rationale to rely on market forces to determine the adequate level of installed capacity and guarantee the security of supply.[98]

- **Inefficient designs of balancing and ancillary services.** These market segments may further contribute to the "missing money" problem, especially in cases when operating reserve scarcity is not reflected in the energy and ancillary services prices.

- **Increased penetration of subsidised renewable energy sources (RES)** could distort prices as they are deployed independently of power prices and market-driven capacity needs. The RES development induced by support schemes drive wholesale prices down by crowding out technologies with higher variable costs, such as coal and gas. Nonetheless, these sources may still be necessary to ensure security of supply, especially since variable RES have lower contribution to security of supply.

  Other policy and regulatory interventions. In addition to the market failures, a range of policy and regulatory interventions may further affect electricity markets and contribute to the "missing money" problem. This could involve out-of-the market technology support, mandatory decisions on plant closure, etc.

Further reforms to be pursued in the WB6 Contracting Parties

5.19 The need for a CM in the European electricity markets is justified by the "missing money" problem. That is, where investment in capacity resources mainly relies on revenues received

98 See e.g. LJ De Vries (2007). Generation adequacy: helping the market do its job. Utilities Policy 15 (1), 20-35 or Fabien Roques (2008). Market design for generation adequacy: Healing causes rather than symptoms, Utilities Policy, Elsevier, vol. 16(3), pages 171-183.

from the energy and ancillary services markets, there is a perception that the market failures mentioned above prevent efficient signals for investment in the absence of CM.

5.20 To ensure that the CM remains a temporal measure to address the "missing money" problem, the European Commission advises, in parallel with the introduction of a CM to prepare and submit an implementation plan for reforms of the energy market eliminating the regulatory distortions that caused the concerns, and to consider developing interconnections, energy storage, demand-side measures and energy efficiency. In general, such reforms may include the following:

- **Removing barriers for prices to meet VOLL.** The short-term markets should ensure that in periods of scarcity prices are not constrained from rising to reflect the value of electricity in such conditions. Scarcity prices are crucial for the efficiency of incentives for investments. Policies allowing price spikes during scarcity need to be effectively coordinated with the policies that are intended to limit the undue market power exercised by generators and thereby protect consumer welfare.

- **Foster DSR participation.** In the absence of active demand-side participation for load that is not metered in real time, market participants have no way to signal the value they place on power at different times. There are significant benefits in ensuring a level playing field between generation and DSR in all markets. Best practices in terms of product design need to be applied to avoid discrimination against DSR.

- **Ensure RES integration to minimise distortion of the markets.** A system with high shares of RES would have highly variable marginal cost and relatively high capital cost. The variable cost and the resulting energy price would often be low, when set by the marginal cost of RES. At the same time, the system may require an increased volume of flexible generation to offset the variability of RES. Making RES responsible for balancing their own output (for example, by selling it on the markets to counterparties or using it to supply load) would minimise the cost for their integration and impede possible market distortion.

- **Improve the design of balancing markets.** Effective balancing markets are essential if prices are to reflect scarcity and reward flexibility. Introducing marginal pricing and single price imbalance settlement in the balancing markets will provide a short-term price signal that represents the cost of balancing the system. This approach would remove the barriers to arbitrage between real-time balancing markets and markets for intraday and day-ahead trading and would allow scarcity to be better reflected along the forward curve.

- **Improve the design of the ancillary services markets.** The design of ancillary services markets should provide sufficient valuation for flexible resources. This could be done by implementing market-based hourly procurement of operating reserves. Procurement of reserves with the same frequency as energy or even their co-optimisation will improve the valuation of flexibility and the consistency of the scarcity price signal between balancing and operating reserve markets.

5.21 Despite addressing the root causes of the adequacy problem, market failures causing a residual “missing money” problem may remain. For example, in the case of highly interconnected markets, market failures can be “imported” from neighboring countries and affect adequacy in the given country. On the one hand, development and efficient use of interconnection capacity is key for WB6 generation adequacy. As shown in Section 4, in case available interconnection capacity is limited, Montenegro, North Macedonia, Serbia and Kosovo* may face adequacy issues at times of peak demand even without implementation of ETS. But on the other hand, high reliance on interconnection may result expose WB6 to “imported” market failures despite the internal market reforms.

The choice of a high-level CM model for WB6

5.22 Capacity mechanisms could be considered as measures to address the potential adequacy issues identified in Section 4 in 2025 to 2030 depending on the pace of the implementation of EU Target Model, environmental regulation and phasing out of existing subsidies.

5.23 Capacity mechanisms aim to address the security of supply problem in electricity markets by providing a separate revenue stream to some or all capacity resources that are necessary to meet the reliability standards. Below we discuss the drivers of the choice of a CM model in the European Member States and conclude on a potential choice of the CM model in WB6 Contracting Parties, once the conditions for the CM are met.

Classification of CM models according to European Commission

5.24 In 2016 the European Commission (EC) published their Final Report of the Sector Inquiry on CMs.[99] The EC 2016 Sector Inquiry defines Capacity Mechanisms as measures that enable revenues for capacity providers and thus, they may fall within the category of measures that can be subject to the Union’s rules on state aid. The EC Sector Inquiry defines two CMs categories in terms of the scope of CM application:

- **Targeted mechanism.** Targeted mechanisms only benefit specified capacity providers. The capacity mechanism provides support only to the additional capacity expected to be needed beyond what would anyway be brought forward by the market; and

- **Market-wide mechanism.** Market-wide mechanisms are in principle open to participation from all categories of capacity providers, including both existing and new providers of capacity.

5.25 In addition, the Sector Inquiry identifies two categories in terms of the main instrument of inducing capacity:

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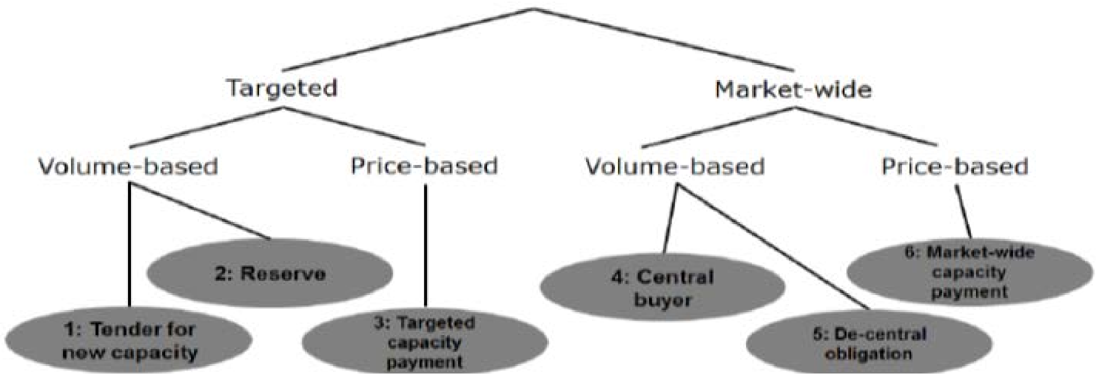
99 Findings of the EU Sector Inquiry apply to the Energy Community Contracting Parties to the extent that they show how the Energy Community State aid acquis and the EEAG ought to be interpreted and implemented.

- **Volume-based mechanisms**, where the capacity requirement is defined, and a capacity price will emerge through a market dynamic; the central buyer and de-central obligation models; strategic reserve and the tender models and

- **Price-based mechanisms**, where policymakers set the capacity price and let the market decide on the level of capacity – market-wide capacity payment.

5.26 This classification is presented in Figure 19 below.

Figure 19: Classification of Capacity Mechanisms under the EU definition



Source: *EC 2016, Final Report of the Sector Inquiry on Capacity Mechanisms. Commission Staff Working Document*

5.27 Combination of the categories provides three basic types of targeted mechanisms:

- **Tender for new capacity**. In this model the winner of the tender receives financial support for the construction of a power plant that would bring forward the identified top up capacity. Once the plant is operational, in some models the top up capacity runs in the market as normal (without a guarantee that the electricity will be sold). It would also be possible for the plant to be supported through a power purchase agreement.

- **Strategic reserve**.[100] In a strategic reserve mechanism, the top up capacity is contracted and then held in reserve outside the market. It is only run when specific conditions are met (for instance, when there is no more capacity available, or electricity prices reach a certain level). Typically, strategic reserves aim to keep existing capacity available to the system.

[100] In addition to the strategic reserves for generating capacity, the sector inquiry identified seven countries that operate specific schemes for demand response (usually large industrial users) that at first sight match the indicators for identifying a capacity mechanism: France, Germany, Ireland, Italy Poland, Portugal and Spain. Beneficiaries of such 'interruptibility schemes' are then held in reserve until required by the TSO. For this reason, these schemes can be regarded as a form of strategic reserve.

- **Targeted capacity payment**. In this model, the price of capacity is set centrally. This price is then paid to a subset of capacity operating in the market, for example only to a particular technology, or only to capacity providers that meet specific criteria.

5.28 Further, the Sector Inquiry identifies three basic types of market-wide mechanisms:

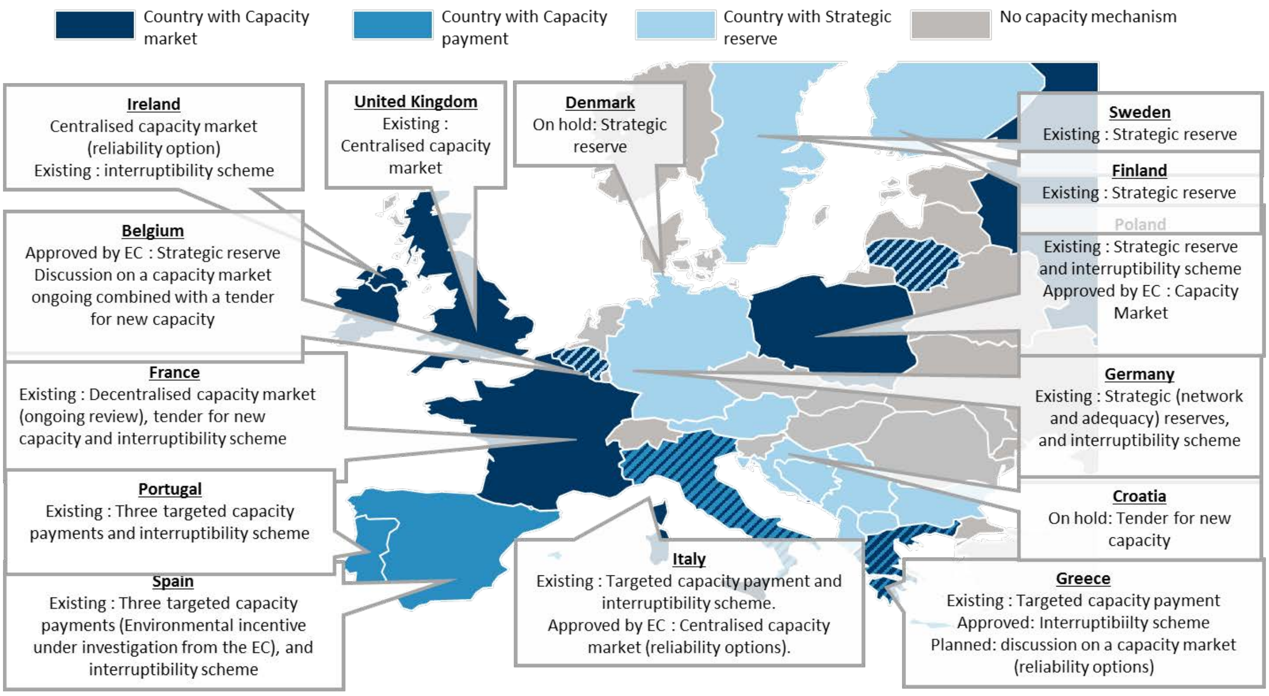
- **Central buyer**. Where the total amount of required capacity is set centrally, and then procured through a central bidding process in which potential capacity providers compete so that the market determines the price.

- **De-central obligation.** Where an obligation is placed on electricity suppliers to contract with capacity providers to secure the total capacity they need to meet their consumers' demand. The difference compared to the central buyer model is that there is no central bidding process, but market forces should still establish the price for the required capacity volume.

- **Market-wide capacity payment.** Where the price of capacity is set centrally, based on central estimates of the level of capacity payment needed to bring forward sufficient total capacity and then paid to all capacity providers in the market.

5.29 Figure 20 below illustrates the diversity of the capacity mechanisms introduced by European Member States.

Figure 20: Capacity Mechanisms in the EU Member States



Source: FTI-CL Energy

Drivers of the CM design choices across EU

5.30 In June 2019, the Commission adopted an updated Electricity Regulation 2019/943 (thereafter, 'Electricity Regulation'), as part of its Clean Energy Package. According the updated Electricity Regulation, two high-level design types are eligible for approval by the European Commission from the beginning of 2020: strategic reserve and a market-wide CM. The conditions for their application are as follows:

- **Strategic reserve**. In general, strategic reserves is an appropriate approach to prevent decommissioning of capacity that is necessary for adequacy according. States should assess whether their adequacy concerns are short term and if this is the case then they could consider the implementation of strategic reserve rather than market-wide CM.

- **A market-wide CM**. Where the adequacy concerns do not have a short-term nature and cannot be addressed by maintaining the existing capacity and require new investment, Member State may implement a market-wide capacity mechanism in a way that creates no distortions or limits cross-zonal trade, that is transparent, not-discriminatory and competitive, as well as, technology-neutral.

Country-specific drivers of the high-level CM model

5.31 The reasons driving introduction of capacity mechanisms in European countries vary from one country to another. They depend on the specific situation with respect to the prospects of capacity margin and the perceived need to induce investment in generation and demand-side resources (as well as to prevent necessary plants from retirement). However, several recent examples of choices of the CM model by Member States between strategic reserves and a market-wide CM are generally in line with the EU regulation, for example:

- In France, uncertainty of nuclear and mothballing of thermal capacity, peak demand growth, as well as low profitability of CCGTs also required a market-wide CM;

- Similarly, in Poland, substantial mothballing and phasing-out of thermal units expected by 2020, as well as capacity shortfall shortfalls experienced in 2015 and expected in 2020 and 2025 required new investments to be induced through a market-wide CM;

- In the case of Germany, significant excess thermal and RES capacity does not require support for new investment but rather requires preventing early retirement of existing power plants necessary for security of supply and for the relief of grid constraints from North to South due to large-scale roll-out of renewables combined with nuclear phase-out. This explains the choice of Germany to rely on strategic reserves for security of supply; and

- In Belgium, a strategic reserve was implemented to maintain existing capacity necessary to meet the winter peak, but since the nuclear phase-out will require new capacity investments, Belgium is currently migrating from a strategic reserve to a market-wide CM.

CO2 Emission Performance Standard for the Capacity Mechanisms

5.32 The possibility to support the existing plants under the new Electricity Regulation will also be an important driver of the high-level choice of the CM in the near future.

5.33 According to the new Electricity Regulation, carbon emission limits will apply to the capacity that is remunerated via a CM. In particular, the emission limit of 550 gram of CO_2 of fossil-fuel origin per kWh of produced electricity is put in place ('**550 rule'**). In EU Member States, this condition excludes new installations emitting more than 550 g of CO_2 per kWh of electricity immediately at the entry into force (i.e. 4 July 2019) of the EU Regulation. From July 2025, this condition excludes the existing installations emitting more than 550 g of CO_2 per kWh and 350 kg of CO_2 on average per year per KW of installed capacity.

The choice of a high-level CM model for WB6 Contracting Parties

5.34 As presented in Section 4, the implementation of the EU Target Model, emission standards, the introduction of carbon pricing through the EU ETS and the phase out of existing subsidies and State aid could raise material adequacy issues in WB6 Contracting Parties. Even though the introduction of EU ETS can be gradually phased in as discussed above, the risk of adequacy issues may remain and may need to be addressed by additional measures targeted on adequacy, such as a CM.

5.35 We stress that the policies considered in this section are no substitute for the implementation of sound market design and the continuation of market reforms which should be a priority focus in WB6 Contracting Parties; the policies discussed below are meant to complement the policies aiming at reforming the market with the objective to ensure adequacy in the transition.

5.36 Being considered by the EC as State aid, implementation of a CM needs to be justified according with the EU State aid rules and the criteria under EEAG as measures having the objective of contributing to security of electricity supply:[101]

- a reliability standard based on VOLL which should have served as basis for guiding any intervention in the market based on security of supply concerns;
- a clear definition of the precise security of supply objective which these measures aim to achieve;
- a preliminary detailed adequacy assessment, which would had identified the amount, type, duration and location of the capacity needs;
- a demonstration of the reasons why the market, also from the regional point of view, cannot be expected to deliver adequate capacity, through implementing planned reforms and/or investment in cross-border capacity; and

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101 See in particular paragraph (220) and (221) EEAG.

- considerations of alternative ways of achieving generation adequacy which would not have had negative impact on phasing out environmentally or economically harmful subsidies.

5.37 Below we outline the alternative high-level CM model options for WB6 Contracting Parties which comply with the framework set by the European Commission to evaluate the appropriateness of a capacity mechanism and respond to the specificities of WB6 Contracting Parties and their potential adequacy issues. In particular, we consider that a strategic reserve can address potential security of supply issues that could arise in transition to European regulation of the electricity sector and that a market-wide CM could be designed in parallel to be implemented when there is a need for new investment which may arise when the 550 rule is transposed in WB6 Contracting Parties making existing lignite and coal plants ineligible for CM revenues.

Strategic reserves

5.38 Given that the potential adequacy problems in WB6 Contracting Parties are related to possible retirement of existing capacity, to maintain generation adequacy in the transition towards EU ETS, WB6 Contracting Parties could implement a strategic reserve.

5.39 According to the EC, when adequacy concerns are driven by the risk of retirement of existing plants, a temporary strategic reserve may be appropriate intervention. SRs have been implemented in Belgium and in Germany to manage pace of thermal capacity decommissioning (further details on the design of the strategic reserves in Belgium and Germany are provided in Section 6). A similar adequacy issue could emerge in the WB6 Contracting Parties as a result of the transition to European regulation of the electricity sector.

5.40 The strategic reserve appears feasible in WB6 Contracting Parties until the 550 rule is transposed in WB6 Contracting Parties. The 550g CO_2/kWh and 350kg/kW/year Emission Performance Standard would exclude from the CM the existing lignite plants exposing them to the risk of economic decommissioning as a result of transition to the European regulation of the electricity sector.

5.41 We assume that in the Energy Community, the 550 rule should also apply to new plants immediately starting from the date of the entry into force of the Electricity Regulation for the Contracting Parties (i.e. presumably by 2020-2021). However, for existing plants, one could expect a transitory period of implementation of the 550 rule. Implementation deadline for the 550 rule to existing plants might be the same as the deadline for the general application of the IED and related BAT investments, i.e. by 2028, however this timing needs to be confirmed. We assume the definition of new and existing plants should be the same as under the IED. Until this moment, the existing plants that are at risk of decommissioning according to the adequacy analysis, can participate in the Strategic Reserves.

5.42 Since currently there are no CMs being officially implemented in the Energy Community,[102] the Energy Community shall not apply a grandfathering clause as the one at EU level art. 22(5) of the Electricity Regulation.

5.43 The strategic reserve requires a competitive process to identify the capacity providers that will provide reserve services. In general, successful bidders are paid the price they bid for the strategic reserve they provide, which usually includes a payment for being available and a separate activation payment. Strategic reserve capacity is kept out of the market for deployment in emergency situations only as defined by the TSO. Often, this reserve is made up of old plants which would otherwise be retired as uneconomical. When the strategic reserve capacity is dispatched by the TSO during times of scarcity, it becomes the price setting plant meaning the strategic reserve effectively acts as a price cap in the market, but in normal periods, strategic reserves do not affect the market.

5.44 The strategic reserve allows solving the anticipated adequacy problem at a lower cost as compared to the market-wide CM since the payments are limited to the strategic reserve capacity and not all capacity providers. However, this solution is bound to be temporal since the strategic reserve does not address the underlying market failures and correct the missing money problem only for those plants that patriciate in the scheme.

5.45 A well-designed strategic reserve does not distort the price signals in the day ahead and intra-day markets. The strategic reserve is relatively flexible in putting in place and removing when it is not needed. For example. If strategic reserve has not been activated during several peak situations, this could be an indicator of no further need for it.

5.46 More details about specific design elements and implementation of a strategic reserve and examples from existing markets are presented in Section 6 below.

Market-wide capacity mechanism

5.47 According to the European Commission, where structural long-term adequacy concerns and the need for new investment are identified, "*it is likely that the best way to address these is by of market-wide capacity mechanism*".[103]

5.48 The need to induce new investment in WB6 Contracting Parties may require a market-wide capacity mechanism. A number of European MSs have implemented such market-wide mechanisms in such situations (Poland, France, Italy, Ireland). Belgium is shifting from SR towards a market-wide as a result of the nuclear phase-out and need for new investment.

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102 Capacity payments under the Kosova e Re seem to not fulfill requirements for compatibility under the State Aid Guidelines 2014-2020. Furthermore, this project is not implemented and has yet not been constructed.

103 EC State Aid SA.45852 – Germany Capacity reserve

5.49 The transposition of the 550gCO2/kWh rule in WB6 Contracting Parties excluding existing coal and lignite capacity from CM could be another trigger for the transition from SR to a market-wide CM accounting for the specificities of the adequacy issues across the WB6 region (e.g. Serbian critical role).

5.50 In general, a market-wide capacity mechanism is the preferred approach when there is a significant need to both maintain existing capacity and attract new investment to replace ageing fleet or phase-out the existing capacity (e.g. nuclear or coal).

5.51 In a market-wide mechanism, all capacity required to ensure security of supply receives payment, including both existing and new providers of capacity. These mechanisms are in general technologically neutral and they are open for participation to all capacity resources contributing to adequacy, including DSR and RES as long as these capacity resources meet the CO2 emission performance standard.

5.52 The allocation of capacity is determined via a competitive process, such as a centralised auction. Remuneration granted through auctions is determined by the intersection between the supply and demand for capacity and therefore represents a market value. In the centralised auction, eligible capacity providers participate in a bidding process as suppliers and the auction operator determines the demand.

5.53 Further details about the design elements and implementation of a market-wide CM and examples from existing markets are presented in Section 6 below.

Regional cooperation

5.54 The European Commission requires a capacity mechanism "*other than strategic reserves and where technically feasible, strategic reserves*" to introduce direct cross-border participation of capacity providers located in another Member State. This means that any proposed measure for the WB6 Contracting Parties should implement explicit cross-border participation to ensure that the foreign capacity willing to patriciate in a neighbouring capacity mechanism has the opportunity to do so in the same way as the national providers.

5.55 Given the high interconnection of the WB6 Contracting Parties, implementation of cross-border participation should be expected to have a material impact on the efficiency of the chosen. Therefore, this element should be carefully considered in both a strategic reserve and in a market-wide models.

5.56 To implement the cross-border participation, regional TSOs are required to cooperate in order to coordinate allocation of cross-border capacity through non-discriminatory market-based solutions. Such regional cooperation could require establishment of regional political framework to guarantee security of supply in periods of stress and synchronisation of the reliability standards definition and adequacy assessment following on the existing Memorandum of Understanding between WB6 Contracting Parties: [104]

- **Coordination between TSOs on reliability standards** definition and adequacy assessment. A critical first step for a coordinated approach across neighbouring countries consists of defining explicit reliability standard criteria in each country (e.g. loss of load expectation or target reserve margin) and ensuring a consistent approach for adequacy assessments.

- **Regional policy, legal and operation framework** to deal with joint scarcity events. A regional framework for security of supply could be achieved through a regional or bilateral strategy with neighbours to define political, legal and operational frameworks to guarantee security of supply. Examples of the operational frameworks include: The introduction of a single price coupling algorithm EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm). The algorithm is used to calculate energy allocation and electricity prices across Europe; Coordination of the TSO operation through a regional platform CORESO to ensure secure operation of the regional high-voltage electricity system.

- **Agreements between TSOs on cross-border arrangements** of specific national CMs or to develop a regional CM. Explicit reliability targets are not guaranteed in the energy-only market arrangement. In case the WB6 Contracting Parties adopt an explicit reliability target in cooperation with neighbouring TSOs, introducing a regional capacity mechanism to guarantee this target may be suitable. Given the critical impact of interconnection between WB6 Contracting Parties, the implementation of explicit cross-border participation of neighbouring countries is important.

Conclusion

5.57 Potential adequacy issues in WB6 Contracting Parties could arise as a result of the implementation of the EU Target Model for electricity, phasing out of existing state aid and transposing the environmental policies in the WB6 Contracting Parties (e.g. CO_2 price and LCPD/IED). Various transitional approaches could be considered in the introduction of CO_2 prices to avoid the negative shock on plants profitability and on the system adequacy.

5.58 Once these reforms are implemented, capacity investors would primarily rely on the market prices of electricity that are formed in the competitive way reflecting the efficient use of the available interconnection capacity. The identified adequacy issues will be driven by the residual market failures known as the “missing money” problem. The “missing money” problem is likely to remain even though the WB6 Contracting Parties would further pursue the reforms

[104] See Memorandum of Understanding of Western Balkan 6, ‘On Regional electricity market development and establishing a framework for other future collaboration in South East Europe’, signed on 27 September 2016, (‘WB6 MoU’).

to address the market and regulatory failures in electricity markets leading to the “missing money” problem.

5.59 Therefore, State aid measures ensuring security of supply may need to be considered in WB6 Contracting Parties both in transition and as a more structural feature of the new market design. The new EU regulation defines as eligible design types of CM to be Strategic Reserves as a temporal solution to prevent decommissioning of existing capacity and a Market-Wide CM in case if there is a long-term need to induce new capacity. Given the specificities of the adequacy issue of the WB6 Contracting Parties, both high-level CM models could be considered in WB6 Contracting Parties:

- A Strategic Reserve model appears as a possible first option for WB6 Contracting Parties to maintain generation capacity needed for adequacy in transition to European regulation on the electricity sector. The existing plants that are at risk of decommissioning according to the adequacy analysis, could participate in a strategic reserve. The strategic reserve approach is more suitable for preventing the economic closure of the power plants, but it may still be used to support new investment or significant refurbishment of plants..

- A Market-Wide model could be necessary for WB6 Contracting Parties to support investment in new capacity and/or to refurbish existing units after the 550 rule is transposed in WB6 Contracting Parties. In a market-wide mechanism, all capacity required to ensure security of supply receives payment, including both existing and new providers of capacity. These mechanisms are in general technologically neutral and they are open for participation to all capacity resources contributing to adequacy, including DSR and RES as long as these capacity resources meet the CO2 emission performance standard.

5.60 The strong emphasis of the new Electricity Regulation on the cross-border participation and the high interdependency between WB6 Contracting Parties may require a regional approach with at cross-border participation in national CMs or a regional CM. Such approach would require a number of political decisions and coordination among political decision-makers, regulators and TSOs to develop a regional framework for security of supply: (i) between TSOs on reliability standards assessment; (ii) between national authorities and TSOs on regional policy, legal and operation framework; (iii) between TSOs on cross-border arrangements.

Section 6

Implementation issues of capacity mechanisms

Introduction

6.1 This section written by Compass Lexecon summarises the details on the two CM models discussed in Section 5 above: Strategic Reserve and Market-Wide CM, based on the existing examples of these mechanisms in Europe. In particular, in this section, we:

- First, provide an overview of EU State aid guidelines according to which a capacity mechanism should be design in order to comply with EU requirements; and
- Second, present the choices of the implementation design of centralised market-wide capacity mechanisms; and
- Third, present the implementation design elements of strategic reserves.

EU State aid guidelines

6.2 Considering the Capacity Mechanisms as State aid, the European Commission sets a framework to evaluate the appropriateness of a capacity mechanism. We present this framework below and outline the role of cross-border participation.

6.3 In order to determine whether a capacity mechanism should be implemented, the European Commission has developed a set of guidelines for the design of CM to ensure their compliance with State Aid regulations.[105] These guidelines can be grouped into three main categories as follows.

- **Justification.** It should be demonstrated that the proposed measure for capacity mechanism contributes to a well-defined objective of common interest. The objective of the measure needs to be clearly defined and consistent with adequacy analyses carried out by ENTSO-E and not contradict the objective of phasing out environmentally harmful subsidies including for fossil fuels. It should be demonstrated that in the absence of any intervention, security of supply would be endangered. Current market failures that are the source of the problem should be identified and it should be demonstrated how they will be

105 In particular, the 2014 Guidelines on State Aid for Environmental Protection and Energy.

resolved in the long term. The Commission will pay close attention to the impact of RES development, but also to remaining regulatory and market failures as well as measures to encourage DSR and projects to develop interconnection.

- **Design.** The proposed measure should be open to both existing and future generators, as well as other technologies, such as storage or DSR. The proposed measure should implement explicit cross-border participation ensuring that the foreign capacity willing to patriciate in a neighbouring capacity mechanism has the opportunity to do. The proposed measure should provide remuneration to the minimum by implementing a competitive bidding process so that the price paid reduces to zero when the level of capacity supplied is expected to be adequate. Generators may be remunerated for committing to be available (in €/MW) but not for the sale of energy (in €/MWh).

- **Impact on competition and internal market.** The proposed measure should have a limited impact on the energy market, avoid market distortions and the use of market power by dominant generators. The proposed measure should have no influence on the participation (e.g. dispatch or bidding behaviour) of operators in energy markets. The measure should not reduce incentives to invest in interconnection or undermine generation investment decisions preceding the measure.

6.4 As already discussed in 5.30 according the new Electricity Regulation, there are two preferred design types eligible for approval by the European Commission from the beginning of 2020 – strategic reserve and market- wide capacity mechanism. In the following subsections we outline in detail the design elements of each type and their variations across EU.

Market-wide capacity mechanisms

6.5 As described in Section 5, market-wide mechanisms are in principle open to participation from all categories of capacity providers, including both existing and new providers of capacity, who also are allowed to patriciate in the energy market if they clear in the capacity market. The two main types of market-wide capacity mechanism are:

- **Centralised**, where the total amount of required capacity is set centrally by the TSO, and then procured through a central bidding process in which the cleared clearing price is paid to all participants who cleared, and

- **De-centralised**, where an obligation is placed on electricity suppliers to contract with capacity providers to secure the total capacity and the demand is defined by the capacity providers without relying on a central bidding process.

Design elements of the centralised market-wide capacity mechanisms

6.6 A number of European Member states have implemented such market-wide mechanisms: GB, Poland, France, Italy, and Ireland. Belgium is currently from SR towards a market-wide as a result of the nuclear phase-out. With the exception of France, all the European market-wide CMs feature a centralised approach. Below we outline the design details of centralised market-wide CMs with focus on:

- **Eligibility.** Eligibility defines what types of capacity are eligible to participate in the capacity mechanism and under which conditions. They tend to be open to all types of capacity, including DSR, RES, and foreign capacity but specific conditions may apply. For example, technologies benefitting from other forms of support, such as RES may be limited in their participation in the CM. Also, technologies such as DSR that cannot compete on a level playing field with other technologies due to market failures, specific technical characteristics or limited participation in the energy markets may receive support in participation in the CM. The recent Electricity Regulation excludes capacity emitting more than 550gCO2/kWh from receiving capacity payment from 2025.

- **Qualification.** Qualification (also defined as "certification" and "pre-qualification") is performed by the system operator to ensure that contracted resources are actually capable of meeting their obligations. This is performed as a precondition for participation to the mechanism. During the qualification, plants can decide to opt out, in particular if they expect to close or to be mothballed, but measures are taken to ensure such opt-out does not represent capacity withholding with purpose to impact the capacity price. The qualification process is also used to define the de-rating factor of representing the actual expected contribution of the capacity to the adequacy target. De-rating takes into account maintenance needs or unavailability factors and is particularly significant for renewables because of their intermittence and for storage because of its limited availability to contribute during the stress events. Several de-rating methodologies are applied in Europe.

- **Capacity requirement.** The capacity requirement should be based on a robust adequacy analysis considering different scenarios and be as consistent as possible with ENTSO-E's Mid-term Adequacy Forecast (MAF). The required capacity is set at the level of de-rated capacity that is expected to be needed to reach the reliability target (e.g. 3h or 8h LOLE). In the centralised capacity market CM, the required capacity is allocated via a competitive centralised auction based on a demand curve for capacity defined by the TSO.[106] In the European CMs, a sloping demand curve is defined in order to mitigate market power (to avoid capacity withholding), increase the economic efficiency (if capacity becomes more expensive, less capacity is bought) and reduce volatility of capacity price. In addition, a price cap is always enforced to avoid market power abuse.

- **Bid selection and auction pricing.** The design of the capacity auction, the way the bids are selected and the clearing price is defined are important for the efficiency of the allocation process and for ensuring appropriate and clear signals for investment. The bid selection defines the process of how participants submit their bids and how the successful bidders are identified. Amongst the various types of auction mechanisms, sealed-bid

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106 Except in France, where the CM capacity requirement is decentralised.

auction[107] and descending-clock auction[108] are used for CMs. The auction pricing defines the price that each successful player will receive. There are two types of auction pricing mechanisms: pay-as-clear and pay-as-bid; the former is generally the preferred option as it reveals the capacity value at the auction, fosters efficient bidding while providing revenues above avoidable costs to finance fixed costs / investments.[109]

- **The timing of the auction** defines how long before the delivery year the auctions take place. Main auctions occur 4 of 5 years ahead, so that new plants (whose development and construction lead time is generally several years) to participate and compete with the existing plants. At the same time, longer auction lead time create more uncertainty in terms of reaching the adequacy target (target capacity is based on the forecast that is all the more inaccurate as it is made in advance). To manage this uncertainty, additional auctions are often organised one year ahead of the delivery year.

- **Bidding restrictions** define the principles of setting the bid caps that are often set for existing capacity to limit their market power and avoid excessive profits (in particular, when new plants are not needed to reach the capacity requirement). Bid caps should allow existing plants to bid up to the actual level of their missing money and exemptions from bid cap are often possible for existing plants in case they justify particularly high costs (in particular in case of refurbishment).

- **Capacity obligation** define obligations imposed on capacity availability during the delivery period allowing capacity providers receive the capacity payment and the way availability is enforced. The two most common types of obligations are Reliability Option (RO) and Capacity Obligation. A capacity provider that has sold a RO will be required during the delivery year to pay back to the CM operator the difference between the market reference price and a strike price whenever this difference is positive. The need to pay back the

107 In the sealed-bid auction, each bidder places a bid with the price at which it is ready to sell its capacity. The auctioneer gathers all bids, creating an aggregate supply curve, and matches it with the quantity to be procured. The sealed-bid auction is easy to implement, and the cost of participation tends to be lower than in more complex auction designs. Also, this type of bid selection process is preferable in the case of weak competition as it limits information asymmetries and potential for gaming and collusion.

108 In the descending clock auction, the auctioneer starts by calling a high price and asking bidders to state the quantities they wish to sell at such a price. If the quantity offered exceeds the target quantity to be procured, the auctioneer launches a new round at a lower price, and again asks bidders the quantities they want to offer at the new price (and so on). Bidders can adjust their bids based on information revealed throughout the auction, improving the efficiency of the auction. At the same time, when competition is not very strong, revealing excessive information can provide bidders information them to coordinate their bidding, increasing the final price of the auction.

109 Pay-as-bid may be preferred together with specific monitoring and if there are specific classes of assets with strategic advantages and entry barriers, to avoid high rents and costs for consumers, however pay-as-bid models are rarely favoured in an auction for a homogenous product such as capacity.

difference between the Strike Price and the Market Reference Price serves as an implicit penalty enforcing availability obligation in the RO.[110] Under a Capacity Obligation, availability obligation is enforced with explicit penalties for unavailability inducing capacity providers to be available in stress events. Unavailability is assessed both during the stress events when they occur and using random checks in absence of stress events.

- **Contract duration** defines the duration of a capacity contract offered in the auctions to capacity providers. By default, the capacity contract duration is one year, but all European CMs recognize the need for longer capacity contacts for capacity requiring significant investment costs (e.g. investment in new capacity or refurbishment of existing capacity). Long term contracts reduce the risk premiums and make financing of the capital-intensive projects easier. The contract duration is often set in relation to CAPEX necessary for the capacity to be available during the delivery year. Contracts of 2 to 5 years are awarded to plants with moderate level of new CAPEX, e.g. refurbished plants. New plants with high capital expenditure are often eligible to 10 – 15-year capacity agreements.

Cross-border participation

6.7 The EU regulation makes a specific focus on the participation of the foreign capacity providers in national CMs. The CM cross-border participation does not affect in any way the capacity allocation process set by the Day-ahead and Intra-day energy markets. The EU Regulation 2019/943 sets the conditions for cross-border participation (‘Target Solution’) in capacity mechanisms in accordance with the following categories:

- **Entry capacity calculation**: Entry capacity defines how much capacity can be provided through the interconnection. Calculation is required for each biding zone and will account for both availability of interconnection and coincidental stress events. Based on the results of the calculations, the national TSOs will set the maximum entry capacity available for the participation of foreign capacity in the CMs.

- **Market-based allocation**: The Regulation requires the selection of all capacity providers (including foreign) to be done via competitive process, e.g. an auction preceding the main CM auction.

- **Congestion rent:** Market-based allocation of entry capacity may generate revenues for the TSO operating the CM. If there are CMs open for cross-border participation in two neighbouring Member States, any congestion rent shall be shared between the two TSOs. The methodology for sharing will be developed by ENTSO-E. However, if no CM in the neighbouring country than “*the share of revenues shall be approved by the competent*

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110 Other attractive properties of RO are that its design is more compatible with retaining short-term energy price signals, whilst providing a long-term hedging instrument. However, CM based on Reliability Option requires setting additional parameters including Strike price and Market Reference Price, making implementation of RO more complex.

national authority of the Member State where the capacity mechanism is implemented after seeking the opinion of the regulatory authorities of the neighbouring Member States."[111]

6.8 There are currently no regional market-wide capacity mechanisms in place across Europe, but a zonal CM model approved by the EC in Italy or zonal CMs in the US (PJM, New York, and New England) could be considered as potential regional models of a market-wide CM possibly considered for WB6 Contracting Parties. The general principles of regional CM approach are the following:

- Capacity requirement and the demand curves are defined individually for each `zone,
- Transmission capacity available between zones for the purpose of the regional CM is calculated based on the interconnector availability and coincident stress events in a way similar to the de-rated entry capacity envisaged in the explicit cross-border participation,
- A joint capacity auction simultaneously clears the capacity bids in all zones taking into account the contribution of transmission capacity,
- Different capacity prices are determined across bidding zones in case transmission capacity is binding.

6.9 Implementation of such a regional CM would require a different level of coordination between TSOs with respect to synchronisation of the auctions and having a regional body to run the regional auction.

Strategic Reserve (SR)

6.10 As outlined in Section 5, the Strategic Reserve is the top up capacity contracted and then held in reserve outside the market. It is only activated when specific conditions are met, e.g., when there is no more capacity available, or electricity prices reach a certain level.

6.11 Strategic Reserve is an appropriate CM model to manage pace of plant decommissioning. According to the EC, when adequacy concerns are driven by the risk of retirement of existing plants, a temporary strategic reserve may be an appropriate intervention. In Europe, recent examples of Strategic Reserves introduced to manage the decommissioning of thermal plants are Belgium and Germany. A similar adequacy issue could emerge in the WB6 Contracting Parties as a result of introduction of emission standards and EU ETS.

6.12 Below we outline the design choices of a Strategic Reserve:

- **Eligibility** defines the type of capacity that can patriciate in the Strategic Reserve and receive remuneration. The SR tenders could be open to all types of domestic capacity providers including generating plants, storage facilities and demand response operators,

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[111] Regulation 2019/943

provided they fulfil a number of technical requirements (e.g. star up time, a minimum partial load). However, capacity providers providing SR are not allowed to sell their reserve capacity in the electricity market. Capacity providing SR should intend to close temporarily or definitely and are not allowed to return to the market once their SR contract ends (‘no return clause’). For operators of demand response, the ‘no return clause’ does not apply.

- **Capacity requirement** defines the approach used to calculate the volume for the strategic reserve. The volume is determined in accordance with the following steps. First, probabilistically analysis of the resource adequacy outlook is implemented, requiring evaluation of the forward availability of generation facilities and of the evolution of demand for electricity. Second, the periods of structural shortage are identified, i.e. time periods when the generation of electricity is insufficient to meet demand. Third, the strategic reserve volume is determined as the volume necessary to meet the adequacy targets given by law.

- **Bid selection and auction pricing** defines the process in which participants submit their bids and successful bidders are identified. Capacity providers generally bid for the yearly remuneration they wish to receive for maintaining their capacity available, up to a certain price cap and are selected on the basis of their bid until the demanded overall volume is met. The capacity providers that are successful in the tender receive remuneration in the amount of the highest successful bid submitted in the tender (‘pay-as-cleared’).

- **Testing and penalties** defines tests that the TSO runs to verify the eligibility of the capacity providers and penalties in case the plant fails to perform. TSOs carry out functional tests for each installation before it enters the strategic reserve, so as to verify that it meets the technical requirements. These tests include activation of the plant for a period several hours at the full reserve power. Where the test demonstrates that a facility does not meet the requirements, a penalty is applied. Furthermore, TSOs can implement trial calls of the strategic reserve installations with the full reserve output for a period of several hours without notifying the operator in advance. In addition to these “availability penalties”, “activation penalties” are also applied when participants fail to activate or fail to follow the precise activation instructions when called upon by the TSO (MWh-based penalties).

- **Activation rules** define the circumstances under which the Strategic Reserve would be activated. E.g. the Strategic Reserve can be dispatched when the market does not clear, i.e. when there is insufficient supply to meet demand. The market is considered not to have cleared when on the day ahead or on the intraday market bids at the technical price limit (e.g. 3,000€/MWh for the day-ahead market and 10,000€/MWh for the intraday market in Germany), are not fully met within one hour by offers to generate. Otherwise, the reserve can be activated after the day-ahead market for a given period or in the course of the day, if the TSO identifies a ‘structural shortage risk’.

Regional strategic reserves

6.13 In the case of Strategic Reserve, the Commission states that: “*In the future, the design of strategic reserves may adapt, and as energy markets become more regional it would also be* *possible to design more regional strategic reserves that might overcome the limitations of current designs*."[112] Even where designs mainly remain national, where neighbouring Member States are open to the participation of their capacity resources in a neighbour's strategic reserve (i.e. where they would accept capacity being removed from the local market for use only in a concurrent stress event to the benefit of the neighbour), the Member State creating the reserve could make arrangements to include this cross border capacity in the competitive process for establishing the reserve.

6.14 There are currently no regional strategic reserves in place across Europe. However other regions such as the Nordic region have considered the regional approach, but besides market analyses[113] and evaluation, no further steps have been taken to the best of our knowledge.

Conclusion

6.15 Considering the Capacity Mechanisms as State aid, the European Commission sets a framework to evaluate their appropriateness. The framework includes three main categories of criteria: (i) justification for the measure, (ii) design of the different elements of the measure, and (iii) potential impact of the measure on the competition and internal market.

6.16 According to the State aid design framework, as well as the updated Electricity Regulation, there are two preferred design types eligible for approval by the European Commission from the beginning of 2020 – strategic reserve and market – wide capacity mechanism.

6.17 Once Member States have assessed their generation adequacy and decided to introduce a one of the two preferred capacity market schemes, they face a range of choices to design a suitable capacity mechanism to address the identified adequacy problem. There are a number of considerations to be made in accordance with the specificities of the individual electricity markets. The most important of those design choices include (i) who gets to participate in the capacity mechanism; (ii) how does the selection process among the eligible parties work and how is the level of capacity remuneration determined; (iii) what do participants in the scheme have to do, and what happens if they don't do it. For each of those design features we provide examples from existing European capacity mechanisms of the two models: market-wide capacity mechanism and strategic reserve.

6.18 For both high level capacity mechanisms, the EU Regulation requires that foreign capacity providers can explicitly participate in national capacity mechanisms and receive capacity revenues. Although these cross-border arrangements are still under development, the principles of such arrangements are:

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112 Sector Inquiry, (page 202)

113 https://norden.diva-portal.org/smash/get/diva2:1039397/FULLTEXT01.pdf

https://www.poyry.com/sites/default/files/media/related_material/nordicmarketdesign_finalreport_v200.pdf

- calculation of the capacity requirement for each zone to meet the reliability standard based on adequacy analysis;

- assessment of the volume of transmission import capacity that can contribute to the capacity requirement accounting for coincident stress events between the market zones;

- organisation of a pre-auction to pre-select foreign capacity for participation in national capacity auctions and

- allocation of the congestion rent arising when the supply of foreign capacity exceeds the entry capacity of the given interconnector.

6.19 A further step in the regional coordination of capacity mechanisms could be a mechanism of joint capacity allocation mechanism consisting in setting individual capacity requirements in different zones and simultaneously solve all requirements in a single auction taking into account the contribution of transmission capacity and setting different capacity prices across bidding zones in case transmission capacity is binding. General principles of the such regional capacity mechanism can be illustrated on the examples of zonal capacity market designs in Italy and US.

Appendix A

FTI-CL Energy power market model

Introduction

A.1 This appendix presents the details of FTI-CL Energy power market model used for the adequacy and economic viability analysis of WB6 electricity market.

A.2 Our European Power Market Model is implemented in the commercial modelling platform Plexos® Integrated Energy Model. This modelling platform is most commonly used in the European electricity industry by utilities, regulators and transmission system operators. Plexos® allows finding solutions quickly using advanced optimisation procedures taking into account of a large number of variables and complex constraints of transmission network and power plants. It also provides a flexible and user-friendly interface allowing testing multiple scenarios, to perform stochastic sampling and optimisation, and to present the results in a graphical form.

A.3 The dispatch model covers the EU-28 countries, including the United Kingdom, Ireland, France, Belgium, the Netherlands, Germany, Austria, Luxemburg, Italy, Denmark, Sweden, Finland, Spain, Portugal, Poland, Greece, the Baltic countries, Czech Republic, Croatia, Slovenia, Slovakia, Hungary, Romania and Bulgaria as well as, Switzerland, Norway, the Balkans and Turkey. Countries beyond this geographic scope are modelled at an aggregate level.

A.4 Below we present both the general features of the power market model and the approaches used specifically for modelling of the WB6 power markets.

General features of FTI-CL Energy power market model

Price calculation

A.5 This model uses a detailed bottom-up methodology: the supply from flexible thermal power plants is modelled individually to meet the demand net of the supply of must-run renewable generators. The dispatch is determined to minimise the costs of generation in the considered geographical scope while satisfying the unit commitment constraints of generators as well as the flow constraints over the European transmission network. The model uses the zonal transmission network representation that matches with the price zones currently implemented in Europe and the commercial transmission boundaries.

A.6 The model calculates the price in each price zone as the marginal value of energy delivered in that zone based on the simulated bids of flexible generators. These bids closely follow the estimated short-run variable cost of power generation. Therefore, the estimated clearing prices correspond to the marginal cost of electricity. Such estimation of electricity prices based on the marginal cost is realistic as long as the capacity margin above the demand is high and there is high competition between generators to serve the demand.

Renewable generation

A.7 Given the impact of renewable generation variability on future power system, we have developed a specific methodology to represent wind and solar production:

- Wind production. Following extensive analysis for multiple clients on the impact of wind variability on future power system, we have developed a "hybrid" wind model combining historic wind speed data and historic wind power production. This combined methodology strengthens our wind modelling capability as it goes beyond wind turbine manufacturers' data and uses historic technical performances at the heart of our wind-speed-to-power converter algorithm.

- Solar production. As solar technical performances are continuously improved, we have modelled solar production with great details to include future technical improvements and technologies. Besides using historic solar production, we have developed a dedicated methodology to model the impact of future technical improvements, such as capturing non-direct solar irradiation.

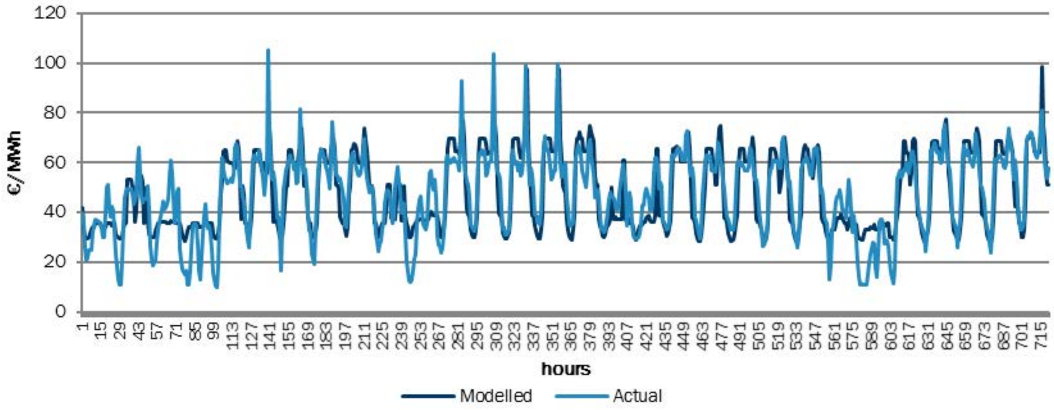
- Pumped Storage. Our model provides a specific add-on that optimises pumping and dispatch decisions on a weekly basis.

- On-site storage. Our model provides flexibility to model on-site storage impact on the power system. These additional features could be analysed in further sensitivities.

Back-casting calibration

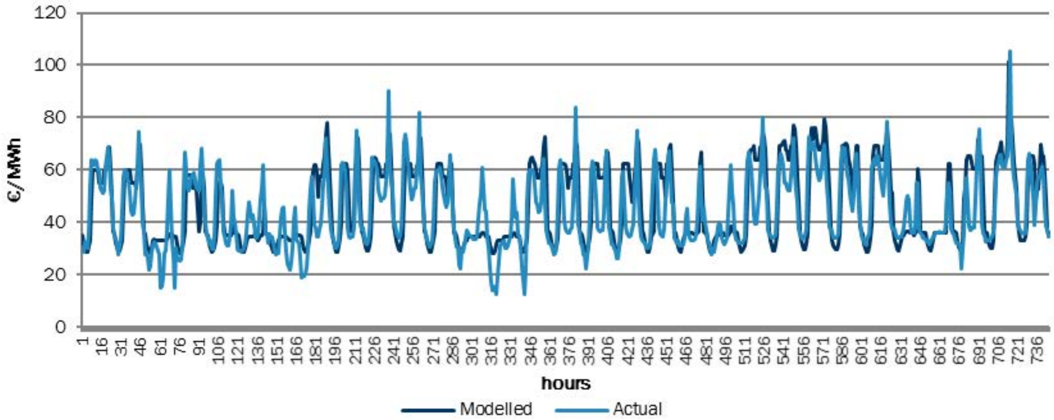
A.8 Our model has been calibrated with respect to the historical price profiles observed in a number of European countries. For example, Figure 21 and Figure 22 below show the results of the back-casting calibration of the prices calculated by the model against the realised prices in 2012 in France and Germany.

Figure 21: Back-casting calibration – FR hourly prices, November 2012



Source: *FTI-CL*

Figure 22: Back-casting calibration – DE hourly prices, October 2012



Source: *FTI-CL*

WB6 power market tailored modelling framework

Time horizon

A.9 The system adequacy in WB6 Contracting Parties is assessed from 2020 to 2030, using the FTI-CL Energy hourly power market model.

Geographic scope

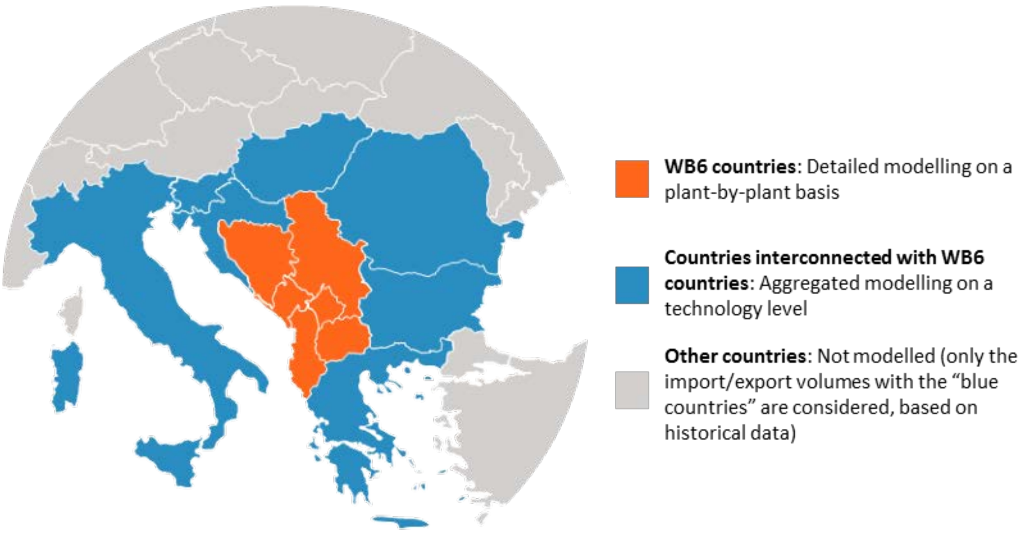
A.10 To account for the impact of neighbouring countries on WB6 power markets, the FTI-CL Energy hourly power market model is calibrated on an extended regional geographic scope including WB6 Contracting Parties and their first tier neighbouring (from a power market point of view) countries (Greece, Bulgaria, Romania, Hungary, Croatia, Slovenia and Italy[114]), as depicted in Figure 23.

A.11 To account for WB6 market specificities, a greater modelling granularity is used for WB6 Contracting Parties compared to their neighbouring countries:

- The WB6 region is modelled using a detailed plant-by-plant modelling (each power plant unit is modelled separately). Assumptions regarding generation capacity, demand and cross-border outlook are introduced and discussed in Appendix B.

- Countries interconnected with the WB6 region are modelled using an aggregated technology level modelling (power plants are aggregated by technology and age). Demand, generation capacity and cross-border capacity forecasts are based on the latest ENTSO-E forecasts (MAF 2018 for 2020 and 2025 and TYNDP Sustainable Transition scenario for 2030).

Figure 23: Geographic scope considered in our adequacy analysis



Source: FTI-CL

Multi-samples modelling framework

A.12 The multi-samples market model assumes that power markets operate under current market rules, are fully competitive and coupled (within WB6 Contracting Parties and with neighbouring countries) within the bounds of the future Net Transfer Capacities (NTC) based on TSOs forecasts presented in the following paragraphs.

114 A new transmission line is expected between Montenegro and Italia in 2020. Although Slovenia is not directly adjacent to the WB6 region, it is included in the modelling to link the Italian and Croatian power systems.

Fully competitive power market

A.13 Assuming fully competitive power markets under current market rules implies that (i) generation decisions are based on hourly merit-order dispatch based on marginal cost of production of the different power plants, (ii) power plant operators bid their short run marginal cost (SRMC) based on unsubsidised fuel price and unsubsidised variable operation and maintenance cost, and (iii) wholesale power price would be subject to current wholesale power price cap of 3000€/MWh.

- Subsidies on coal generation are frequent in the WB6 region[115]: they can translate into lignite prices or fixed maintenance and operation costs for coal-based electricity producers significantly lower than what they would bear in unsubsidised countries. As a result, subsidies allow coal electricity producers in the WB6 region to minimise their losses or even generate profits, which distorts competition with other countries and technologies. In this study, we remove subsidies by considering (i) market-based lignite prices, and (ii) typical fixed operation and maintenance costs (cf. B.8 and B.12).

Coupled power markets

A.14 Assuming wholesale power markets are coupled implies that day-ahead market prices are calculated by optimising all regional power markets simultaneously, and that cross-border flows between power markets are optimised to minimise the overall system cost, while accounting for the future Net Transfer Capacities (NTC) based on TSOs forecasts presented in the following paragraphs.

A.15 To reflect potential market-coupling inefficiencies, a sensitivity analysis in which several cross-border interconnections are constrained is also considered.

Multi-samples simulations

A.16 Forward looking probabilistic Monte-Carlo simulations are designed considering a sample approach based on three representative weather samples, as defined by ENTSO-E[116], and ten randomly drawn outage patterns for thermal plants based on forced outage rates provided by each TSO[117], totalling to 30 distinct samples.

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115 See Energy Community Secretariat, 2019, Rocking the Boat: What is Keeping the Energy Community's Coal Sector Afloat? Analysis of Direct and Selected Hidden Subsidies to Coal Electricity Production in the Energy Community Contracting Parties. Available at: https://www.energy-community.org/dam/jcr:23503de3-fccd-48f8-a469-c633e9ac5232/EnC%20Coal%20Study%20Report%20WEB.pdf

116 Cf. ENTSOE, 2018, TYNDP 2018 Data and expertise as key ingredients. Available at: https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/Technical/DataExpertise.pdf

117 Or, when unavailable, based on generic values used by ENTSO-E in the MAF.

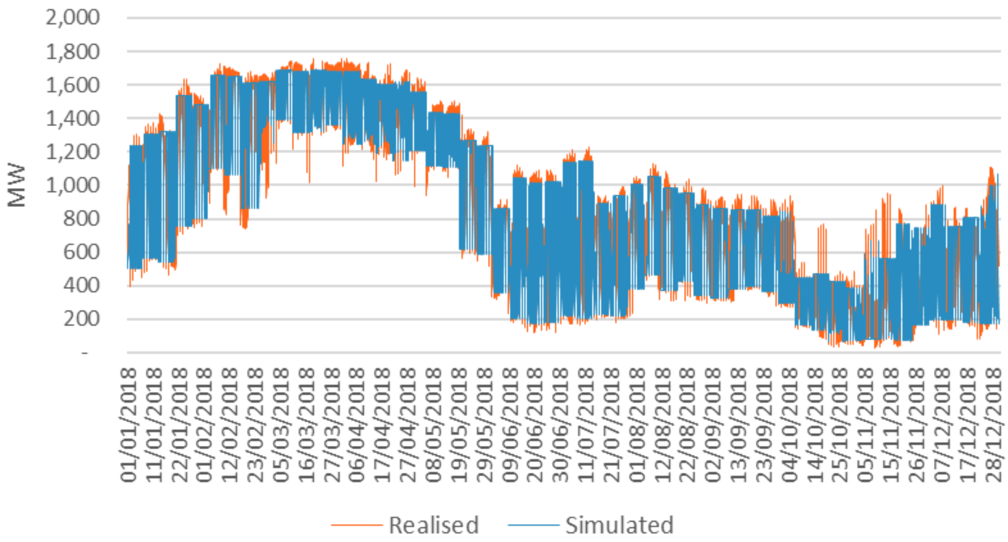
A.17 Representative weather samples, as defined by ENTSO-E, include wind and PV hourly capacity factor, hourly demand, and hydro availability:

- For wind and PV hourly capacity factors as well as hourly demand, ENTSO-E has built a climate database (PECD) to perform its TYNDP. Among 34 historical weather scenarios, three have been selected as the most representative years based on a K-clustering analysis by ENTSO-E: 1982, 1984 and 2007.

- For hydro, we use historical national hourly hydro generation data, either provided by WB6 TSOs or available on the ENTSO-E transparency platform, to define three years of hydro inflows. The 1984 weather sample, corresponding to an average hydro year, is based on 2016 data whereas the 1982 climatic year (dry year) is based on 2017 data and the 2007 climatic year (wet year) on 2018 data.

A.18 Furthermore, in addition to capturing the year-on-year hydro variability, the power market model is set up to model the hourly flexibility of hydro as shown on Figure 24 below, which compares the Albanian historical hourly hydro generation for 2018 and the one computed by our power model.

Figure 24: Simulated and realised hourly hydro generation for Albania in 2018



Source: FTI-CL based on OST data for historical data

Appendix B

Adequacy assessment background assumptions

Introduction

B.1 This appendix presents the approaches and assumptions used to assess adequacy in the WB6 power markets by Compass Lexecon.

B.2 Future WB6 power markets are mainly defined by the five-power market fundamental drivers being (i) power supply (e.g. generation capacity and demand side response), (ii) power demand (including reserves), (iii) cross-border interconnection capacity, (iv) commodities including gas, coal, oil, CO2 and (v) operating cost.

B.3 While (i) assumptions for commodities are based on the World Energy Outlook (WEO) 2018[118] published by the International Energy Agency (IEA) and on values provided by the Directorate-General for Energy (DG Ener) of the European Commission and (ii) assumptions for costs are based on a literature review, scenarios for the evolution of the first three market fundamentals (supply, demand and interconnection) are grounded on latest TSO's publications (mainly national network development plans, and generation adequacy studies when existing). Assumptions on the five drivers are introduced in the following paragraphs.

B.4 Below we present more specifically, the assumptions on future commodity prices, generators' costs and the elements of supply, demand and interconnection capacity projection.

Future commodity prices assumptions

B.5 Reference prices for gas, oil and CO2 are based on forward prices for the coming years and on the New Policies scenario of the WEO 2018 for 2025 and 2030.[119]

B.6 Oil and CO2 (in case of participation to the EU ETS market) prices applied to the WB6 region are assumed to be equal to these reference prices. In particular, the CO2 EU ETS price is estimated at 22€/tCO2 in 2020 increasing to 30€/tCO2 in 2030.

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118 OECD/IEA, 2018. World Energy Outlook 2018. https://webstore.iea.org/world-energy-outlook-2018

119 *Ibid.*

- To test the impact of potential transitional implementation of CO2 EU ETS in the WB6 between 2025 and 2030, a sensitivity analysis on the maximum CO2 price in WB6 Contracting Parties that existing lignite plants could face without endangering their future economics between 2025 and 2030 is also considered.

B.7 For gas prices, the reference price is used to determine CWE[120] hub prices. For WB6 Contracting Parties, we assume a regional gas price featuring a premium on top of the CWE hub prices. Assumed gas prices for the WB6 region are equal to 26€/MWh in 2020 and 27€/MWh in 2030.

B.8 Regarding lignite prices, the analysis uses a common regional coal price of 8.3€/MWh, based on DG Energy.[121] This value is higher than the current observed prices due to the importance of lignite subsidies in WB6 Contracting Parties, which we remove in this study.

Generators' costs assumptions

B.9 Several types of costs are considered in the analysis:

- The short-run marginal cost (SRMC) of power plants,
- Their fixed operation and maintenance (FOM) costs, and,
- Their investment and refurbishment costs.

B.10 Short-run marginal costs of thermal plants are computed as:

$$SRMC\left(\frac{€}{MWh}\right) = Variable\ Operation\ and\ Maintenance\ Costs\left(\frac{€}{MWh}\right) + \frac{Fuel\ price\left(\frac{€}{MWh}\right) + CO2\ price\left(\frac{€}{tCO2}\right) * Emission\ factor\left(\frac{tCO2}{MWh}\right)}{Efficiency\ (\%)}$$

B.11 Values for variable Operation and Maintenance costs, emission factor and efficiency have been provided by TSOs. When unavailable, generic values assumed by ENTSO-E for the MAF are used (cf. Table 6).

120 Central Western Europe.

121 Based on DG Energy assumption, as assumed by ENTSO-E in the EUCO scenario (cf. https://tyndp.entsoe.eu/Documents/TYNDP%20documents/TYNDP2018/consultation/Methodology/Scenario%20Report%20ANNEX%20II%20Methodology.pdf, p 5)

Table 6: Assumptions of variable O&M and efficiency for lignite plants

Plant	Variable O&M costs (€/MWh)	Efficiency (%)	Source
Banovici	3.3	36	ISO
Bitola 1,2 and 3	3.7	33	TSO
Bitola 4	4.6	44	TSO
Gacko 1	3.3	31	ISO
Kakanj 5	3.3	31	ISO
Kakanj 6	3.3	32	ISO
Kakanj 7	3.3	30	ISO
Kakanj 8	3.3	36	ISO
Kolubara A 1-3	3.3	28	FTI-CL based on ENTSOE data
Kolubara A5	3.3	36	FTI-CL based on ENTSOE data
Kosovo e RE	3.3	39	TSO
Kosovo A 3,4 and 5	3.4	23	TSO
Kosovo B 1 and 2	3.4	31	TSO
Kostolac A	3.3	31	FTI-CL based on ENTSOE data
Kostolac B 1 and 2	3.3	33	FTI-CL based on ENTSOE data
Kostolac B3	3.3	43	FTI-CL based on ENTSOE data
Morava 1	3.3	29	FTI-CL based on ENTSOE data
Negotino new plant	4.6	44	TSO
Nikola Tesla A 1-6	3.3	31	FTI-CL based on ENTSOE data
Nikola Tesla B 1 and 2	3.3	32	FTI-CL based on ENTSOE data
Oslomej 1	3.7	33	TSO
Oslomej new plant	4.6	44	TSO
Pljevlja 1	3.3	33	TSO
Pljevlja 2	3.3	38	FTI-CL based on ENTSOE data
Stanari	3.3	36	ISO
Tuzla 3	3.3	25	ISO
Tuzla 4 and 5	3.3	30	ISO
Tuzla 6	3.3	34	ISO
Tuzla 7	3.3	36	ISO
Ugljevik 1	3.3	31	ISO
Ugljevik 3	3.3	36	ISO

Notes: Source: FTI-CL, based on ENTSOE and TSO's inputs

B.12 FOM costs are also considered in the analysis. To remove the impact on current subsidies in WB6 Contracting Parties, we base FOM costs on values encountered in the literature. In particular, FOM costs of 40€/kW-year are assumed for all lignite plants in WB6 Contracting Parties.[122]

B.13 Finally, the analysis also considers long-term costs, both for investment in new technologies and refurbishment of existing plants to comply with LCPD by 2023 and BAT standards defined under the IED by 2028. These costs are described in Table 7, based on a WACC of 7%.[123]

Table 7: Investment and refurbishment annualised costs by technology

	Investment costs			Refurbishment costs		
Technology	**Amortization period (years)**	**Annualised costs for 2020 (€/kW)**	**Annualised costs for 2030 (€/kW)**	**Amortization period (years)**	**LCPD annualised cost (€/kW)**	**IED annualised cost (€/kW)**
Coal	35	115		10	15	30
CCGT	30	65		/	/	/
OCGT	25	45		/	/	/
Battery	10	140	80	/	/	/
Long term storage	20	125	80	/	/	/

Notes: *Refurbishment only applies to coal technology.*
Source: *FTI-CL based on ETRI, e3a Modelling, Eurelectric and Energy Community.*

Power market supply, demand and interconnection assumptions

B.14 Scenarios for the evolution of power supply, power demand and cross-border interconnection are based on latest TSO's publications (national network development plans, and generation adequacy studies when existing) completed with the Energy Community Secretariat assumption on Renewable Energy development by 2030.

Renewable (RES) capacity in 2030

B.15 Assumptions for 2030 RES capacity are based on the Energy Community Secretariat which assumes (for the purpose of the study) a 10% increase across all WB6 Contracting Party compared to 2020 targets. These percentages are then translated into percentages on electricity consumption and applied in each country (except Albania, whose RES penetration rate is already quite high) as presented in Table 8.

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122 Based on DECC, 2011, Electricity Generation Cost Model - 2011 Update Revision 1. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/65714/2127-electricity-generation-cost-model-2011.pdf

123 Assumption made by the Energy Community Secretariat in its study on coal subsidies.

Table 8: RES share assumption (% of power consumption)

	AL	BA	KO*	ME	MK	RS
2020	90.7%	59.6%	14.3%	26.8%	51.4%	36.6%
2025	90.7%	63.5%	15.7%	29.7%	55.3%	40.0%
2030	90.7%	67.4%	17.2%	32.6%	59.2%	43.4%

Notes: *2025 is an interpolation between 2020 and 2030*
Source: *FTI-CL based on data provided by Energy Community*

B.16 In addition to RES capacity outlook assumed in the TSO's publications, additional RES capacities are derived by increasing wind and solar installed capacity outlook to 2030.

B.17 The following paragraphs present in more details the future capacity and demand outlooks, main sources and assumptions for each WB6 Contracting Party.

Albania

B.18 Background assumptions are mainly based on data sent by OST, the Albanian TSO (no recent national transmission network development plan is publicly available at date of the report). Outlooks for generation capacity, demand, reserves and cross-border capacity are presented in the following paragraphs.

Generation capacity

B.19 Generation capacity outlook up to 2030 is based on information provided by OST. Except one 100-MW oil plant,[124] the Albanian power generation relies exclusively on hydro plants, as depicted on Figure 38. By 2030, almost 1 GW of new hydro plants is planned by the TSO (compared to the 2018 level): 450 MW are run-of-river and 550 MW are large dispatchable hydro. Given the current moratorium on future hydro power plants (due to environmental constraints),[125] as a conservative assumption, it has been agreed with the Energy Community Secretariat that only 50% of new run-of-river capacity should be considered in this study.

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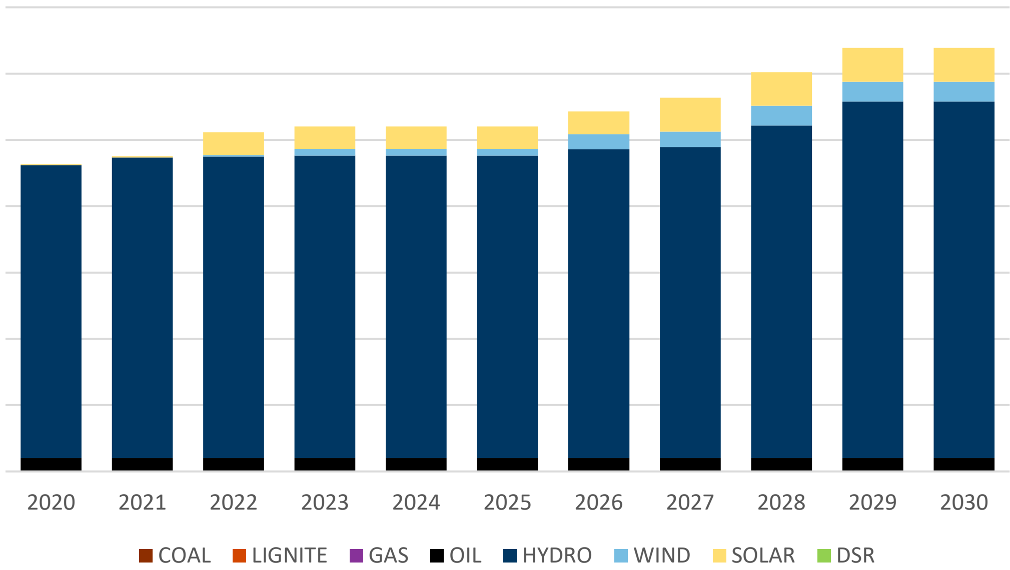
124 Due to several technical issues (combined with high generation costs), this plant has almost never produced so far. The matter has been subject to several arbitral proceedings with the constructor. The Ministry of Energy and Infrastructure has however launched a competitive procedure for the award of a 20-years concession contract, for the rehabilitation and gas conversion of the TEC Vlora, available at: http://openprocurement.al/sq/concession/view/id/20. However, this tender procedure has been suspended. Since there is no official decision yet on actual implementation of this potential conversion, and no concession/PPP has yet been awarded, in the study, we assume that the plant keeps burning oil fuel and is available for the period 2020-2030.

125 For instance, cf. https://www.reuters.com/article/us-albania-energy-hydropower/albania-rethinking-hydro-policy-on-environmental-concerns-idUSKCN1PI2R7. Actions have been taken by the Ministry of Energy and Infrastructure to verify compliance of concessionaires with their contract obligations and environmental compliance. This process has already resulted in termination of 27 existing HPPs'

Figure 25: Available capacity forecast by technology in Albania (MW)



Source: FTI-CL based on values provided by OST

Demand and reserves

B.20 Demand and reserves forecasts are described in Table 9, based on OST data.

Table 9: Demand and reserves outlooks for Albania

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Annual consumption (GWh)	7,520	7,701	7,878	8,059	8,237	8,418	8,595	8,775	8,951	9,130	9,312
Peak demand (MW)	1,522	1,546	1,574	1,605	1,639	1,674	1,709	1,745	1,783	1,822	1,862
Frequency reserves (MW)	144	145	146	146	147	148	149	150	151	152	153

Notes: The realistic scenario is considered for the demand forecast.
Source: FTI-CL based on values provided by OST

concession contracts after screening 80; as per official announcement available at https://www.infrastruktura.gov.al/perfundon-procesi-i-skanimit-bonati-nderpresim-27-kontrata-per-ndertimin-e-80-hec-eve/

Cross-border capacity outlook

B.21 Expected future NTCs have been provided by OST. The main evolution is a new line with North Macedonia expected to be commissioned in 2022.

B.22 Moreover, while the current technical transmission capacity between Albania and Kosovo* is already 600 MW since 2016, we understand that only 200 MW are effectively used due to the dispute between the Serbian and the Kosovar TSOs. In this study, we assume that this situation will be solved soon and the full NTC will be available for market players from 2021.

Table 10: Cross-border capacity outlook for Albania (NTC, in MW)

		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
AL-ME	AL➔ME	500	500	500	500	500	500	500	500	500	500	500
	ME➔AL	500	500	500	500	500	500	500	500	500	500	500
AL-MK	AL➔MK	0	0	500	500	500	500	500	500	500	500	500
	MK➔AL	0	0	500	500	500	500	500	500	500	500	500
AL-GR	AL➔GR	250	250	250	250	250	250	250	250	250	250	250
	GR➔AL	250	250	250	250	250	250	250	250	250	250	250
AL-KO*	AL➔KO*	200	600	600	600	600	600	600	600	600	600	600
	KO*➔AL	200	600	600	600	600	600	600	600	600	600	600

Source: FTI-CL based on values provided by OST

Bosnia and Herzegovina

B.23 Background assumptions for Bosnia and Herzegovina are based on the latest national network development plan for 2019-2028[126] and discussion with NOSBiH, the national Independent System Operator (ISO). Outlooks for generation capacity, demand, reserves and cross-border capacity are presented below.

Generation capacity

B.24 Generation capacity outlook is based on the latest national network development plan for 2019-2028. In this document, NOSBiH considers plants connected to the transmission grid only; decentralised capacity connected to the distribution grid are implicitly taken into account by reducing demand from the distribution grid.

B.25 Bosnia and Herzegovina mainly rely on hydro and lignite generation. In the next decade, 1.5 GW of lignite and 0.5 GW of CCGT are assumed to be commissioned. Moreover, Tuzla 3 and 4 units as well as Kakanj 5 unit have opted-out from the Large Combustion Plant Directive

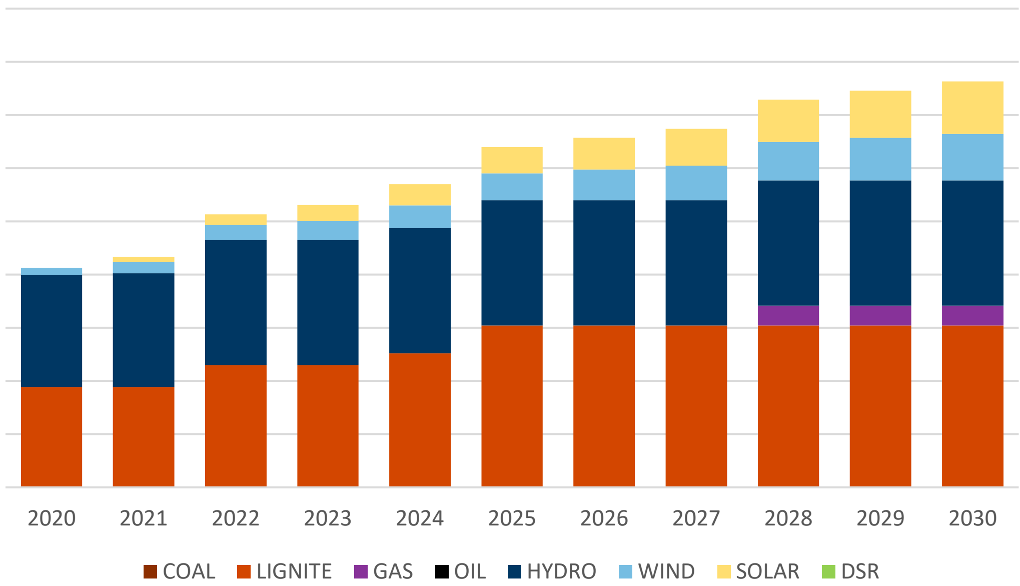
[126] NOSBiH, 2018, Indikativni plan razvoja proizvodnje 2019-2028, available at: https://www.nosbih.ba/files/dokumenti/Indikativan%20plan%20razvoja/2018/IPRP%202019-2028.pdf

(LCPD, 2001/80/EC).[127] As a result, they shall close no later than 31 December 2023 and shall not be operated more than 20,000 operating hours between 2018 and 2023.[128] No other thermal units are expected to close up to 2028. Installed hydro capacity is assumed to increase by 250 MW between 2020 and 2030.

B.26 Since this study assesses the capacity adequacy up to 2030, assumptions on the generation capacity outlook for 2028-2030 are necessary (since they are not provided by the national network development plan). We assume that thermal and hydro installed capacity is constant over this period (no new or closed units).

B.27 Moreover, due to increase of RES in 2030, 1.7 GW of additional wind and PV capacity are added to the ISO's forecast for 2030.

Figure 26: Available capacity forecast by technology in Bosnia and Herzegovina (MW)



Source: FTI-CL based on values provided by the Bosnian network development plan and values provided by NOSBiH

127 Cf. the summary report on the final list of opted-out plants available at: https://energy-community.org/dam/jcr:1adf04b4-fc82-4ece-a07b-693da6ce9175/ECS_ENV_opt-out%20list_042018.pdf

128 In the model, we assume that the 20,000 operating hours are evenly distributed between 2018 and 2023. As a result, the maximum yearly availability factor of each unit is 38% (20000/(2023-2018+1)/8760). In reality, from the reporting of 2018, we already can see preliminary indications that this is not the case and that plants are run at or close to full load. It is thus very likely that they will reach the 20,000 hours limit already in 2020 or 2021.

Demand and reserves

B.28 Demand and reserves forecasts are presented in Table 11. Annual consumption forecast is based on the 2019-2028 network development plan whereas forecast reserves rely on ENTSO-E's assumptions.

Table 11: Demand and reserves outlooks for Bosnia and Herzegovina

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual consumption (TWh)	12.9	13.0	13.2	13.3	13.5	13.7	13.8	13.9	14.1	14.3	14.4
Peak demand (MW)	2,229	2,249	2,269	2,289	2,310	2,331	2,352	2,373	2,394	2,414	2,435
Frequency reserves (MW)	282	282	282	282	282	282	282	282	282	282	282

Notes: *The reference scenario is considered for the demand forecast. As the national transmission development plant is studied up to 2028 only, we assume the same demand increase for 2029 and 2030 as in the previous years.*
Reserves values are based on assumptions made by ENTSO-E in its MAF 2018 and are assumed to stay constant up to 2030.

Source: *FTI-CL based on NOSBiH for peak demand and annual consumption and on ENTSO-E for reserves.*

Cross-border capacity

B.29 Interconnection capacity forecasts have been provided directly by the Bosnian ISO, who expects significant NTC increases with Croatia in 2028, with Montenegro in 2025/2026 and with Serbia in 2026.

Table 12: Cross-border capacity outlook for Bosnia and Herzegovina (NTC, in MW)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BA-HR	BA→HR	700	700	700	700	700	700	700	700	1300	1300	1300
	HR→BA	700	700	700	700	700	700	700	700	1300	1300	1300
BA-ME	BA→ME	550	550	550	550	550	800	950	950	950	950	950
	ME→BA	550	550	550	550	550	700	900	900	900	900	900
BA-RS	BA→RS	550	550	550	550	550	550	1050	1050	1050	1050	1050
	RS→BA	550	550	550	550	550	550	1150	1150	1150	1150	1150

Source: *FTI-CL based on values provided by NOSBiH.*

Kosovo*

B.30 Main assumptions are based on the baseline scenario of the latest national network development plan for 2018-2027,[129] the adequacy study for 2019-2028[130] and discussion with KOSTT, the Kosovar TSO.

Generation capacity

B.31 Generation capacity outlook is based on the baseline scenario of the latest adequacy study for 2019-2028. Electricity is generated quasi-exclusively by lignite plants and it is expected to remain true in the next decade. In 2023, the Kosovo A plant[131] will be decommissioned and a new lignite unit (Kosova e RE – 450 MW) will become operational. A new pumped hydro storage facility is also expected in 2023 to provide ancillary services.

B.32 Regarding RES capacity, 80 MW of wind and PV capacity are added to the TSO's forecast to account for increase or RES capacity by 2030.

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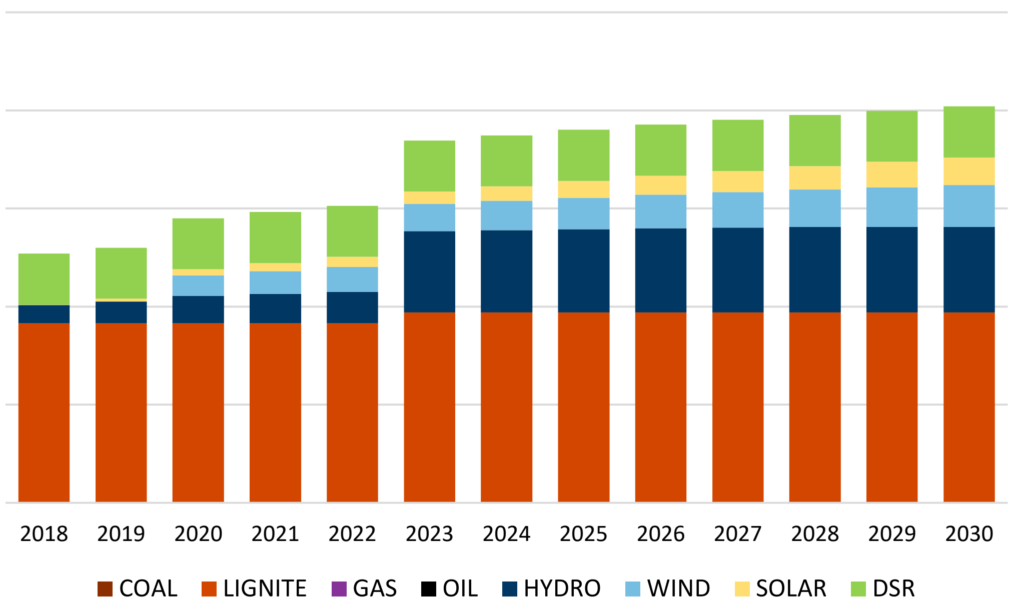
129 KOSTT, 2018, Transmission development plan 2018-2027. Available in English at: http://www.kostt.com/website/images/stories/dokumente/tjera/planizhvillimor/Transmission_Development_Plan_2018-2027.pdf

130 KOSTT, 2019, Plani i adekuacisë së gjenerimit 2019-2028. Available in Albanian at: http://www.kostt.com/website/images/stories/dokumente/tjera/Plani_i_Adekuacise_se_Gjenerimit_2019-2028.pdf

131 While its installed capacity is 800MW, Kosovo A cannot produce more than 400MW (units A1 and A2 have been out of operation for several years and other units cannot operate to their full capacity).

Figure 27: Available capacity forecast by technology in Kosovo* (MW)



Notes: *DSR capacity is considered to reflect possible load curtailment due to lack of tertiary reserves (cf. para B.32)*

Source: *FTI-CL based on values provided by the Kosovar network development plan and values provided by KOSTT*

Demand and reserves

B.33 Demand and reserves forecasts are presented in Table 13.

Table 13: Demand and reserves outlooks for Kosovo*

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual consumption (GWh)	5,721	5,777	5,822	5,851	5,894	5,919	5,945	5,995	6,007	6,057	6,092
Peak demand (MW)	1,210	1,221	1,231	1,237	1,246	1,251	1,257	1,267	1,270	1,280	1,288
Frequency reserves (MW)	299	299	300	491	490	490	493	494	494	494	494

Notes: *The base case scenario is considered for the demand forecast. As KOSTT studies the adequacy up to 2028 only, we assume the same demand increase for 2029 and 2030 as in the previous years. Reserves values are based on the base case scenario. The same values as in 2028 are considered in 2029 and 2030.*

Source: *FTI-CL based on KOSTT*

B.34 As mentioned in the adequacy study for the Kosovar power system, Kosovo currently has no generating unit that can provide tertiary reserves. As a result, current needs for tertiary reserve (260 MW) are not satisfied and in case a lignite plant fails, load curtailment is needed. For this reason, 260 MW of demand side response (DSR) are modelled in this study to meet the reserve demand.

B.35 After the construction of Kosova e Re, tertiary reserves will increase to 450 MW. Investment in a flexible unit (more specifically in a 200 MW pumped hydro storage) is suggested by the TSO as soon as 2023. In this study, a constant level of reserves, equal to 300 MW, is assumed throughout horizon and the new pumped hydro storage plant is not modelled on the supply side as it would not have a direct impact on the wholesale market.

Cross-border capacity

B.36 Interconnection capacity forecasts have been provided by KOSTT. Except for the line with Albania, NTCs are expected to stay constant during the time horizon of the study. While the current technical transmission capacity between Albania and Kosovo* is already 600 MW since 2016, we understand that only 200 MW are effectively used due to the dispute between the Serbian and the Kosovar TSOs. In this study, we assume that this situation will be solved soon and the full NTC will be available for market players from 2021.

Table 14: Cross-border capacity outlook for Kosovo* (NTC, in MW)

		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
KO*-AL	KO*➔AL	200	600	600	600	600	600	600	600	600	600	600
	AL➔KO*	200	600	600	600	600	600	600	600	600	600	600
KO*-ME	KO*➔ME	400	400	400	400	400	400	400	400	400	400	400
	ME➔KO*	400	400	400	400	400	400	400	400	400	400	400
KO*-MK	KO*➔MK	400	400	400	400	400	400	400	400	400	400	400
	MK➔KO*	400	400	400	400	400	400	400	400	400	400	400
KO*-RS	KO*➔RS	600	600	600	600	600	600	600	600	600	600	600
	RS➔KO*	600	600	600	600	600	600	600	600	600	600	600

Source: FTI-CL based on KOSTT

Montenegro

B.37 Main assumptions for Montenegro are based on the national network development plan for 2019-2028,[132][133] discussions with the TSO, CGES, as well as additional data sent by CGES.

Generation capacity

B.38 In the national network development plan for 2019-2028, the existing Pljevlja lignite plant is expected to be decommissioned in 2023, as it has decided to opt-out from the LCPD,[134] whereas a new lignite unit will become operational in 2020 (Pljevlja II). However, recent announcements from the Government seem to challenge these decisions.[135] In particular, the cooperation with Skoda Praha for the construction of the new plant has been terminated recently. Instead, it seems that the government decides to reconstruct the existing Pljevlja plant by 2021 to comply with emissions standard. Our discussion with CGES has confirmed that the project for a new power plant is currently cancelled as far as they know. As a result, in this study, we assume the refurbishment of the existing plant in order to meet environmental criteria and we do not consider the construction of the new plant.

B.39 Moreover, based on inputs from the TSO, about 500MW of large hydro are expected to be commissioned by 2030.[136]

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132 CGES, 2018, Plan razvoja prenosne mreže Crne Gore 2019-2028. Available in Montenegrin at: http://regagen.co.me/cms/public/image/uploads/Javni_poziv_sa_Nacrtom_plana_prenosne_mreze_i_planom_investicija.pdf

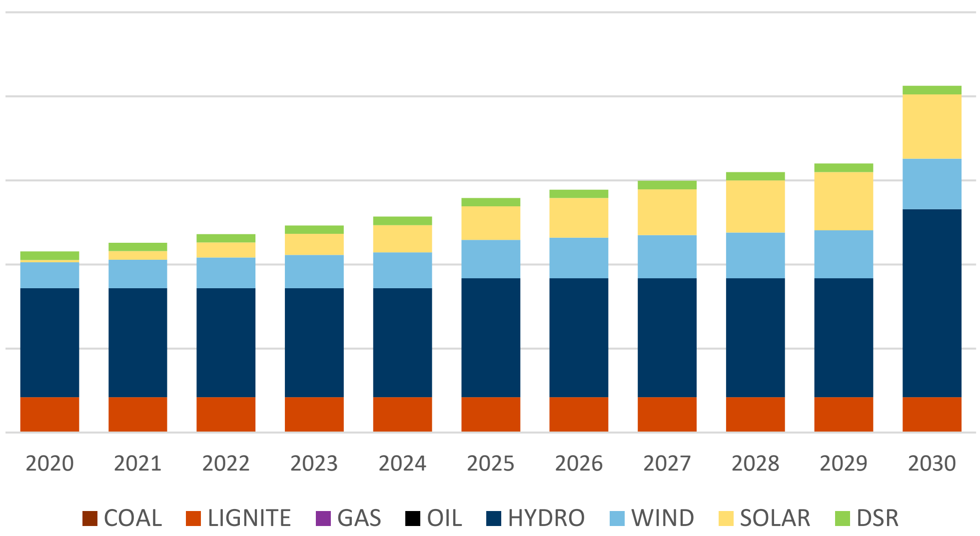
133 The network development plan for 2020-2029 was recently released (http://regagen.co.me/cms/public/image/uploads/2019.05.09_Poziv_na_javnu_raspravu_-_Plan_razvoja_prenosnog_sistema_el._en._sa_planom_investicija.pdf). Outlooks are closed to those assumed in this study.

134 TPP Pljevlja already used more than 7,000 operational hours in 2018. If this trend continues, the plant will reach the 20,000 limit earlier than 2023. In the modelling, we assume an even distribution of operating hours between 2018 and 2023 (3,300 operating hours per year).

135 Cf. http://www.gov.me/en/News/180095/Cooperation-with-Czech-Skoda-Praha-on-construction-of-Block-II-of-TPP-Pljevlja-terminated.html

136 Given the growing public opposition in Montenegro, future large hydro plants may be delayed or cancelled. In our study, we keep the assumptions made by the TSO. However, amending this assumption should have limited impact since the capacity increase occurs mainly in 2030.

Figure 28: Available capacity forecast by technology in Montenegro (MW)



Notes: *50 MW-DSR capacity is considered to reflect the current provision of frequency reserves by load (cf. para B.38)*

Source: *FTI-CL based on values provided by CGES.*

Demand and reserves

B.40 Demand and reserves forecasts are presented in Table 15. Demand forecast has been provided by CGES and is aligned with the latest national development plan for 2020-2029. Outlook for reserves has also been sent by CGES. Moreover, 50 MW of the reserve requirement is assumed to be provided by load:[137] that is why 50 MW of demand-side response are considered for Montenegro.

Table 15: Demand and reserves outlooks for Montenegro

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual consumption (GWh)	3,918	4,177	4,249	4,322	4,395	4,468	4,541	4,614	4,686	4,726	4,817
Peak demand (MW)	730	754	765	795	802	810	818	828	836	844	853
Frequency reserves (MW)	131	131	131	131	131	131	131	131	131	131	131

Notes: *Future annual consumption has been provided by CGES for 2018, 2021, 2028 and 2029. Linear interpolation has been applied to determine values for remaining years.*
Reserves values are based on the base case scenario. The same values as in 2028 are considered in 2029 and 2030.

Source: *FTI-CL based on values provided by CGES.*

137 Cf. the volumes of contracted balancing reserves on the ENTSO-E transparency platform.

Cross-border capacity

B.41 Based on inputs from the TSO, cross-border development involves:

- A new transmission line between Italy and Montenegro: a first pole line (600MW) will be in operation in 2020 and a second one (400MW) in 2025;
- A new line with Serbia, expected in 2024 (400 MW).

B.42 Contrary to the Bosnian ISO, the Montenegrin TSO does not expect any NTC increase for the ME-BA line. In the study, we consider the evolution expected by the Bosnian ISO since it seems more aligned with ENTSO-E's forecast in the latest MAF.[138]

Table 16: Cross-border capacity outlook for Montenegro (NTC, in MW)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ME-IT	ME→IT	600	600	600	600	600	1,000	1,000	1,000	1,000	1,000	1,000
	IT→ME	600	600	600	600	600	1,000	1,000	1,000	1,000	1,000	1,000
ME-AL	ME→AL	500	500	500	500	500	500	500	500	500	500	500
	AL→ME	500	500	500	500	500	500	500	500	500	500	500
ME-KO*[139]	ME→KO*	400	400	400	400	400	400	400	400	400	400	400
	KO*→ME	400	400	400	400	400	400	400	400	400	400	400
ME-RS	ME→RS	300	300	300	300	700	700	700	700	700	700	700
	RS→ME	300	300	300	300	700	700	700	700	700	700	700
ME-BA	ME→BA	550	550	550	550	550	700	900	900	900	900	900
	BA→ME	550	550	550	550	550	800	950	950	950	950	950

Source: FTI-CL based on values provided by NOSBiH (for the ME-BA line), KOSTT (for the ME-KO line) and CGES (for ME-IT and ME-RS lines).*

North Macedonia

B.43 Background assumptions are based on:

- the business-as-usual scenario of the national network development plan for 2020-2040;[140]

138 ENTSO-E assumes an NTC equal to 800 MW, like the Bosnian ISO, in 2025.

139 The TSO from Montenegro assumes an NTC equal to 450 MW with Kosovo* whereas the Kosovar TSO assumes an NTC of 400 MW. The most conservative value is assumed in the study.

140 MEPSO, 2017, Стратешки план за електропреносен систем период 2020-2040. Available in Macedonian at: http://www.mepso.com.mk/CMS99/Content_Data/Dokumenti/%D0%9F%D1%80%D0%BE%D0%B5%

- the business-as-usual scenario of the 2020-2040 adequacy study;[141]

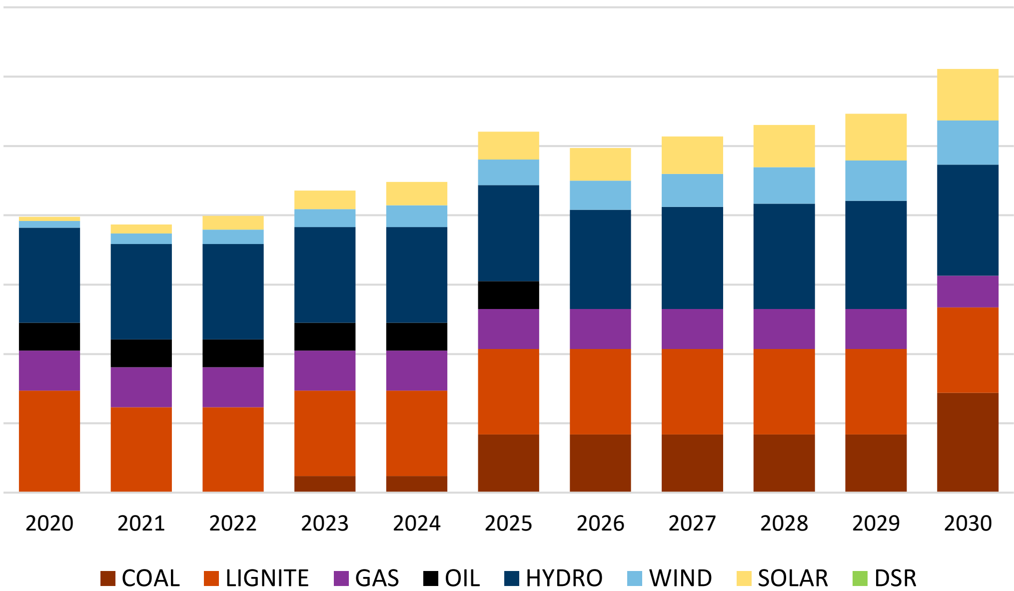
- Discussions and updated values sent by MEPSO, the Macedonian TSO.

Generation capacity

B.44 The Macedonian capacity mix includes lignite, gas and hydro plants. By 2030, about 100MW of small hydro are expected to be commissioned as well as about 700MW of coal plants. In the meantime, two units are assumed to be decommissioned (Oslomej 1 in 2020 and Negotino 1 in 2025).

B.45 Moreover, about 500 MW of additional wind and PV capacity are added to the TSO's to account for increase or RES capacity by 2030.

Figure 29: Available capacity forecast by technology in North Macedonia (MW)



Source: FTI-CL based on MEPSO data.

D0%BA%D1%82%D0%B8/Strateski%20plan%20na%20elektroprenosen%20sistem%202020-2040_10.11.2017_final.pdf

141 MEPSO, 2016, Студија за прогноза на биланс на ее и моќност за долгорочен период и анализа за адекватност на преносната мрежа на република македонија. Available in Macedonian at: http://www.mepso.com.mk/CMS99/Content_Data/Dokumenti/%D0%9F%D1%83%D0%B1%D0%BB%D0%B8%D0%BA%D0%B0%D1%86%D0%B8%D0%B8/77-2015%20-%20FINAL-MK%20-%2021-12-2016.pdf

Demand and reserves

B.46 Demand and reserves forecasts are presented in Table 17. They are based on updated data sent by MEPSO.

Table 17: Demand and reserves outlooks for North Macedonia

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual consumption (GWh)	7,150	7,296	7,442	7,588	7,734	7,880	8,170	8,460	8,750	9,040	9,330
Peak demand (MW)	1,476	1,520	1,564	1,609	1,653	1,697	1,717	1,737	1,756	1,776	1,796
Frequency reserves (MW)	168	168	168	168	168	168	168	168	168	168	168

Notes: *Future demand has been provided by MEPSO for 2018, 2020, 2025 and 2030. Linear interpolation has been applied to determine values for remaining years.*
Future reserve volume has been provided by MEPSO for 2018, 2025 and 2030 and is assumed to stay constant.

Source: *FTI-CL based on MEPSO data.*

Cross-border capacity

B.47 Future transmission capacity is based on data sent by the Macedonian TSO. Whereas MEPSO expects the new line with Albania to be operational from 2020 onwards, the Albanian TSO assumes a commissioning date in 2022. We use a conservative approach in our study and retain the latest date.

B.48 Moreover, the Macedonian TSO provides future NTCs for Serbia and Kosovo* combined. As future NTCs for the North Macedonia-Kosovo* line have already been provided by the Kosovar TSO, we are able to assess the evolution of the NTC of the North Macedonia-Serbia line as the difference between both previously mentioned values.

Table 18: Cross-border capacity outlook for North Macedonia (NTC, in MW)

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
MK-AL	MK→AL	0	0	500	500	500	500	500	500	500	500	500
	AL→MK	0	0	500	500	500	500	500	500	500	500	500
MK-GR	MK→GR	850	850	850	850	850	850	850	850	850	850	850
	GR→MK	850	850	850	850	850	850	850	850	850	850	850
MK-BG	MK→BG	350	350	350	400	400	400	400	400	400	400	400
	BG→MK	400	400	400	500	500	500	500	500	500	500	500
MK-RS	MK→RS	0	0	0	0	0	0	0	0	0	0	0
	RS→MK	250	250	250	250	250	250	250	250	250	250	250
MK-KO*	MK→KO*	400	400	400	400	400	400	400	400	400	400	400
	KO*→MK	400	400	400	400	400	400	400	400	400	400	400

Notes: *For the MK-AL line, we use the commissioning date assumed by the Albanian TSO.*
NTCs for MK-KO line are based on values provided by the Kosovar TSO. Values for the MK-RS line are computed as the difference between, on the one hand, NTCs for MK-{RS+KO*} provided by MEPSO and, on the other hand, NTCs for MK-KO* provided by KOSTT.*

Source: *FTI-CL based on: for MK-GR, MK-BG: MEPSO; for MK-KO*: KOSTT; for MK-AL: OST; for MK-RS: MEPSO and KOSTT.*

Serbia

B.49 Main assumptions are based on the realistic scenario developed in the national network development plan for 2018-2027[142] as well as the draft version of the national network development plan for 2019-2028.[143]

Generation capacity

B.50 Generation capacity outlook is based on the realistic scenario developed by EMS in the national development plan. Installed capacity is dominated by lignite and hydro plants. During the next 10 years, almost 500 MW of lignite and gas plants are assumed to be commissioned whereas hydro capacity remains relatively stable. In the meantime, about 300MW of lignite plants will close by 2023 since they are in the opt-out list of the LCPD (Kolubara A and Morava units).

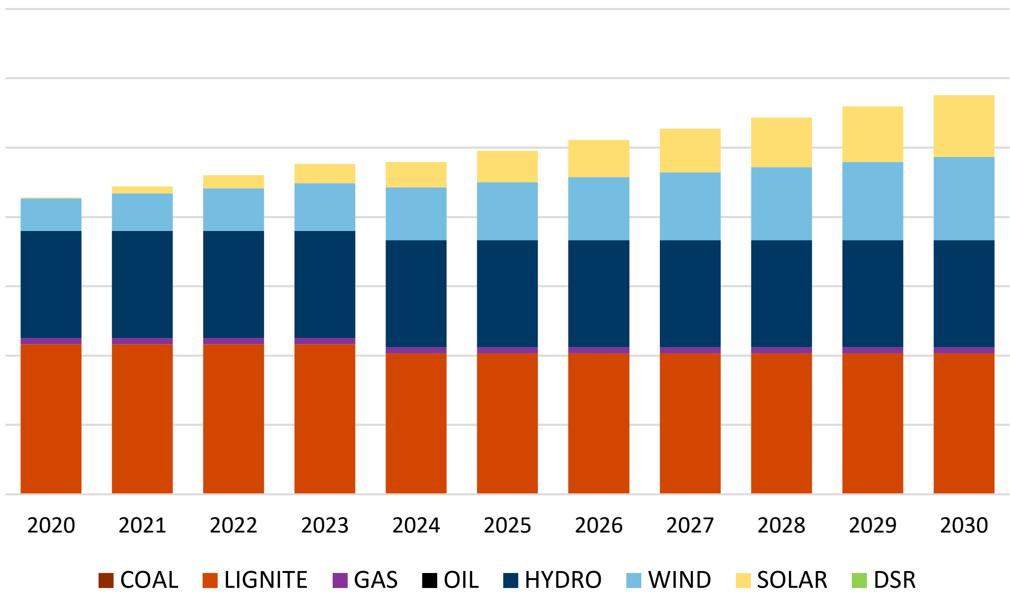
B.51 Since this study assesses the capacity adequacy up to 2030, assumptions on the generation capacity outlook for 2028-2030 are necessary (since they are not provided by the national network development plan). We assume that thermal and hydro installed capacity are constant over this period (no new or closed units).

142 EMS, 2018, План развоја преносног система републике србије за период 2018-2027. Available in Serbian at: https://ems.rs/media/uploads/plan-razvoja/Plan-razvoja-prenosnog-sistema-Republike-Srbije-2018-2027.pdf

143 EMS, 2019, План развоја преносног система републике србије за период 2019-2028. Available in Serbian at: https://www.aers.rs/FILES/JavnaKonsultacija/2019-02-13_Plan%20razvoja%20prenosnog%20sistema%20Republike%20Srbije%202019-2028.pdf

B.52 Finally, about 2.8 GW of additional wind and PV capacity are added to EMS's forecast to account for increase or RES capacity by 2030.

Figure 30: Available capacity forecast by technology in Serbia (MW)



Source: FTI-CL based on the Serbian network development plant

Demand and reserves

B.53 Demand and reserves forecasts are presented in Table 19 based on EMS's assumptions in its latest network development plan.

Table 19: Demand and reserves outlooks for Serbia

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Annual consumption (TWh)	36.1	36.4	36.7	37.1	37.3	37.7	38.1	38.4	38.5	39.0	39.2
Peak demand (MW)	6,312	6,346	6,377	6,408	6,439	6,468	6,497	6,525	6,558	6,588	6,618
Frequency reserves (MW)	460	460	460	460	460	460	460	460	460	460	460

Notes: Peak demand and volume of reserves are defined up to 2027. The same trend as in the previous years is assumed for 2028-2030.
Source: FTI-CL based on the latest Serbian network development plan.

Cross-border capacity

B.54 Limited information is available for cross-border capacity outlook in the Serbian transmission network development plan. The following capacity increases are considered by EMS:

- A new line with Montenegro in 2024, consistent with the view of the Montenegrin TSO, and;

- A new line with Bosnia and Herzegovina in 2024, whereas the Bosnian TSO expects this new line in 2026: in this study, we retain a conservative approach and the assumption made by the Bosnian TSO.

B.55 The remaining cross-border interconnections are assumed constant over 2020-2028. We assume that no capacity increase will take place between 2028 and 2030.

B.56 However, the Serbian transmission network development plan does not provide the values of future NTCs on a country-basis. That is why forecasts of NTCs are based on values mentioned by adjacent countries (for Bosnia and Herzegovina, Montenegro, Kosovo* and North Macedonia) or values assumed by ENTSO-E in the MAF 18 AND TYNDP 18 (for Croatia, Hungary, Romania[144] and Bulgaria).

Table 20: Cross-border capacity outlook for Serbia (NTC, in MW)

		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
BA-RS	BA➔RS	550	550	550	550	550	550	1,050	1,050	1,050	1,050	1,050
	RS➔BA	550	550	550	550	550	550	1,150	1,150	1,150	1,150	1,150
MK-RS	MK➔RS	0	0	0	0	0	0	0	0	0	0	0
	RS➔MK	250	250	250	250	250	250	250	250	250	250	250
ME-RS	ME➔RS	300	300	300	300	700	700	700	700	700	700	700
	RS➔ME	300	300	300	300	700	700	700	700	700	700	700
KO*-RS	KO*➔RS	600	600	600	600	600	600	600	600	600	600	600
	RS➔KO*	600	600	600	600	600	600	600	600	600	600	600
RS-BG	RS➔BG	200	200	200	200	200	200	200	200	200	200	200
	BG➔RS	500	500	500	500	500	500	500	350	350	350	350
RS-HR	RS➔HR	600	600	600	600	600	600	600	600	600	600	600
	HR➔RS	600	600	600	600	600	600	600	600	600	600	600
RS-HU	RS➔HU	600	600	600	600	600	600	600	600	600	600	600
	HU➔RS	600	600	600	600	600	600	600	600	600	600	600
RS-RO	RS➔RO	800	800	800	800	800	800	800	800	800	800	800
	RO➔RS	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000

Source: FTI-CL based on: for RS-BG, RS-HR, RS-HU and RS-RO lines: ENTSO-E and EMS; For BA-RS: NOSBiH; for MK-RS: MEPSO; for KO-RS: KOSTT; for ME-RS: CGES.*

144 In the TYNDP, the capacity between Serbia and Romania is expected to increase between 2020 and 2027. However, the Serbian TSO does not expect any increase between 2020 and 2028. Then, we assume a constant capacity up to 2030.

Summary on assumptions on the evolution of thermal capacity in WB6 Contracting Parties

B.57 The following tables sum up the assumptions taken by the TSOs regarding investments and decommissions of thermal plants in the WB6 region. These assumptions are considered as an input in the Base Case Scenario.

Table 21: List of new thermal plants

Unit	Country	Technology	Net capacity (MW)	Operation start year
Banovici 1	BA	Lignite	320	2024
Kakanj 8	BA	Lignite	270	2024
TE-TO Zenica	BA	Gas	372	2028
Tuzla 7	BA	Lignite	410	2022
Ugljevik-3	BA	Lignite	528	2025
Kosova e RE 1	KO*	Lignite	450	2023
Pljevlja 1[145]	ME	Lignite	205	2024
Bitola 4	MK	Coal	300	2030
Negotino	MK	Coal	300	2025
Oslomej	MK	Coal	120	2023
Pancevo	RS	Gas	180	2020
Kostolac-B 3	RS	Lignite	320	2020

Source: FTI-CL based on several WB6 TSOs' studies

145 In the case of the Pljevlja plant, the base case scenario considers its refurbishment by 2023 so that the plant can continue producing after the LCPD opt-out deadline.

Table 22: List of decommissioned thermal plants

Unit	Country	Technology	Net capacity (MW)	Operation end year
Kakanj 5	BA	Lignite	100	2023
Tuzla 3	BA	Lignite	90	2023
Tuzla 4	BA	Lignite	180	2023
Kosovo-A 3, 4, 5	KO*	Lignite	395	2022
Negotino 1	MK	Oil	200	2025
Oslomej 1	MK	Lignite	120	2020
Kolubara-A 1, 2, 3	RS	Lignite	70	2023
Morava 1	RS	Lignite	108	2023
Kolubara-A 5	RS	Lignite	100	2023

Source: FTI-CL based on several WB6 TSOs' studies

Appendix C

Detailed results of the adequacy assessment

Introduction

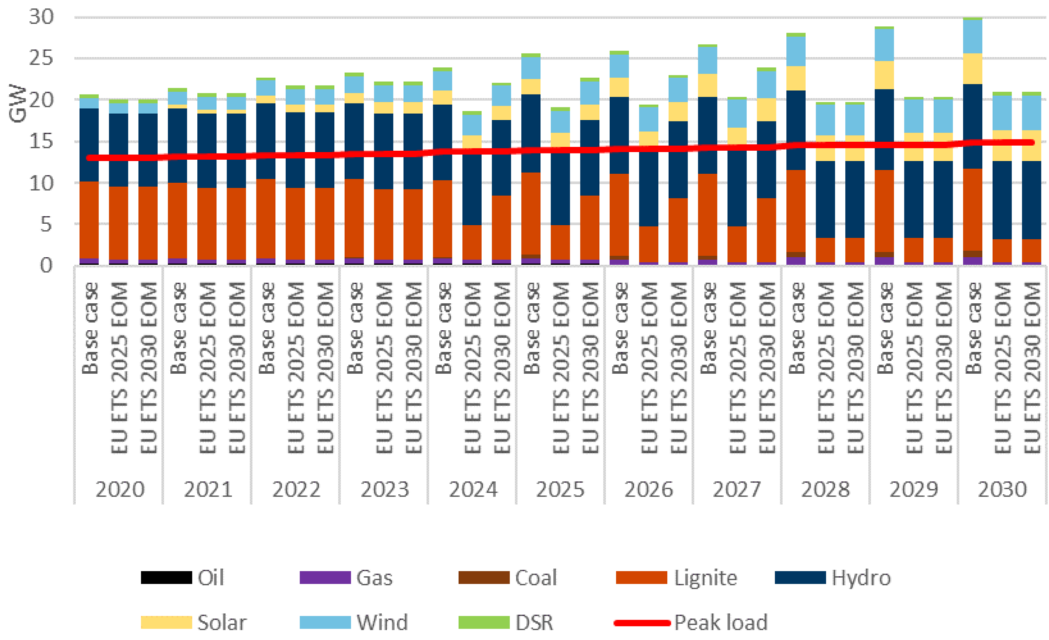
C.1 This appendix written by Compass Lexecon presents further details of the power market modelling outcomes to complement Section 4. In particular, this appendix presents:

- Capacity and generation outlooks provided by the power market model for WB6 Contracting Parties;
- Country-by-country details of the results of the adequacy analysis.

Power market model – WB6 capacity and generation outlooks

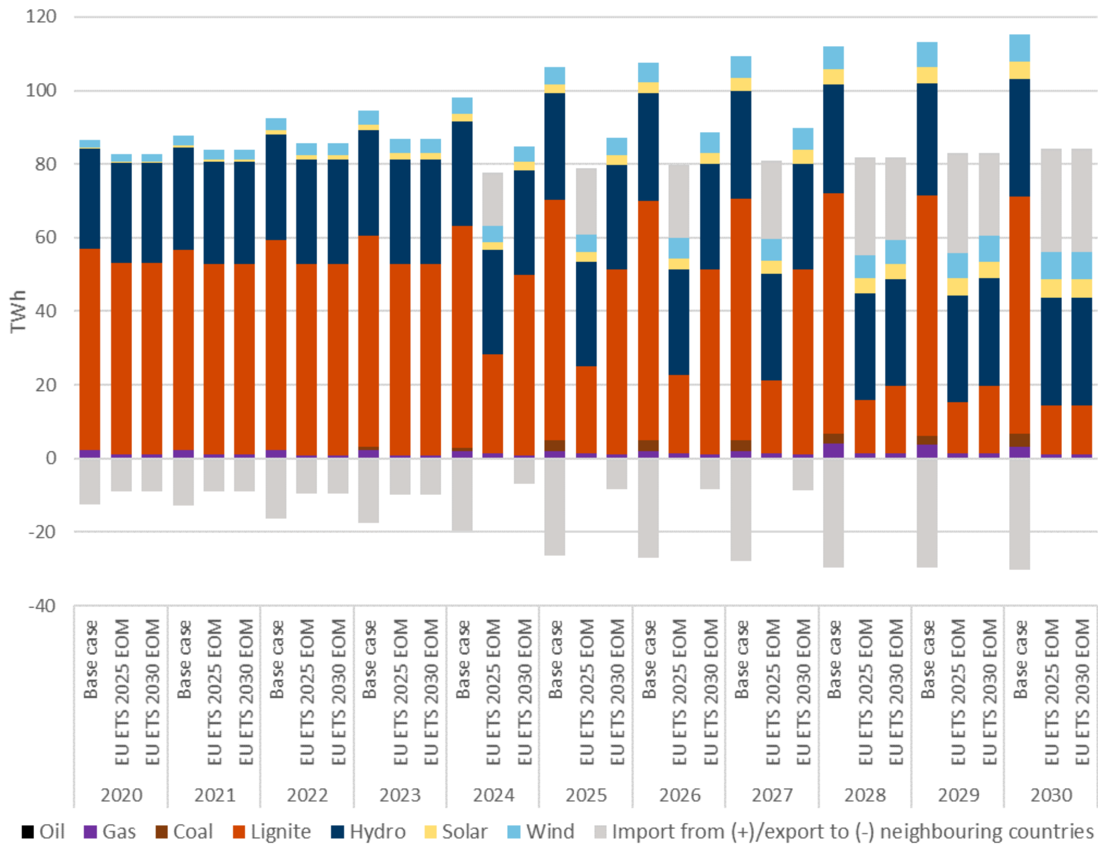
C.2 In this sub-section, WB6 modelled capacity and generation outlooks by technology are presented and compared between each scenario. Figure 31 shows the total capacity by technology for the whole WB6 region for the three studied scenarios while Figure 32 depicts the generation outlook (results on a country level are described in the next section) .

Figure 31: Installed capacity outlook in the WB6 region, per technology and per scenario (GW)



Source: *FTI-CL*

Figure 32: Generation outlook in the WB6 region, per technology and per scenario (TWh)



Source: *FTI-CL*

C.3 On the capacity outlook chart, the main difference between the three scenarios lies in the installed capacity of lignite plants (in orange) and, to a lower extent, of coal plants (in brown) and gas plants (in purple).

C.4 Regarding lignite plants, the introduction of a CO2 prices results in cancelled new projects as well as decommissioned plants in both EU ETS Energy Only scenarios compared to the base case scenario. Lignite power plants closures occur in late 2023 and late 2027, since plants cannot comply with environmental norms. Moreover, closures due to LCPD happen in the EU ETS 2025 scenario only. In the EU ETS 2030 scenario, the absence of CO2 pricing between 2025 and 2029 enables power plants to invest in LCPD refurbishment. However, in both scenarios, IED refurbishment is not economic, which explains why installed lignite capacity is the same from 2028 onwards, regardless of the EU ETS scenario.

C.5 The situation is similar for new coal projects (there are not existing coal plants as of 2018 in WB6 Contracting Parties): the introduction of a CO2 price would result in net profit level below annualised CAPEX for new investments. New projects for Bitola, Negotino and Oslomej are then cancelled in both EU ETS scenarios. Finally, for gas units, like for coal and lignite plants, new projects will not cover their investment CAPEX if a CO2 price is introduced. However, and contrary to existing lignite plants, existing gas plants (in particular the 255 MW TE-TO Skopje unit) are profitable enough to stay operational in both EU ETS Energy Only scenarios (in particular since no LCPD or IED refurbishment CAPEX are assumed for this technology).

C.6 It should be noted that this chart does not draw any conclusion on the ability of the power system to cover all demand. Indeed, this chart illustrates the installed capacity and not the capacity available to produce: because of outages for thermal plants or because of the unavailability of the primary resource (wind, sun or water), for renewable capacity, there is no guarantee that all installed capacity is available to meet demand. Comparison of the installed capacity and peak demand will be the focus of the section on adequacy assessment.

C.7 When studying generation, the main differences between the three scenarios lie in (i) the volume of import/export (in grey), and (ii) the generation of lignite plants (in orange).

C.8 In the Base Case scenario, WB6 region has a positive net export balance with neighbouring countries: this is mainly explained by the relatively cheaper generation costs of WB6 plants, for hydro plants as well as for thermal plants, thanks to the absence of CO2 pricing.[146] Volume of net export is even increasing following the commissions of several new thermal plants in Bosnia and Herzegovina, North Macedonia and Serbia in 2024/2025. On a country level, only Montenegro features a significantly negative net export balance, whereas Bosnia and Herzegovina and Serbia feature the highest net export balance.

C.9 In the EU ETS Energy Only scenarios, the situation differs from the previous scenario. Indeed, as soon as a CO2 price is implemented in WB6 Contracting Parties (from 2025 in the EU ETS 2025 Energy Only scenario or from 2030 in the EU ETS 2030 Energy Only scenario), lignite plants make significant losses and do not invest to refurbish. It results in several lignite power plant closures, as soon as late 2023 in the EU ETS 2025 scenario or in late 2027 in the EU ETS 2030 scenario (explaining the lower volume of lignite generation on Figure 32), which are offset by higher imports from neighbouring countries: overall, the WB6 region becomes a net power importer. Whereas it is expected to export 35% of its consumption in 2030 in the Base Case scenario, the WB6 region import 30% of its consumptions in 2030 in the two EU ETS Energy Only scenarios.

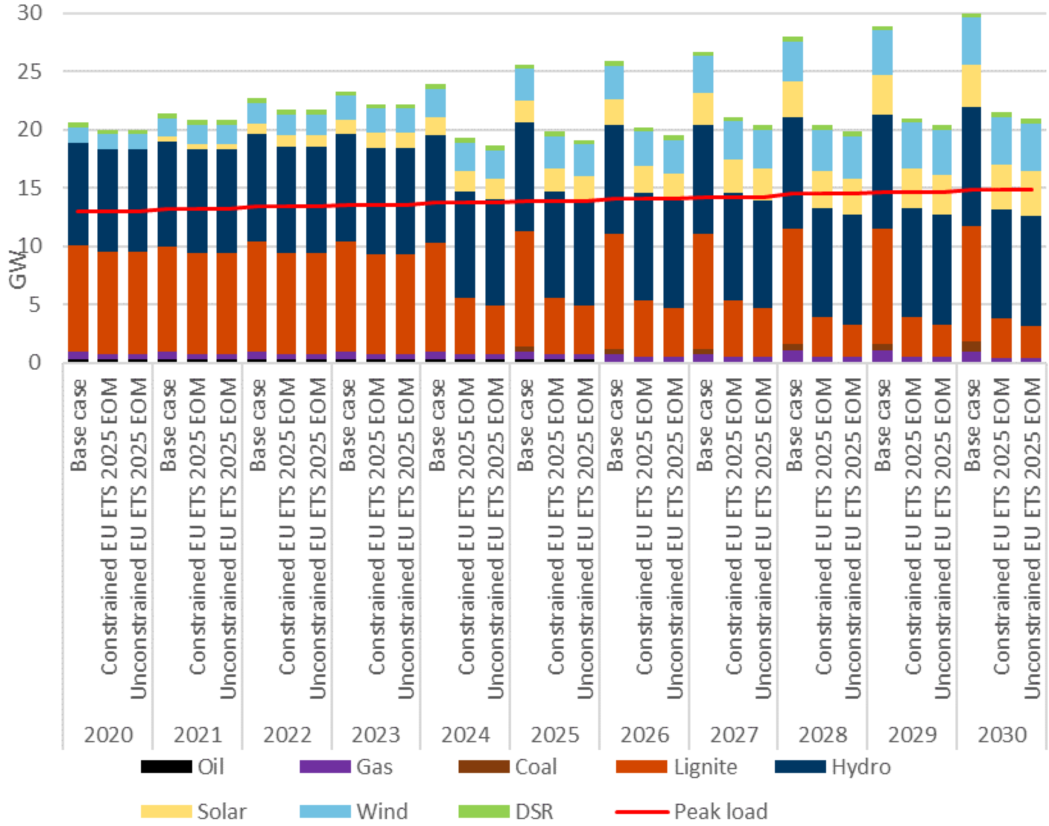
C.10 While lignite installed capacity is the same between both EU ETS Energy Only scenarios from 2028 onwards (because of the IED limits), generated volumes are not the same in 2028 and 2029. This is due to the absence of CO2 pricing for these years in the EU ETS 2030 Energy Only scenario. In this scenario, remaining plants are more competitive (compared to foreign capacity) since they are not subject to a CO2 price: as a result, they tend to produce more. In 2030, the implementation of the EU ETS market reduces their competitiveness: their generation decrease and become equal to the generated electricity in the EU ETS 2025 Energy Only scenario.

C.11 Finally, Figure 33 and Figure 34 illustrate the installed capacity outlook and generation outlook for the EU ETS 2025 Energy Only scenario with constrained cross-border import. Regarding

146 All neighbouring countries participate to the EU ETS market and are subject to a CO2 pricing.

installed capacity, fewer lignite plants are closed once the EU ETS mechanism is introduced. On the generation side, imports are slightly lower in the constrained cross-border scenario compared to the unconstrained scenario, given the implemented limits on import for Serbia, Montenegro and Bosnia and Herzegovina. Decreased imports are offset by higher generation from local lignite plants.

Figure 33: Installed capacity outlook in the WB6 region, per technology in the constrained EU ETS 2025 Energy Only scenario (GW)



Source: *FTI-CL*

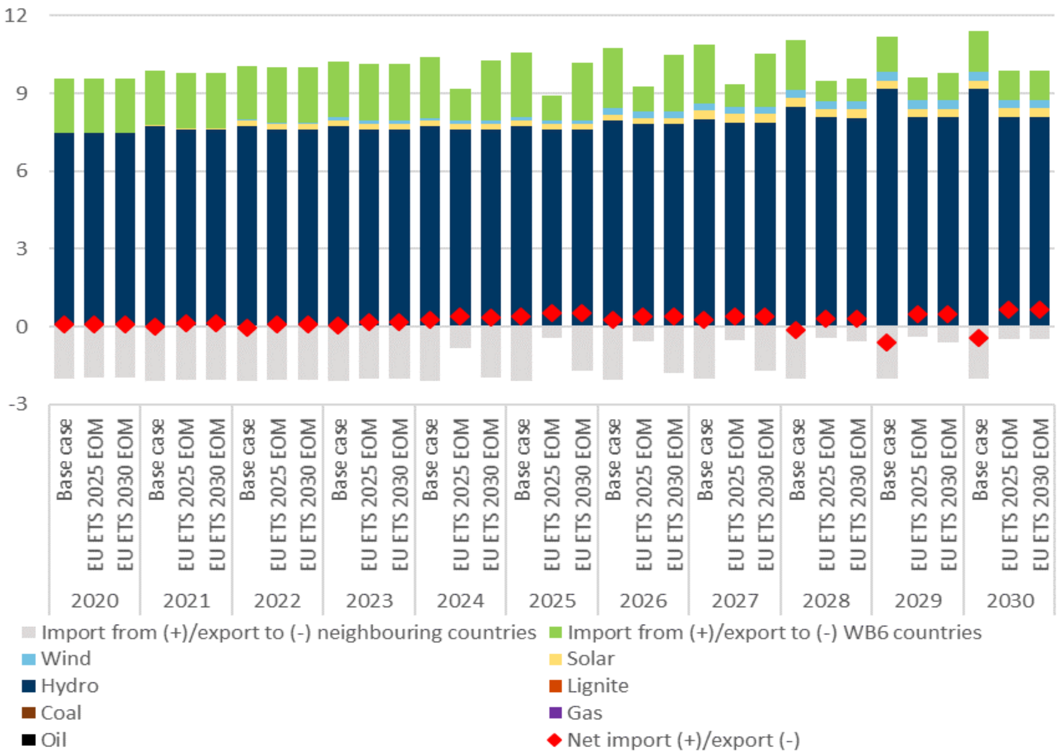
Figure 34: Generation outlook in the WB6 region, per technology in the constrained EU ETS 2025 Energy Only scenario (TWh)

Source: FTI-CL

Country by country results

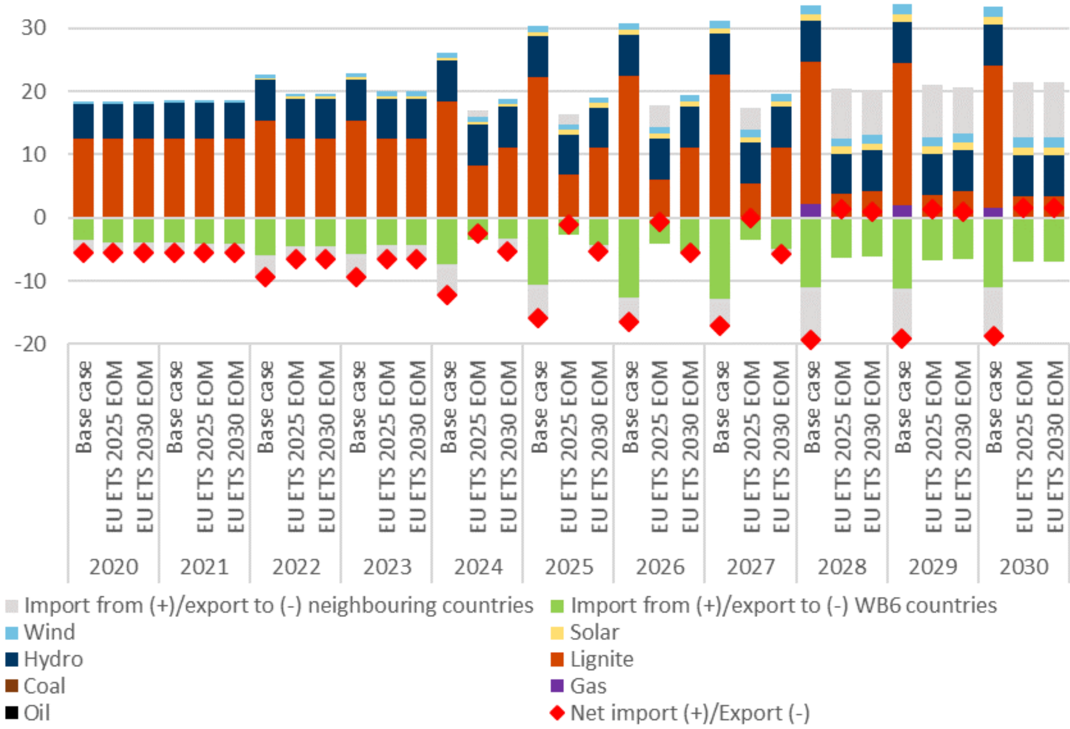
C.12 Figure 35 to Figure 40 below illustrate the generation outlook for each WB6 Contracting Party per technology and for the three studied scenarios.

Figure 35: Generation outlook for Albania, per technology and scenario (TWh)



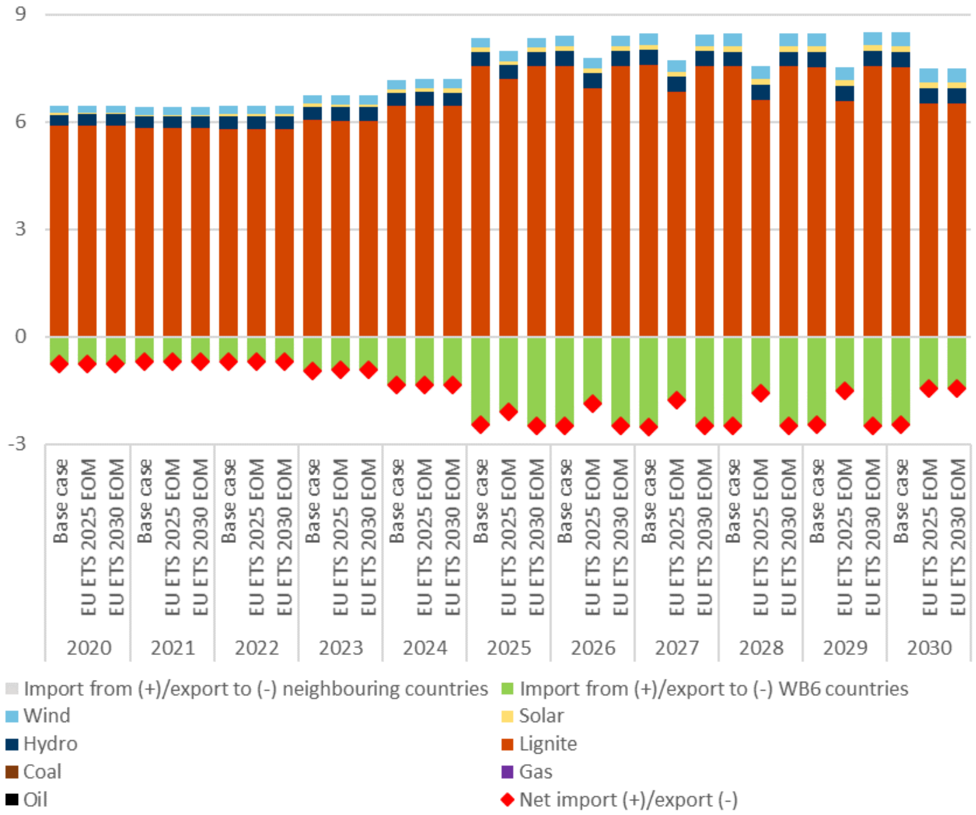
Source: *FTI-CL*

Figure 36: Generation outlook for Bosnia and Herzegovina, per technology and scenario (TWh)



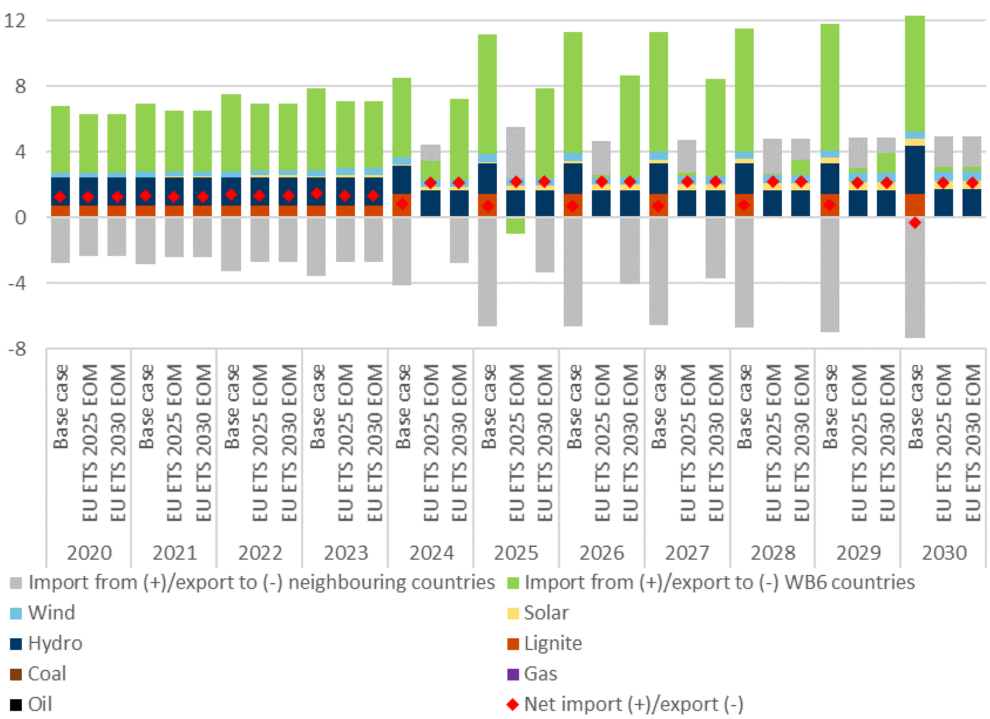
Source: *FTI-CL*

Figure 37: Generation outlook for Kosovo*, per technology and scenario (TWh)



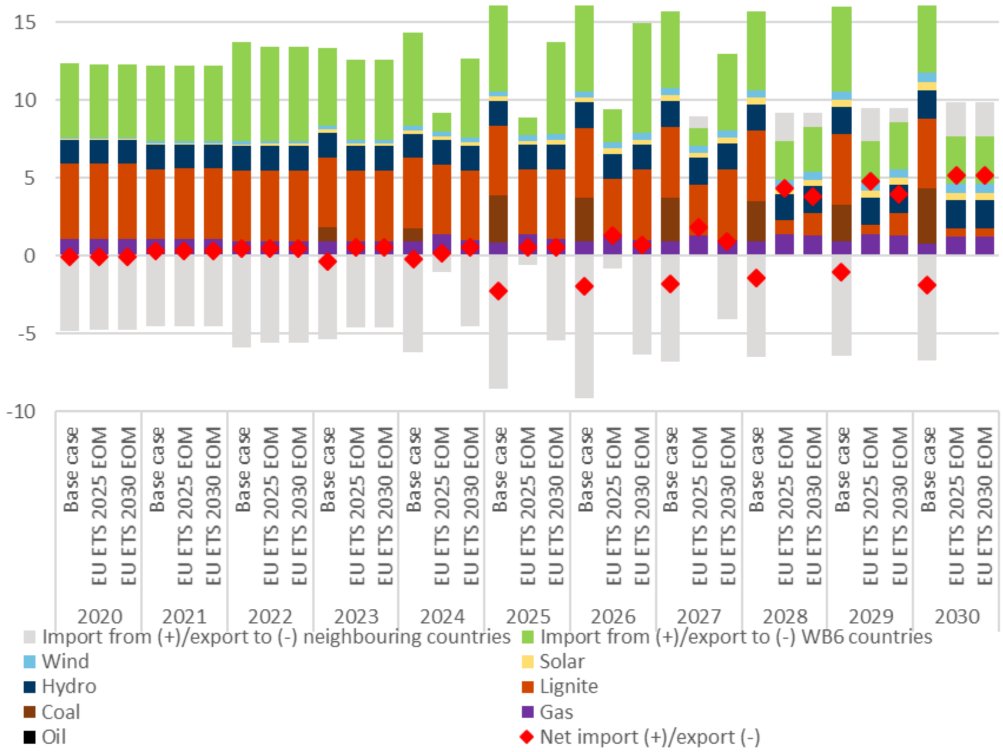
Source: FTI-CL

Figure 38: Generation outlook for Montenegro, per technology and scenario (TWh)



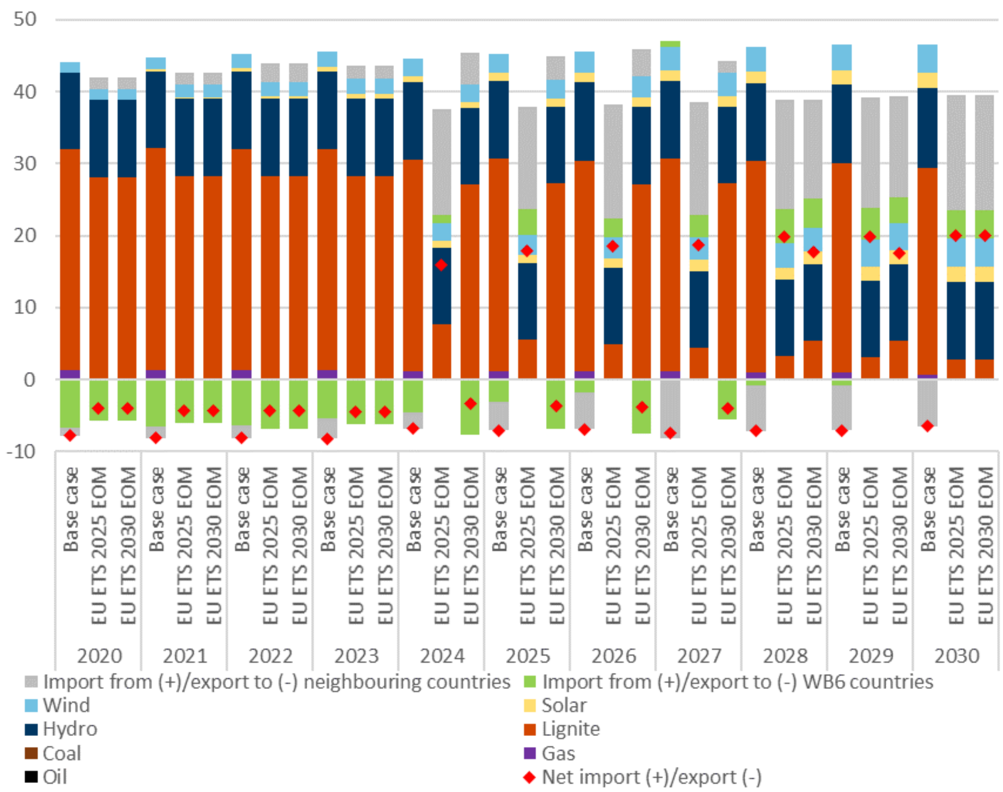
Source: FTI-CL

Figure 39: Generation outlook for North Macedonia, per technology and scenario (TWh)



Source: *FTI-CL*

Figure 40: Generation outlook for Serbia, per technology and scenario (TWh)



Source: *FTI-CL*

Adequacy analysis – country by country results

Albania

C.13 In the base case scenario, the Albanian power market features a positive margin throughout the horizon when accounting for import capacity. Without the import contribution, Albania would not be able to meet its demand during peak hours. This is explained by the relatively low statistical availability of hydro plants during peak hours (57% based on historical data) while hydro accounts for the quasi-totality of installed capacity in Albania.

C.14 When studying the EU ETS 2025 and 2030 Energy Only scenarios, the impact of CO2 pricing is slight for Albania given that there are no lignite plants in this country: the margin decreases by 200 MW between 2020 and 2030. The decrease is due to cancelled new projects in large hydro plants which are assumed not economic in an energy-only market design.

Bosnia and Herzegovina

C.15 Bosnia and Herzegovina experiences positive margin in the base case scenario, even when removing the contribution of import. A current overcapacity in thermal plants and a high availability of hydro (69%) explain the result. The margin is even increasing throughout the horizon thanks to expected new thermal projects (e.g. Banovici, Kakanj 8, Ugljevik 3) despite the increasing peak demand and the decommissioning in 2023 of several plants which are in the LCPD opt-out list. In particular, it should be noted that results with and without imports are exactly the same. In the base case scenario, Bosnia and Herzegovina does not rely on imports during peak hours as it has enough available capacity.

C.16 In the EU ETS 2025 and 2030 Energy Only scenarios, results are quite different. Introducing a CO2 price would deeply impact the economic situation of lignite plants in Bosnia and Herzegovina: new projects are cancelled and several existing plants are decommissioned since their refurbishment to comply with environmental norms (LCPD or IED) is not profitable. As a result, the system margin starts decreasing as soon as 2022 (when Tuzla 7 would have become operational). In the EU ETS 2025 scenario, closures occur as soon as late 2023 (since plants are not compliant with the LCDP), which explains the sharp decrease in system margin in 2024, whereas closures happen only in late 2027 in the EU ETS 2030 Energy Only scenario. As a result, Bosnia and Herzegovina needs to rely on imports during peak hours to cover demand, as soon as 2028 in both EU ETS Energy Only scenarios. The impact of the new cross-border lines with Croatia (in 2028), Montenegro (in 2025/2026) and Serbia (in 2026) can also be noticed by comparing the solid and dotted blue lines in the EU ETS 2025 Energy Only scenario: even if the system margin without import decreases due to lignite closures, the system margin with import remains stable thanks to the higher import capacity.

Montenegro

C.17 In the base case scenario, the Montenegrin power market features a negative margin throughout the horizon, turning positive when accounting for import capacities. This is explained by the importance of hydro capacity in the country, whose availability during peak hours is low (42%). However, when imports are considered, the system margin becomes positive. It even increases throughout the horizon following commissioning of new lines with Italy, Serbia and Bosnia and Herzegovina in 2024, 2025 and 2026.

C.18 In the EU ETS 2025 Energy Only scenario, the CO2 price has slight impacts on the system margin (compared to other countries). Its introduction makes the refurbishment of the existing Pljevlja plant unprofitable, which then closes in 2023. Similarly, several new projects of large hydro are cancelled in the EU ETS 2025 Energy Only scenario given they are assumed not economic in an energy-only market design. Results in the EU ETS 2030 Energy Only scenario are exactly the same: indeed, as soon as a CO2 price is expected, either in 2025 or 2030, investment and refurbishment decisions are expected to be unprofitable and then not made.

North Macedonia

C.19 North Macedonia is quite similar to Albania and Montenegro in the base case scenario: it relies on imports to cover demand during peak hours. Despite several new coal projects (700MW), the margin remains constant up to 2029 given the increasing peak demand (+300 MW between 2020 and 2030) and the decommissioning of Negotino and Oslomej plants.

C.20 Like for Bosnia and Herzegovina, the implementation of the EU ETS market has significant impacts in North Macedonia as it leads to several cancelled projects (e.g. Oslomej in 2023) and closures (e.g. Bitola 1 and Bitola 2 in late 2027 in both scenarios). As a result, system margin decreases significantly in both EU ETS Energy Only scenarios but, thanks to imports, remains positive or slightly negative until 2030.

Serbia

C.21 Serbia experiences a negative system margin in the base case scenario when imports are not considered. Even if the total installed capacity (8,000 MW in 2020) is sufficient to cover peak demand (6,300 MW in 2020), about half capacity consists in hydro or wind capacity: their availability during peak hours is lower than that of lignite plants (average availability of hydro plants is 72% and that of wind capacity is 15%), which explains why Serbia has a negative margin during peak hours. This margin even decreases throughout the studied horizon given (i) closures of plants on the LCPD opt-out list in 2023, and (ii) the increasing peak demand. However, when accounting for imports, the system margin becomes positive and even increases in 2026 thanks to the new cross-border line with Bosnia and Herzegovina.

C.22 Like Bosnia and Herzegovina and North Macedonia, Serbia is one of the countries most affected by the introduction of CO2 pricing given the importance of lignite plants in the Serbian capacity mix. The expected implementation of CO2 pricing has impacts on lignite plants as soon as 2020: new projects of Pancevo and Kostolac-B 3, which are forecast for 2020, are assumed to be cancelled in the EU ETS Energy Only scenarios given their negative NPV. This explains the lower system margin in the EU ETS 2025 and 2030 Energy Only scenarios, compared to the base case scenario. More importantly, once Serbia enters the EU ETS market, the economic situation of existing lignite plants deeply worsens. Several plants need to close since they cannot refurbish (for instance, Nikola Tesla A and B in late 2023 and Kostolac B in late 2027 in the EU ETS 2025 Energy Only scenario). It causes a major drop in the system margin and a negative margin equal to -4,000MW when imports are not considered. Even with imports, Serbia is expected to experience a negative margin, from 2024 onwards in the EU ETS 2025 Energy Only scenario and from 2028 onwards in the EU ETS 2030 Energy Only scenario, which may ultimately translate into shortages. In the EU ETS 2025 Energy Only scenario, system margin is slightly positive in 2026 and 2027 thanks to the new line with Bosnia and Herzegovina.

Kosovo*

C.23 Finally, a focus is made on the situation in Kosovo*. In the base case scenario, the Kosovar power market features a negative margin throughout the horizon, explained by the low level of installed thermal capacity (900 MW) compared to the peak demand (1,200 MW). However, when accounting for import capacities, the system margin becomes positive. The importance of the full use of the cross-border with Albania is highlighted by the system margin increase in 2021:[147] it raises the margin by 50%.

C.24 The implementation of the EU ETS market does not have any consequences on the Kosovar power system: that is why the orange and blue lines overlap in both EU ETS scenarios. Indeed, it is assumed that new plant Kosovo e RE will be built regardless of the market conditions, given the advanced status of the tender. Its commissioning is not challenged by the CO2 pricing. For existing plants, the Kosovo A plant is expected to close in all cases (i.e. with or without CO2 pricing) in 2023 since it is in the LCPD opt-out list. Finally, Kosovo B is assumed to be profitable enough, even with a CO2 pricing, to stay operational during the whole studied horizon.

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147 While the full technical transmission capacity between Albania and Kosovo* is already available (600 MW), only 200 MW are effectively used due to the dispute between the Serbian and Kosovar TSOs. We assume that this situation will be solved in 2021.

Appendix D

Electricity sector regulation in WB6 Contracting Parties and planned market reforms

Introduction

D.1 This appendix written by DLA Piper presents the country-specific details collected on the current state of the electricity sector regulation in WB6 Contracting Parties and planned reforms.

Current situation with the development of electricity sector in WB6 Contracting Parties

D.2 Below we present the current state of the electricity sector development in WB6 Contracting Parties, in particular details are provided on the following:

- Structure of the markets;
- Development of wholesale markets;
- Balancing and ancillary services markets;
- Regulated prices; and
- DSR development.

Structure of the market

- **Albania.** State-owned generator company KESH owns 66% of total functional installed capacity (in hydro and one non-functional TPP). KESH's generation covers between 45% - 70% of domestic demand. Another 100% state-owned company for the universal service supply (FSHU) acts as the country's retail public supplier and last resort supplier. KESH is charged with PSO obligations to reserve volumes for FSHU's regulated customers' needs. DSO accounting and functional unbundling is yet not complete and subject to infringement proceedings by the Energy Community Secretariat. In 2018, the former OSHEE underwent a restructuring process whereby it was legally split into three different companies (i) OSSH for distribution; (ii) FSHU for supply of regulated customers under universal service; (iii) FTL for the supply on the free market (yet to be finalised). The distribution OSSH is legally but not yet functionally unbundled from the supply. Furthermore, there has been no competitive procedure for the designation of the Last Resort Supplier (LRS). The FSHU acts temporarily as the LRS.

- **Bosnia and Herzegovina.** State-owned ERS owns about 67% of installed capacity (TPP and hydro combined) in Republicka Srpska, and the State-owned entities EPBiH and EPHZBH own approximately 97% of installed capacity in Federation of Bosnia and Herzegovina (FBiH) (in TPP and hydro combined). State owns four out of five lignite/coal-fired TPPs,[148] and three lignite/coal mines. The ERS, EPBiH and EPHZBH are quasi-monopoly suppliers in their respective geographic areas serving almost 100% of the total final customers. The TSO is not unbundled as required by the Third Package. Supply companies in both states are not unbundled from distribution.

- **Kosovo*.** The 100% state-owned company Kosovo Energy Corporation (KEK) owns the two main lignite-fired power plants Kosovo A (5 units) and Kosovo B (2 units), and the Ujmani HPP. It provides about 95% of electricity produced in Kosovo, as well it controls the lignite reserves. The Kosovo Electricity Supply Company (KESCO) owned by the Turkish Calik Limak Energy, is the dominant undertaking on the retail supply, on both regulated and free segments. KEK is charged with PSO obligations to reserve volumes for KESCO's regulated customers' needs. The TSO is unbundled in line with the Third Energy Package. Although the DSO is formally unbundled from supply, concerns have been raised on its effective functional unbundling.

- **Montenegro.** The majority state-owned company "Elektroprivreda Crne Gore" (EPCG) owns almost 90% of installed capacity, including the thermal power plant Pljevlja TPP (22,5%), the hydro power plants (67,5%) as well as a 100% shareholding in the Pljevlja coal mine. EPCG vertically integrated supply unit is dominant on wholesale level, and in monopoly position on retail markets. The TSO/DSO are unbundled in line with the Third Package.

- **North Macedonia.** The state-owned AD ESM is the largest electricity producer, which owns the country's two TPPs (representing 50.18% of the total installed capacity), eight HPPs (560,8 MW), the wind power plant Bogdanci (36.8MW). ESM's 100% owned subsidiary holds the coal/lignite mines. AD ESM provides about 90% of the total domestic production. In 2017, its generation covered 54.24% of domestic demand. The retail PSO supplier is EVN. AD ESM is charged with PSO obligations to reserve volumes for EVN's regulated customers' needs. The TSO/DSO are unbundled in line with the Third Package.

- **Serbia.** The state-owned "Elektroprivreda Srbije (EPS) owns more than 98% of installed capacity (all coal/lignite fired TPPs representing 56% of installed capacity as well other hydro and RES capacities). EPS procures approx. 70% of generation from coal/lignite and approximately 30% from HPPs. EPS' 100% subsidiary owns several coal/lignite mines. The State also holds the PEU "Resavica' underground coal mines. EPS is present as

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148 RITE Gacko and RITE Ugljevik (600 MW), TE Tuzla and TE Kakanj (1,256 MW)

dominant undertaking on both generation and supply (i.e. holding a quasi-monopolistic position). At retail level, EPS supplies 97.5% of the total final end users' demand. In 2017, EPS' covered 98% of domestic demand in Serbia. The TSO, EMS is not unbundled from EPS in line with the Third Package, though AERS adopted a certification decision.. Furthermore, the DSO is not functionally unbundled from supply.

Wholesale markets

- **Albania.** Currently, the state-owned generator KESH sells to FSHU, the state-owned retail public supplier, 70% to 90%[149] of its generation *via* bilateral contracts at quasi regulated prices to cover supply needs for regulated customers.[150][151] Furthermore, approximately 80% of volumes generated by independent power producers (IPPs) are purchased by the FSHU based on power purchase agreements (PPAs) at fixed electricity price' determined by ERE. KESH releases surplus output (20% to 30%) or purchases volumes to cover outages on the free wholesale market via tenders.[152] Traders' activity consists mainly of

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149 See regulator's ERE Report for year 2018 http://www.ere.gov.al/doc/Raporti_vjetor_ERE_2018_perfundimtar.pdf

150 Council of Ministers' Decision No. 244 of 30 March 2016 as amended on 8 December 2017, on Public Service Obligations (PSO); Article 5(2) of which imposes an obligation on KESH to sell to OSHEE and on OSHEE to purchase on the first place from KESH, electricity volumes for supply under universal service and last resort. In these KESH-OSHEE exclusive contracts, volumes are to be determined by the Assembly of Shareholders of KESH (i.e. Ministry competent for energy) taking into account the average historic annual production of the last ten years based on information provided by ERE and on a rational exploitation of the KESH's generation capacities; and price to be determined by the Assembly of Shareholders of KESH (i.e. Ministry competent for energy) taking into account the reasonable costs anticipated in the economic program of the company as well as the impact on prices for customers that enjoy universal service. On this basis KESH-OSHEE concluded the two most recent yearly contracts, approved by the regulator ERE, the first covering year 2018 extended until February 2019 the second for the period from March 2019 to December 2019. ERE has started proceedings for the approval of a similar contract for 2020. In cases where KESH cannot procure said volumes to OSHEE, the latter has the obligation to compensate OSHEE for any such volumes purchased on the de-regulated market at the average purchase price incurred by OSHEE on the de-regulated market (art.9). Under Article 5(4) of Decision 244, any volumes of electricity generated by KESH which exceed OSHEE's demand as supplier is sold to OSHEE in its capacity as DSO to cover the network losses, based on the average price of Hungarian PX for the period in which the electricity is delivered in baseload profile, as published on the website of the power exchange. in contracts approved by ERE http://www.ere.gov.al/doc/VENDIM_NR.16_2019.pdf. On the basis of ERE's regulation adopted by Decision No. 103. 23 June 2016, OSHEE carries out an electricity transparent, competitive, non-discriminatory procurement handled via an IT platform which automatically evaluates the bids and designates the winner.

152 See regulator's ERE Report for year 2018 http://www.ere.gov.al/doc/Raporti_vjetor_ERE_2018_perfundimtar.pdf

cross-border trade to sell the incumbent's surplus or provide volumes to cover shortages.[153]

- **Bosnia & Herzegovina.** The dominant generators' ERS /EPBiH/ EP HZHB reserve 50% to 70% of their generated volumes for their vertically integrated public supplier units to cover regulated customers' needs. ERS/EPBiH/EP HZHB offer 30% to 50% of their generated electricity on the free market *via* tenders on monthly, quarterly or yearly basis. Traders' activity consists mainly in participation in cross-border trade to sell the incumbents´ surplus or provide volumes to cover shortages. Public suppliers' units set prices at retail level at a level below market-based price.[154] ERS from Republika Srpska participates on the Serbian PX, i.e. the SEEPEX.

- **Kosovo*.** The dominant generator KEK sells 70% to 90% of its generated volumes to the dominant public supplier KESCO under public service obligations (PSO), to cover needs of regulated customers, at a quasi-regulated price, based on historic regulated prices, after opinion by the regulator ERO. KEK offers 10% to 30% of its volumes or purchases shortages on the free market, *via* tenders or brokers on monthly or quarterly basis. Traders' activities mainly consist in cross-border trade to the sell incumbent's surplus or provide volumes to cover shortages.

- **Montenegro.** The dominant generator, EPCG, reserves 70% to 90% of its volumes for its integrated supply unit to supply, within intra-group transfer, to cover needs of retail regulated customers. Regulated retail prices are set below marked-based level. EPCG sells 10 to 30% of its output or buys shortage volumes *via* tenders or bilateral contracts on a monthly, quarterly or yearly basis. Approximately 90% of volumes on the wholesale market are exchanged within integrated units of EPCG. Traders' activities mainly consist in cross-border trade to sell the incumbent's surplus or provide volumes to cover shortages**.** According to the 2017 regulator's report,[155] EPCG had 100% share in the retail sector.[156] Due to structural barriers, there are few chances that other registered suppliers become active on the market in the short-term.[157]

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[153] See regulator's ERE Report for year 2018 http://www.ere.gov.al/doc/Raporti_vjetor_ERE_2018_perfundimtar.pdf

[154] See regulator's report for year 2018 (The Report on Activities of the State Electricity Regulatory Commission in 2018) https://www.derk.ba/en/godinji-izvjetaji-derk-a

[155] See Financial Report of the Montenegrin Regulatory Agency for Energy for 2017 year http://regagen.co.me/cms/public/image/uploads/2018.04.27_PREDLOG_FINANSIJSKOG_IZVJESTAJA_SA_IZVJESTAJEM_O_RADU_RAE_za_2017._g_.pdf (visited 15. July 2019)

[156] See Decision on adoption of the Financial Report of the Montenegrin Regulatory Agency for Energy for 2017 year published in "Official Gazette of Montenegro, No. 2/2017" dated 10 January 2017. (visited 15.07. 2019)

[157] See Report on the energy sector status in Montenegro in 2017 (visited 15.07.2019)

- **North Macedonia.** The dominant state-owned generator AD ESM[158] sells 50% to 70% of its generated volumes to the retail public supplier, EVN under a PSO to cover needs of regulated customers, at wholesale regulated prices set by the regulator ERC (up to the end of 2018). Starting on 1 January 2019, the obligation of the incumbent generation company ESM to provide electricity for supply to households and small customers under universal supply and supply of last resort at regulated price, was replaced by an obligation of ESM to offer a certain share of its production at market prices to the universal supplier. The national primary energy law sets out the gradual reduction of this share (i.e. 80% in 2019, up to minimum 30% in 2025).[159] In accordance with the Rules for Purchase of Electricity for the Universal Supplier, EVN can purchase electricity from more than one supplier,[160] in North Macedonia or abroad by concluding bilateral agreements or on the power exchange PX.[161] EVN already announced a public call for admission of bidders to a qualification system for purchase of electricity and created a list of qualified bidders.[162] It is however yet to be seen whether ESM will gradually reduce the share of electricity offered on public auction to the universal supplier EVN. In 2018, EVN purchased 90% of volumes from ESM; 6,24% from preferential producers of RES; and the rest was purchased on the free electricity market.[163] In 2017, EVN purchased 94% of electricity volumes from ESM. Volumes generated by privileged renewable producers are purchased by the Offtaker (i.e the transmission system operator MEPSO under PPAs). AD ESM offers 30% to 50% of its generated volumes on the free market, *via* bilateral contracts, tenders, OTC or transactions power exchanges (PX) in other countries. Traders' activities consist mostly of cross-border trade to sell the incumbent's surplus or provide volumes to cover shortages.

- **Serbia.** The incumbent state-owned generator EPS reserves 50% to 70% of its volumes for its integrated supply unit, within intra-group transfer, to cover the needs of retail regulated customers. EPS offers 30% to 50% of its generation or buys shortages on the free market *via* bilateral contracts, tenders, OTC or PX transactions. EPS participates in SEEPEX and other regional platforms to optimize its portfolio. At the end of 2017, 14

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158 Please note that due to the name change of the country form Republic of Macedonia to Republic of North Macedonia, state institutions had to change their names. Consequently, ELEM (Elektrani na Makedonija) was renamed to ESM (Elektrani na Severna Makedonija).

159 Article 237 of the Energy Law (Published on 28 May 2018 in "Official Gazette of the Republic of Macedonia No. 96/2018, as amended

160 Decision on approval of a model Agreement, adopted on 8 May 2019.

161 Article 2, Rules for Purchase of Electricity for the Universal Supplier (Published on 14 September 2018 in "Official Gazette of the Republic of Macedonia No. 172/18, as amended.

162 Public call for admission of bidders to a qualification system for purchase of electricity. List of qualified bidders admitted in the qualification system via the web-based platform according to OKS 01/19 h

163 Annual Report by the Energy Regulatory Commission for 2018, published in April 2019, pg. 27.

members from 9 countries were active on Serbian Power Exchange (SEEPEX). In 2017, 17% of the volumes traded on the wholesale market was routed *via* the SEEPEX. Volumes routed on the SEEPEX reached 2.89% of total volumes delivered to final customers, and 6.27% of volumes delivered to de-regulated customers on the free market. ERS from Republika Srpska participates on the SEEPEX.

Balancing and ancillary services

- **Albania.** Based on the Power Sector Law,[164] the Provisional Rules of Albanian Electric Power Market,[165] the Transitional Rules for Electricity Balancing Mechanism,[166] and the Transmission Network Code,[167] the transmission system operator, OST is responsible for procuring balancing and ancillary services.[168] The Government of Albania imposes public services obligations (PSO) on KESH to make available necessary balancing capacity reserves, in accordance with a regulated contract approved by the regulator. The price for balancing capacity including automatically activated secondary reserve manually activated tertiary reserve is regulated on yearly basis. The procurement of balancing energy is not done through market-based procedure. KESH is obliged to offer all of its available capacity. The price for balancing energy is determined in the bilateral contract between KESH and OST,[169] on yearly basis, based on the HUPX day-ahead prices multiplied by different factors.[170] The cost for capacity procurement is recovered through the network tariff. The costs for balancing energy dispatched from the secondary or tertiary reserves are covered under the balancing mechanism via BRPs. Imbalance price is determined on the basis of HUPX day-ahead prices multiplied by different factors. Other balancing services providers may also participate. RES generators are exempt from balancing responsibility and all the costs for balancing RES generation are passed through to end-customer in universal supply tariffs.

- **Bosnia and Herzegovina.** The transmission system operator NOS BiH is in charge of procuring balancing capacity (including secondary and tertiary reserves), based on competitive process, through a public purchase procedure. The submitted bids are ranked by offered bid price and selected bids are remunerated by the bid price (i.e. pay-as-bid). All participating generating units are obliged to offer all of their available reserve capacity.

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164 http://www.ere.gov.al/doc/Law_on_energy_sector_approved_on_43.2015.pdf

165 https://www.ost.al/wp-content/uploads/2016/04/Provisional-Market-Rules.pdf; in force from 25.08.2016

166 http://www.ere.gov.al/doc/Transitional_Rules_for_Electricity_Balancing_Mechanism.pdf; which in accordance with Article 16 there of *will apply until the International Finance Corporation sponsored final balancing rules enter into force."*

167 http://www.ere.gov.al/doc/Transmission_Network_Code_14.06.2018.pdf

168 See also the ECRB Report 'Electricity balancing mechanisms in the Energy Community', April 2019

169 For the year 2019, approved by ERE Decision No.84, 30.05.2019 http://www.ere.gov.al/doc/VENDIM_NR.84_2019.pdf

170 See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

The only providers of these capacities are however the three dominant market participants, namely EP BIH, EP HZHB and ERS. The cost for capacity procurement is recovered through end customers prices. The procurement of balancing energy is market-based process. Price caps determined by the regulator SERC apply to bids for reserve activation. The costs for balancing energy dispatched through the secondary or tertiary reservse are settled under the balancing mechanism. The imbalance price is defined on the basis of marginal price for activated secondary and tertiary reserves and the price coefficient defined is by the regulator, SERC.[171] There is also balancing cross-border cooperation, based on agreements with Croatia, Slovenia and Serbia.

- **Kosovo*.** The transmission system operator KOSTT is responsible for the procurement of balancing and ancillary services.[172] The market rules allow for the participation of all market participants that meet set technical requirements. The dominant generator KEK is however the only market participant. Prices for reserve capacity are regulated. Where required, as a last resort measure. Kosovo has no adequate reserves for secondary control, therefore, a part of needed reserve capacity is provided by hydropower plants in Albania, and a part by TPPs Kosovo. As there are no flexible units, Kosovo has no generating unit that can provide tertiary regulation. Where it may not ensure system balance based on reserves in Kosovo* and/or Albania, as a last resort measure KOSTT activates load shedding. To the extent of our knowledge, KOSTT does not remunerate the demand side parties affected by the load shedding. Prices for balancing reserve capacity are not regulated, but set through bilateral contracts. The cost for capacity procurement is recovered through the network tariff. Within the availability of electricity reserves' in Kosovo*, the procurement of balancing energy is done through market-based procedures and the price for balancing energy is set via day-ahead auctions. The costs for balancing energy are recovered under the balancing mechanism via BRPs. The imbalance price is set as a hybrid, based on offers but also linked with HUPX day-ahead prices.[173] [174] Each market participant is BRP. RES generators are not fully exempt from balancing responsibility, however may create balancing groups. The costs of RES imbalance are shared between RES generator (25%) and the remainder passed through to grid-users.

- **Montenegro.** The transmission system operator is responsible for procuring balancing and ancillary services.[175] The incumbent, EPCG, provides reserve capacities at 50 MW,

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[171] See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

[172] See also the ECRB Report 'Electricity balancing mechanisms in the Energy Community', April 2019

[173] (a) When system is short and there is no offer activation, imbalance price is the HUPX price increased by 30 %; (b) when system is long and there are no bid activation, imbalance price is HUPX price decreased by 30 %; (c) there is activation of offers, imbalance price is calculated as weighted average.

[174] See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

[175] See also the ECRB Report 'Electricity balancing mechanisms in the Energy Community', April 2019

a large customer provides balancing services through demand response. The regulator sets a regulated price for secondary and tertiary reserves capacity every three years. The regulator applies penalties in case of non-availability of contracted reserve or contracted DSR. The cost for capacity procurement is recovered through network tariff. The procurement of balancing services is market based. Any bid must be less than a determined price cap, set as double value of average price of export or import (whichever is higher) from the year preceding the year in which the contract is made.[176] The costs for balancing energy are covered under the balancing mechanism *via* BRPs. Imbalance prices are set based as the weighted average price for activation of the secondary and tertiary reserves and compensation of unintentional deviations.[177]

- **North Macedonia.** The transmission system operator, MEPSO is responsible for procuring balancing and ancillary services.[178] The procurement of balancing services is market based, however, the State imposes PSOs on ESM to offer all of its available reserve capacity for ancillary activation. Prices for secondary and tertiary reserve capacity are not regulated, but determined as "pay as bid". The cost for capacity procurement is recovered through the network tariff. The costs for balancing energy dispatched by secondary or tertiary reserve are settled under the balancing mechanism. The imbalance price is defined on the basis of the weighted average prices of tertiary and secondary activated reserves both for positive and negative direction.[179] All market participants are BRPs. RES generators are exempt from balancing responsibility. The costs of RES imbalance are passed through to grid users.

- **Serbia.** Based on the current framework, i.e. the Energy Law,[180] Market Code[181] and the Grid Code,[182] the transmission system operator EMS is responsible for procuring balancing and ancillary services.[183] The TSO rules (adopted by the TSO upon approval of the regulator) determine needs for secondary reserve at 160 MW, for positive and negative tertiary reserves at 300 MW and 150 MW, respectively. Procurement of balancing capacity is not done through a market-based procedure. Offering of all available

176 Methodology for determining prices, deadlines and conditions for provision of ancillary services and balancing services for transmission system for electricity, REGAGEN, 2016

177 See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

178 See also the ECRB Report 'Electricity balancing mechanisms in the Energy Community', April 2019

179 See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

180 http://aers.rs/FILES/Zakoni/Eng/EnergyLaw%20SG%20145-14.pdf

181 http://ems.rs/media/uploads/2017/Pravila%20o%20radu%20trzista/Market%20Code%2026.04.2017.-%20English%20version%20Unofficial%20translation.pdf

182 http://ems.rs/media/uploads/2018/Pravila%20o%20radu%20prenosnog%20sistema/GRID_CODE_28122017_EN_radna_ve.pdf

183 See also the ECRB Report 'Electricity balancing mechanisms in the Energy Community', April 2019

reserve capacity is mandatory for all generating units, that meet specific technical characteristic. EPS is the only provider of balancing capacity including for automatically activated secondary and manually activated tertiary reserves. In 2017, it reserved about 8% of its functional capacities for ancillary services. The regulator determines the price for capacity availability on annual basis.[184] Costs for capacity availability are passed through to final customers through network tariffs. Procurement of balancing energy is done through a market-based procedure; however, specific caps apply for bids of the dominant participant EPS.[185] Any bid should be between the maximum range (500 EUR/MWh) and minimum 0.1 EUR/MWh.[186] Tertiary regulation is paid as pay-as bids. Secondary regulation is paid following specific rules.[187] The costs for balancing energy dispatched by capacity reserve are settled under the balancing mechanism. The imbalance price is set based on activated balancing energy, as the weighted average prices of tertiary and secondary activated regulation both for positive and negative direction.[188] All market participants that submit schedules to the TSO are registered as BRPs. Renewable generators are exempt from balancing responsibility and costs for RES balancing are passed-through to end customers.

Regulated prices

Albania

- **Wholesale prices**. Even though price regulation at wholesale level has been formally abolished, prices for wholesale supply between the generation company KESH and public supplier OSHEE for the supply of regulated customers remain to a certain extent still quasi-regulated as the ministry competent for energy in its capacity as sole shareholder in KESH, is obliged to set them on the basis of pre-determined principles established in the

[184] The regulator AERS sets prices for secondary and tertiary reserves based on an estimation of revenues the capacity provider (i.e. EPS) would have earned if capacity was not held in reserve, but had sold electricity on the power exchange at average annual futures' market prices for base-load production. In the 2017 'Report on the need to maintain price regulation for ancillary services', AERS justified such regulation based on (i) EPS being in a monopoly position on the national market for provision of secondary and tertiary reserves; and (ii) absence of sufficient cross-border exchange of ancillary except for emergency reserve and balancing.

[185] Prices offered for downward and upward should be within the spread of 30 €/MWh for range [-100MWh up to 100MWh]. Outside this range, normal caps apply.

[186] See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

[187] For secondary regulation price is determined as maximum price for activated tertiary regulation when secondary and tertiary regulation are of the same direction; if not, price is equal to price offered by dominant participant.

[188] See ECRB 'Report State of electricity imbalance price formation in the Energy Community', April 2019.

secondary legislation.[189] Furthermore, the costs incurred by the generator KESH in refurbishing the Vlora TPP are expected to be passed on to regulated customers.

- **Retail.** Retail prices for customers connected to 20 kV, 10 kV, 0.6 kV, 0.4 kV voltage are still regulated under the universal service supply; while prices for 35 kV customers remain regulated under the cover of last resort supply.[190] Save for 0.4 kV customers, remainder retail price regulation seems not compliant with the *acquis*.[191] All customers are granted eligibility right and are free to switch supplier.

D.3 The existing framework sets the principle that regulated retail prices should be set at cost-reflective level. However, the regulator appears to mostly set retail prices for regulated customers below real costs; at a level that does not account for contestability by other suppliers.

Bosnia and Herzegovina

- **Wholesale.** In the *Federation of Bosnia and Herzegovina*, wholesale prices are de-regulated. In *Republika Srpska*, wholesale prices are regulated. According to plans of April 2019, this should be phased out by way of the new Electricity Law which provides for generation price deregulation.

- **Retail.** In the Federation of Bosnia and Herzegovina and Republika Srpska retail prices for small customers and households are regulated.[192]

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189 The wholesale price of the state-controlled generator KESH for volumes reserves to the public supplier OSHEE for supply of regulated customers is defined by sole Shareholder in KESH, the minister competent for energy, on the basis of pre-determined principles of historic costs and social impact. Therefore, even though the regulator ERE does not explicitly regulate wholesale prices reserved for the supply of regulated customers, the existing framework imposes on the incumbent generator a number of social / policy considerations which are not market-based. See the Council of Ministers' Decision No. 244 of 30.03 2016 in Art. 5(2) and ECRB Report, 'State of Forward Markets in the Contracting Parties', November 2019, page 4 *"This Report states that although the price for this part of the generation portfolio is bilateral, it can be considered as regulated given that it is set on the basis of costs without any correlation with market prices."*

190 OSHEE still supplies 35 kV customers, in its capacity of last resort supplier (for a 2-year period). See also WB6 Electricity Monitoring Report, Energy Community Secretariat, May 2019, page 6.

191 Article 109(1) of the Albanian Power Sector Law provided for a gradual phase out of retail price regulation for electricity end customers. Starting from 2018, only customers connected to the 0.4 kV could enjoy universal service provided that ERE justified such need. Albanian authorities fell behind meeting these deadlines.

192 FBiH: Decision on tariffs for users on distribution system of EP HZ HB - http://www.ferk.ba/_ba/images/stories/2017/odluka_tarifni_stavovi_jpephzhb_procisceni_tekst_bs.pdf Rulebook on tariff methodology and tariff procedures- http://www.ferk.ba/_ba/images/stories/2013/tarifna_metodologija_2013_bs.pdf Reasoning attached to

*Kosovo**

- **Wholesale.** Wholesale prices for volumes sold by the incumbent generator KEK to the public supplier KEDS to cover needs of regulated customers are still quasi-regulated.[193] Moreover, the Kosova e Re PPA sets a fixed pre-determined wholesale price for electricity and availability over a 20-years period; costs of which are expected to be passed on to end-customers.

- **Retail.** Retail prices for 35kV and 10 kV customers are still regulated.[194] Based on a decision of March 2019, Kosovo*s regulator plans to phase out unjustified price regulation, for 35kV customers by 31 March 2020; and for 10 kV customers by until 31 March 2021.[195]

Montenegro

- There is no formal regulation of wholesale prices. However, most of the wholesale volumes are traded intra-group within units of the same undertaking EPCG; which is dominant on wholesale level and in monopoly position on retail level. At retail level, price of last resort supply is set by the regulator based on a reference market price.[196] The regulator sets methodology for determining universal and last resort supply prices.[197]

North Macedonia

- **Wholesale.** Starting 1 January 2019, the obligation of the incumbent generation company ESM to provide electricity for supply to households and small customers under universal supply and supply of last resort, was replaced by an obligation of ESM to offer a certain share of its production at market prices to the universal supplier. The Energy Law determines gradual reduction of this share (i.e. 80% in 2019, up to minimum 30% in 2025).

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the Rulebook on tariff methodology and tarif procedure
http://www.ferk.ba/_ba/images/stories/2013/tarifna_metodologija_obr_2013_bs.pdf
Decision on tariff rates for public supply in RS - https://reers.ba/wp-content/uploads/2019/05/Odluka_tarifni_stavovi_javno_snabdijevanje_RS_2016.pdf
Decision on price of energy for public supply - https://reers.ba/wp-content/uploads/2019/05/Odluka_o_cijeni_energije_za_javno_snabdijevanje_2016.pdf

193 See also ECRB Report, 'State of Forward Markets in the Contracting Parties', November 2019, page 6, In this report it is stated that, although the wholesale price for the part of the generation portfolio that is reserved for supply of regulated customers is bilateral, it can be considered as still regulated as it is set on the basis of historic regulated prices and approved by the regulator.

194 See also WB6 Electricity Monitoring Report, Energy Community Secretariat, May 2019, page 14

195 See ERO Guidance on Liberalization of the electricity market in Kosovo, adopted on 13 June 2018 and amended on 13 October 2018, in particular Article 8.

196 The Regulation was published in the "Official Gazette of Montenegro", no. 81/2018 dated from 20 December 2018. It entered into force on 28 December 28, 2018, and is applicable from 1 January, 2019. (visited 15 July 2019)

197 The methodology was published in the "Official Gazette of Montenegro", no. 83/2016 dated from 31 December 2016. and entered into force on 8 January, 2017. (visited 15 July 2019)

The Energy Regulatory Commission does not regulate the price for this sale, however, it adopts Rules for Purchase of Electricity for the Universal Supplier. In accordance with these Rules, the bidder offers a price, while EVN has an obligation to choose a supplier on the basis of the price.[198]

- **Retail.** The regulator has adopted a tariff system for the sale of electricity by the universal service supplier and the supplier of last resort.[199]

Serbia

- **Wholesale.** There is no formal regulation of wholesale prices. However, most of the wholesale volumes are traded intra-group within units of the same undertaking; which is dominant on both wholesale and retail levels.

- **Retail.** The price of electricity supplied to households and small customers entitled to universal service (0.4 kV) is still regulated. In its report of 2018, the regulator justifies the need for regulation based on energy poverty considerations and market poverty.

DSR development

- **Albania.** A framework to enable demand response and aggregators is missing. Article 15(8) of the EE Directive has not been transposed and the issue is not tackled under the EED progress report.[200] Measures outlined under the NEEAP[201] in relation to art. 15(8) appear insufficient. The regulator applies different tariffs at peak times; however, there is no proper implementation of time-varying electricity pricing; as the retail market remains highly regulated. There are certain plans for investments in smart grids[202] and deployment of smart metering;[203] as well as plans for developing net metering for solar generators.[204]

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198 Paragraph 3, Article 6, Rules for Purchase of Electricity for the Universal Supplier (Published on 14 September 2018 in “Official Gazette of the Republic of Macedonia No. 172/2018, as amended. Decision on approval of a model Agreement, adopted on 8 May 2019.

199 Tariff system for the sale of electricity by the universal service supplier and the supplier of last resort.

200 Albania, Second Progress Report under the EE Directive, March 2019.

201 See Second and Third NEEAP, Albania, p. 27-29, Section 2.4.2 on Article 15 EED.

202 The distribution operator OSHEE has announced, a call for tender “investments in the balance metering system (Bulletin Nr. 9 dated 04 Mars 2019, Public Procurement Agency); which was awarded to Networked Energy Services Corporation (NES) and ACI.

203 See Second and Third NEEAP, Albania, p. 27-29, Section 2.4.2. Art. 78 of the Energy Law enshrines the smart meter concept and requires from the distribution operator to carry out an economic assessment for its deployment. The latter has published a number of network modernisation plans.

204 A regulation for the connection to the grid to photovoltaic self-generators was adopted in June 2019 https://www.infrastruktura.gov.al/en/miratohet-udhezimi-per-lidhjen-ne-sistemin-e-shperndarjes-per-veteprodhuesit-fotovoltatik-

The electronic communications' regulator plans launching allocation procedure for 5G spectrum by 2020-2021.

- **Bosnia and Herzegovina.** There is no framework to enable demand response.[205] Demand side response was, in some cases, activated through ancillary services.

- **Kosovo*.** Articles 15(4) and 15(8) of the EE Directive have been transposed into primary legislation;[206] but the regulator has not yet adopted required secondary legislation to enable implementation. The DSR was not properly addressed under the NEEAP;[207] neither under EED progress reports.[208] Kosovo* authorities provide certain (limited) measures[209] to ensure that tariffs allow suppliers to improve consumer participation in system efficiency including demand response or that network tariffs support the development of demand response services as per art. 15(4);[210] but implement no further measures to comply with art. 15(8). Smart metering concept is enshrined in primary law;[211] but no significant investment has been made.

- **Montenegro.** There are no provisions in force that regulate the aggregators or the demand response. Article 15(8) of the EE Directive has not been transposed. This issue is only tackled under the Action plan of 2016-2020.[212] The TSO is obliged to establish by January 1, 2022, an advanced system for measuring electricity (smart meters), based on an economic assessment of all long-term costs and benefits.[213]

- **North Macedonia.** The available draft law on Energy Efficiency, transposes only partially Article 15 of the EE Directive.[214] This draft law (yet to be adopted) will also regulate

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205 See Market Rules from April 2015 https://www.nosbih.ba/en/korporativneAktivnosti/market-rules/105

206 Law No. 06/L-079 on Energy Efficiency, OG 21/2018,

207 Third NEEAP Kosovo*, 2017, Section 2.3.7.

208 Second Kosovo* EED Progress Report, 2018.

209 Third NEEAP Kosovo*, 2017, Section 2.3.7.

210 Administrative instruction no. 14/2012 on the promotion of energy end-use efficiency and energy services.

211 Art. 16, Law No. 06/L-079 on Energy Efficiency, OG 21/2018.

212 See Energy Efficiency Action Plan of Montenegro for 2016-2018 year

213 Energy law, article 247, paragraph 1; The Law was published in the "Official Gazette of Montenegro", no. 5/2016 and 51/2017 and entered into force on 28 January 2016.

214 Even though it is stated that the draft Law on Energy Efficiency transposes the Energy Efficiency Directive, it can be concluded that Article 15 is only partially transposed based on Articles 20, 21 and 22 of the draft Law on Energy Efficiency, https://ener.gov.mk/default.aspx?item=pub_regulation&subitem=view_reg_detail&itemid=tn62zOszAokY55g1O1tgyQ==

aggregators and smart meters. At the moment, demand response providers are excluded from participation due to lack of necessary framework. Pursuant to draft Law on Energy Efficiency, the regulator shall adopt tariffs and measures to enable the participation of the DSR. This draft may be subject to further changes during the adoption in the Assembly of Republic of North Macedonia.[215] Dynamic pricing is partially adopted in North Macedonia, only in the form of time-of-use pricing.[216] The Government has adopted National Operative Broadband Plan which analyses the requirements needed for implementation of 5G network.[217] The plan also defines the necessary steps for the development and efficient use of 5G.

- **Serbia.** There are no provisions in force that regulate the aggregators or the DSR providers. Article 15(8) of the EE Directive has not been transposed. However, there is ground for implementing different pricing schemes.[218] EPS applies certain demand response provisions in its contracts. Any operator that intends to act as DSR provider should obtain a supply license.

Planned reforms

D.4 Below we present the country-specific information on the planned reforms in the WB6 Contracting Parties with respect to:

- Climate change regulation;
- Organised market development; and

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215 Articles 21 and 22 of the draft Law on Energy Efficiency,

216 Pursuant to Article 14 of the Tariff system for the sale of electricity by the universal service supplier and the supplier of last resort, according to the time of delivery of the electricity during the day, the electricity prices will be determined as: (i) prices of electricity during the high peak demand; and (ii) prices of electricity during the off-high peak demand. Please refer to Article 14 of the Tariff system for the sale of electricity by the universal service supplier and the supplier of last resort (Published on 05 September 2018 in "Official Gazette of the Republic of Macedonia No. 164/2018, available at http://www.slvesnik.com.mk/Issues/9e0e30d80a1943b79c3ee8b27f74194b.pdf)

217 National Operative Broadband Plan, dated April 2019 http://www.mioa.gov.mk/sites/default/files/pbl_files/documents/reports/nacionalen_operativen_brodbend_plan_finalna_verzija_02.04.2019.pdf

218 Article 90 paragraph 3 of the Serbian Energy Law provides the possibility to purchase electricity on different prices depending on the various factors, such as setting the tariffs depending on the quality of energy delivered or generating products and takeover conditions including capacity, the annual, seasonal, monthly and daily dynamics of delivery, the category and group of customers, the point of takeover, consumption profile, the method of measurement, and other characteristics). Furthermore, the tariff system for the calculation of electricity for tariff costumers, published on the Official gazette of the Republic of Serbia, no. 1/2007, 31/2007, 50/2007, 81/2007, 21/2008, 109/2009, 100/2010 and 96/2011, sets different tariffs depending on the time and level of consumption.

- Phasing out price regulation.

Implementation of climate change regulation

- **Albania**. A draft climate law which provides for emissions' reporting and monitoring but no ETS provisions, has been prepared but not yet adopted. Moreover, Albanian authorities have not taken further steps on concrete ETS preparations such as the identification of installations or formulation of an MRV system.

- **Bosnia and Herzegovina.** Bosnia and Herzegovina is at very early stage, having developed lists of potential ETS installations and conducted some trainings and events. A legal framework is missing.

- **Kosovo*.** Kosovo* has taken no steps and seems to have no concrete plans.

- **Montenegro.** Montenegro is at very early stage, having developed lists of potential ETS installations and conducted some trainings and events. A legal framework is missing.

- **North Macedonia.** Ongoing cooperation projects with governments of Norway and Bulgaria for capacity building in EU ETS implementation; including identification of the future ETS participants, development of an action plan, organization of training activities etc.

- **Serbia.** A draft climate law has been prepared and is under discussion. It identifies implementation of ETS as well as regulations for monitoring and reporting of emissions and for third-party verification of emissions and accreditation of verification bodies. A pilot program has been operated. The Serbian authorities are preparing for accreditation of ETS verification bodies.

Organised markets development

- **Albania.** The enabling legislative framework has been adopted;[219] but the new market model is not yet operational. Based on the Government's Strategic Plan for the reform of the energy sector,[220] Albanian authorities planned to establish a functional day-ahead PX

219 Council of Ministers Decision No. 519 of 13 July 2016 on the Albanian Energy Market Model. According to Article 2 of the Market Model, "*any form of directly or indirectly regulated tariffs or prices, and any form of subsidies for different categories of customers, will be eliminated, with the exception of regulated tariffs, which are covered by the public service obligation, in accordance with the obligations of the Power Sector Law and the Energy Community Treaty*."

220 Council of Ministers' Decision No. 742, dated 12.12.2018 'On approval of strategic plan for the reform of the energy sector in Albania'

market by end September 2019.[221][222] This implies phasing out *acquis*-incompliant agreements between the state-owned generator KESH and public supplier OSHEE,[223] by amending accordingly the PSO act. KESH and OSHEE would be obliged to trade over the APEX a percentage (%) of volumes released from abandoning KESH-OSHEE's regulated contracts.[224] By 2019, KESH should offer about 25% of its volumes on the APEX.[225] This percentage should increase over the years until it reaches 80% in 2025. These measures should enhance liquidity on the APEX. The planned go-live date for the Albanian PX (i.e. end September 2019) and the phasing out of KESH-OSHEE PSO contracts has been subject to delay[226] and have not been implemented to date.

- In contraction with the Strategic Plan,[227] Albanian authorities are contemplating a potential merger between state-owned generator KESH and public supplier OSHEE. This might undermine the liquidity of the APEX and foreclose the national market.

- Based on the new Market Model,[228] relations and the role of market participants in the physical operation of the market model are determined by agreement between the individual participants and the APEX or they are regulated by bilateral applicable standard agreements.

  – The day-head pricing mechanism would be based on marginal pricing principle.

  – Price bidding caps in the DAM would range between 500 to 3000 EUR.[229]

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221 See Actions 5 of the Strategic plan for the reform of the energy sector in Albania' approved by the Council of Ministers' Decision No. 742, dated 12.12.2018.

222 See Actions 5 of the Strategic plan for the reform of the energy sector in Albania' approved by the Council of Ministers' Decision No. 742, dated 12.12.2018

223 In accordance with Annex 1 of the new Albanian Market Model, as adopted by Council of Ministers Decision No. 519 of 13 July 2016.

224 In accordance with Annex 1 of the new Albanian Market Model, as adopted by Council of Ministers Decision No. 519 of 13 July 2016.

225 In accordance with Annex 1 of the new Albanian Market Model, as adopted by Council of Ministers Decision No. 519 of 13 July 2016.

226 In May 2019, the Albanian Council of Ministers adopted a decision on the ownership structure the Albanian PX.

227 Council of Ministers' Decision No. 742, dated 12.12.2018 'On approval of strategic plan for the reform of the energy sector in Albania'

228 See Article 2 of the Council of Ministers Decision No. 519 of 13 July 2016

229 Albanian Market Rules approved by Decision 214/2017, which would enter into force upon the establishment of the Albanian power exchange, in particular, Addendum 2 on the Day-Ahead market.

– Maximum price bidding caps in the ID would be 10,000 EUR.[230]

– Participants may enter into financial contracts to hedge their position.

– At a second stage, an intra-day market would be established. A number of RES producers' PPAs would then be converted into Contract for Differences (CfD).

- **Bosnia and Herzegovina.** As a condition precedent to implementing the new market model, Bosnia and Herzegovina should adopt the State Law on Regulator, Transmission and Power Market and complimentary law at state level (i.e. Federation of Bosnia and Herzegovina and Republika Srpska), that transpose the Third Package. Absence of enabling primary legislation poses serious barrier to establishing the day-ahead market. Based on available information no concrete steps are being taken in this regard. At this stage, it is not possible to anticipate a deadline for the adoption of enabling primary legislation and establishment of organised electricity market in Bosnia and Herzegovina.

- **Kosovo*.** The enabling primary legislative framework has been adopted; but is not yet operational. The Ministers of Kosovo* and Albania have discussed the establishment of the common electricity market. Kosovo* has opted for organised electricity market serviced by the Albanian PX. The Kosovo transmission system operator KOSTT would be shareholder in the Albanian PX. A functional day-ahead PX for Kosovo* is dependent on APEX development in Albania.

- **Montenegro.** The enabling primary legislative framework has been adopted; but the new market model is not yet operational. The Government of Montenegro adopted in early November 2016 a plan for the establishment of Montenegrin power exchange (which was subsequently delayed). The shareholders are market operator COTEE, the Montenegrin transmission operator CGES and the national power utility EPCG, which on 21st of June 2017 an agreement for the establishment of the Montenegro power exchange, the power exchange's statute and registration of the company. BELEN, the company responsible for establishing a PX, and its selected strategic partner, Nordpool, are in the process of establishing the Montenegro PX ('MEPX'). The MEPX is expected to go-live in the first quarter of 2020.

- **North Macedonia.** The enabling primary legislative framework that provides for the new market model, has been adopted; but is not yet operational.[231] Licensing and

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230 Albanian Market Rules approved by Decision 214/2017, which would enter into force upon the establishment of the Albanian power exchange, in particular, Addendum 3 on the Intra-day market.

231 Article 90 of the Energy Law (Published on 28 May 2018 in "Official Gazette of the Republic of Macedonia No. 96/2018, as amended. Secondary legislation regulating PX is not yet adopted. There are a few provisions within the Electricity Market Rules (Published on 17 September 2018 in "Official Gazette of the Republic of Macedonia No. 173/2018, as amended, which envisage the existence of PX, and the Rulebook on the Manner and Procedure for Monitoring the Functioning of the Energy Markets (Published

operationalization of the PX operator are still pending. MEPSO, is the company responsible for establishing a PX; it has not yet selected strategic partners. There are reasonable doubts that the process could be further delayed. The model of the PX will be decided by the government, including the potential market coupling to the Independent Bulgarian Energy Exchange (IBEX) EAD.[232] The current Electricity Market Rules[233] only envisage the existence of PX, but do not regulate it in detail. The current framework does not provide for an obligation of certain operators to mandatorily trade over the PX. According to the Energy Law,[234] the regulator should approve the rules for operation of the PX, to be prepared by the PX operator in cooperation with the TSO (yet to be adopted). The current framework does not provide for the price caps for bidding in the PX (i.e. presumably, these will be defined in the PX rules). North Macedonia PX is expected to go live by end 2019 or early 2020.

- **Serbia.** The enabling primary legislative framework has been adopted; and is being implemented. The Serbian PX SEEPEX has been operating the day-ahead electricity market since February 2016, is expected to launch forward products by end 2019. Serbian authorities have no current plans to adopt measures to enhance liquidity over the SEEPEX. Regarding the intra-day market, SEEPEX did conduct a study which showed that there are still no sufficient conditions for the successful operation of an intraday market, as it is expected to be highly illiquid. In respect to price caps applicable under the new market model, there is a maximum price for the day-ahead segment for bids submitted to the SEEPEX at EUR 3,000.00 / MWh[235]

Phasing out price regulation

D.5 WB6 Contracting Parties may need to phase out price regulation that is not compliant with the Third Energy Package. However, most of WB6 Contracting Parties maintain regulated prices. As energy poverty and customers' vulnerability are key concerns that induce national authorities to keep energy prices below market-based levels in, WB6 Contracting Parties may need to combine phasing out of price regulation with targeted social measures to address vulnerability.

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on 08 July 2019 in "Official Gazette of the Republic of North Macedonia No. 138/2019, available at http://www.erc.org.mk/odluki/2019.07.04%20MM_Rulebook.pdf), which provides that the operator of the PX should file reports to the Energy Regulatory Commission necessary for monitoring the situation of the PX.

232 https://kapital.mk/sasho-vasilevski-mepso-zapochna-golema-investitsiska-ofanziva-investirame-150-milioni-evra-za-pokvalitetna-elektrichna-energija-2/

233 Electricity Market Rules (Published on 17 September 2018 in "Official Gazette of the Republic of Macedonia No. 173/2018, as amended

234 Article 24 of the Energy Law (Published on 28 May 2018 in "Official Gazette of the Republic of Macedonia No. 96/2018, as amended

235 See Article 1.3 of the SEEPEX Operational rules.

D.6 Country-specific plans include:

Albania

D.7 As provided by the new market model[236] and the Council of Ministers' Strategic Plan for the reform of energy sector[237] Albanian authorities plan:

- phasing out *acquis*-incompliant price regulation at wholesale level by abandoning the incompliant agreements between the state-owned generator KES and public supplier OSHEE[238] by end September 2019.[239] This also implies routing certain percentage (%) of volumes of the existing KESH-OSHEE regulated contracts on the APEX (*not functional yet*).[240]

- phasing out *acquis*-incompliant price regulation at retail level, for all end-customers with the exception of small customers and households 0.4 kV by September 2019. Albanian authorities plan to complement this reform with social measures to support vulnerable customers.[241]

- by September 2020, implement an upgraded, more transparent and non-discriminatory retail tariff scheme that ensures prices are market-based and account for due incentives for investment in capacity.[242]

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236 Council of Ministers Decision No. 519 of 13 July 2016 on the Albanian Energy Market Model. According to Article 2 of the Market Model, "any form of directly or indirectly regulated tariffs or prices, and any form of subsidies for different categories of customers, will be eliminated, with the exception of regulated tariffs, which are covered by the public service obligation, in accordance with the obligations of the Power Sector Law and the Energy Community Treaty." "(..) relations and the role of market participants in the physical operation of the market model, are determined by agreement between the individual participants and the Albanian Power Exchange (APEX) [yet to be established] and the TSO, or they are regulated by bilateral applicable standard agreements."

237 Council of Ministers' Decision No. 742, dated 12.12.2018 'On approval of strategic plan for the reform of the energy sector in Albania'

238 In accordance with Annex 1 of the new Albanian Market Model, as adopted by Council of Ministers Decision No. 519 of 13 July 2016.

239 See Element 9 of the Strategic plan for the reform of the energy sector in Albania' approved by the Council of Ministers' Decision No. 742, dated 12.12.2018

240 See relevant section above.

241 See Actions 9 of the Strategic plan for the reform of the energy sector in Albania' approved by the Council of Ministers' Decision No. 742, dated 12.12.2018.

242 See Element 12 of the Strategic plan for the reform of the energy sector in Albania' approved by the Council of Ministers' Decision No. 742, dated 12.12.2018.

Bosnia and Herzegovina

D.8 In *Republika Srpska,* according to plans of April 2019, wholesale price regulation between the incumbent generation companies to public suppliers should be phased out by the new Electricity Law, which provides for generation price deregulation.

D.9 In the Federation of Bosnia and Herzegovina and Republika Srpska,There are no further plans for: (i) phasing out unjustified price regulation at retail level (ii) ensuring that these regulated prices are set in way that allow for contestability by competitors.

*Kosovo**

D.10 We understand there are no further plans to phase out quasi-regulated prices for regulated volumes between the incumbent generation company KEK and the public supplier KEDS, at wholesale level. Moreover, as explained above, the Kosova e Re PPA sets a fixed pre-determined wholesale price for electricity and availability over a 20-years period, costs of which are expected to be passed on to end-customers. Kosovo authorities appear not to have plans to amend the Kosova e Re contractual framework.

D.11 Based on a decision of March 2019, Kosovo*s regulator plans to phase out unjustified price regulation for (i) 35kV customers by 31 March 2020, and (ii) 10 kV customers by 31 March 2021.

Montenegro

D.12 There seems not to be any plan for releasing to third parties portion of the wholesale volumes traded intra-group within units of the same undertaking EPCG, dominant on wholesale level and in monopoly position on retail level. There are also no plans to phase out unjustified regulation at retail level, or set retail prices at a level that is contestable by competitors.

North Macedonia

D.13 Starting 1 January 2019, ESM is obliged to offer a certain share of its production at market prices to the universal supplier, at non-regulated price. The Energy Law determines gradual reduction of this share (i.e. 80% in 2019, up to minimum 30% in 2025).

D.14 To the best of our knowledge, there are no plans for changing the tariff system for the sale of electricity by the universal service supplier and the supplier of last resort.[243]

Serbia

D.15 To the best of our knowledge, there are no plans to release on the wholesale market volumes traded intra-group within units of the incumbent EPCG, dominant on both wholesale and retail levels.

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243 Tariff system for the sale of electricity by the universal service supplier and the supplier of last resort.

D.16 In its report of 2018, the regulator justifies the need to maintain retail price regulation for households and small customers based on energy poverty considerations.[244] It has no plans to phase out retail price regulation or set regulated prices at a level that is contestable by competitors.

[244] See AERS Report on 2018, on need to regulate retail prices.

Appendix E

Potential Existing State Aid in WB6 Contracting Parties

Introduction

E.1 This appendix written by DLA Piper presents a summary of the potential existing state aid in WB6 Contracting Parties electricity sector, distinguishing between the measures that impact the revenues of generating capacity in the Energy Only markets and the measures aimed at supporting investment in new capacity or in the refurbishment of existing capacity.

Potential existing State aid in WB6 Contracting Parties

Table 23: Summary of potential existing State aid in WB6 Contracting Parties that affect functioning of Energy Only markets

Country	Fiscal support	Public finance support	SOE support	Indirect subsidies
Albania	Debt write-off to OSHEE Tax concessions and debt prolongation or partial write-off to KESH in 2012-2017 Advances to OSHEE to cover debt collection risk	State guarantee and refinancing of existing overdrafts to KESH (through EBRD Loan - 218m EUR) State security in supporting KESH's contracts 2012-2017	Delayed payments by OSHEE to tenders' winners with no late interest	
Bosnia and Herzegovina	Tax concessions and contributions in arrears - coal mines Tax advantage in VAT in arrears - coal mines		Reduction of fees for the use of natural resources for electricity production Short-term loans for coal mines by EPBiH Interest free advance payment to coal mines by EPBiH	Operation of incumbent at low or negative level of profitability
Kosovo*	Government Loan to KEK Direct budget transfer to KEK for support in operational costs Foregone interest on government loan to KEK			
Montenegro	Tax concessions and waiver of arrears in RU Pljevlja coal mine		Waiver of debt collection by EPCG from RU Pljevlja coal mine	
North Macedonia				
Serbia	Tax concessions and waiver in arrears in underground coal mines to RU Resavica Partial write-off of government debts (outstanding from SFRY - SSSR, Serbia and Russian Federation) to EPS Government loan to PEU Resavica coal mine			

Table 24: Summary of the potential existing State aid in WB6 Contracting Parties for investment in new or refurbished capacity

Country	Fiscal support	Public finance support	PPA	SOE investment support
Albania		State Loan (with EBRD) on the rehabilitation of Koman HPP Pass-through of costs for the refurbishment of the TPP Vlora in regulated retail tariffs	Large hydro (HPP Ashta) Large solar (50 MW)	
Bosnia and Herzegovina		State Guarantee - construction of Tuzla TPP B7 (EBBiH) State Loan from Japanese government - Ugljevik TPP desulphurization (ERS) State Loan (Podveležje wind farm) (EPBiH) Intergovernmental support for HPP Buk Bijela, Foča and Paunci (EPS and ERS)		Investment in coal mines capital base by EPBiH
Kosovo*	VAT exemption Kosova a Re	State Guarantee and other advantages (Kosova e Re – Contour Global) State Guarantee for refurbishments under WB IDA (KEK)	Kosova e Re	
Montenegro		State Guarantee for refurbishment in TPP Pljevlja - KfW Loan (EPCG) State Guarantee - HPP Perućica Revitalization (EPCG)	RE	
North Macedonia		State Guarantee - refurbishments in TPP Bitola 1, 2, and 3 - Deutsche Bank Loans (AD ESM) State Guarantee – refurbishments and upgrade in TPP Bitola - Stopanksa Bank Loan (AD ESM) State Guarantee - construction of Geotino 3- Deutsche Bank Loan (AD ESM)	RE	
Serbia	Direct budget transfer for expenditure in underground coal mines (RU Resavica) Direct budget transfer for refurbishment in Nikola Tesla TPP (EPS)	State Loan (JICA/ODA) and State Guarantee – refurbishments in Nikola Tesla TPP (EPS) KfW State loan and state guarantee - refurbishments in Nikola Tesla TPP Nikola Tesla (EPS) State loan (KfW) and state guarantee Kolubara B and C refurbishment (EPS) State Guarantee - refurbishments in Kolubara project A - EBRD Loan (EPS)) State Loan (China Exim Bank) and state guarantee – refurbishments in Kostolac B1 and B2 and construction B3 (EPS)	Large-scale HPP and wind	

Notes: *This list of support measures that might constitute state aid is only indicative; and not exhaustive. The Consultant has not made an in-depth assessment of these measures. This list serves only as guidance to understand current investment incentives in the WB6 Contracting Parties.*

Source: *Energy Community Secretariat Study on Analysis of Direct and Selected Hidden Subsidies to Coal Electricity Production in the Energy Community Contracting Parties;*

WB6 Contracting Parties' Official Gazettes,
WB6 Contracting Parties' Strategy Documents and Security of Supply Statements,
Audited Accounts of beneficiaries and contracts publicly available.

Publicly available contracts

- **Albania.** Current investment in generation capacity or restructuring of incumbents' accumulated debt is highly dependent on state support.[245] Albanian authorities primarily subsidise the incumbent generator KESH and the public supplier FSHU through state guarantees, state loans, direct advances, certain tax concessions or delayed payments. They also subsidise renewables primarily through FiT PPAs.[246] Plans on the restructuring of the energy sector are expected to involve additional state aid.

  – **KESH Vlora TPP refurbishment and gas-conversion project KESH.** The Council of Ministers Decision 244 'On public support obligations', as amended determine that investment costs for the refurbishment and gas conversion of Vlora TPP would be passed through to end-users *via* universal supplier FSHU's regulated retail prices. In the view of KESH's financial position, this project is expected to involve additional state support.

- **Bosnia and Herzegovina**. Current investment in construction or refurbishment of generation capacity is highly dependent on state support. State primarily support the incumbents, through state guarantees, state loans, certain tax concessions, when they need to raise financing for capacity construction or refurbishment works. State also support coal mines through direct advances or state-owned enterprises (SOE) investment. State support investment in renewables primarily by means of FiT PPAs. Below we list a number of projects for construction or refurbishment in generation capacity, which are meant *inter alia* to contribute to secure supplies and generation adequacy.[247]

  – **EPBiH Tuzla Thermal Power Plant construction of the new Block 7, with the capacity of 450 MW**. The Project is financed by a loan from the Export–Import Bank of China (Chexim – China Exim Bank, of approx. EUR 614 million) to EPBiH. The Federation of Bosnia and Herzegovina has granted a state guarantee. Such despite state guarantee was granted despite an opened infringement procedure by the Energy Community Secretariat and an independent report outlining state aid elements.

  – **HPP Buk Bijela, Foča and Paunci.** These projects are to be built jointly by Serbian EPS and Republika Srpska ERS through inter-governmental support.

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245 In strategy documents and Security of Supply Statements, including without limitation, Albania Council of Ministers Decision No. 742, dated 12.12.2018 'On approval of the strategic plan for the reform of the energy sector'.

246 Only two large HPPs operate on the basis of 35-years concession contracts with no PPA.

247 Framework Energy Strategy of Bosnia and Herzegovina until 2035; Kosovo* Security of Supply Statement, 2017; EPBiH's publicly available information on planned investments.

– **ERS Ugljevik Thermal Power Plan refurbishment for desulphurization**. The project is financed by loan from the Japanese Government. A public guarantee covers the repayment of this loan.

- **Kosovo.** Current investment in construction or in refurbishment of generation capacity is highly dependent on state support. The State primarily subsidises the incumbent KEK, through state guarantees, state loans tax concessions, direct budget transfers. The State plans to also subsidise the private investor Contour Global for the Kosova e Re Project. Below we list a number of key projects for construction or refurbishment in generation capacity, which are meant *inter alia* to contribute to secure supplies of electricity and generation adequacy.[248]

  – **Kosova a Re coal fired power plant (450MW) project.**[249] This major planned investment relies on a PPA between Government of Kosovo*, whose rights are assigned to its 100% subsidiary NKEC, and Contour Global. This PPA and other inter-related agreements guarantee to Contour Global, fixed electricity and availability price over 20 years period as well as other advantages. This seems to ensure to the investor pre-determined guaranteed return on investment, covering investment and operating costs.[250] The Government of Kosovo* and the energy regulator have

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248 Kosovo*, Security of Supply Statement, 2017, available at: https://www.energy-community.org/dam/jcr:bd6186ff-8369-44fe-88a3-0523ddd80d89/2017_SOS_KO.pdf; Kosovo* Energy Strategy 2017-2026; Kosovo* Energy Strategy Implementation Program 2018-2020.

249 Kosova e Re's project agreements are publicly available at: https://mzhe-ks.net/en/commercial-contracts-of-tc--kosova-e-re--project#.XkHew2hKg2w.

250 The Kosova e Re Contractual Framework consists of 8 agreements : (i) Power Purchase Agreement (PPA) concluded between Kosovo* (through the Ministry of Economic Development) and Contour Global (ii) Implementation Agreement (IA) concluded between Kosovo* and Contour Global; (iii) Sponsor Support Agreement (iv) Site Transfer Agreement concluded between KEK and Contour Global; (v) Ash and Gypsum Disposal Agreement concluded between KEK Mining and Contour Global; (vi) Lignite Supply Agreement concluded between KEK Mining and Contour Global; (vii) Connection Agreement concluded between KOSTT and Contour Global; (viii) Water Supply Agreement.

Based on the PPA between Government of Kosovo* (whose rights are assigned to its 100% subsidiary NKEC) and Contour Global, Contour Global is guaranteed over 20 years period: (i) mandatory purchase by Offtaker of generated electricity at a pre-set electricity price that covers variable costs (fuel, etc.) and O&M; (ii) payment for capacity availability up to 470 MW at a availability payment that covers investment costs and nominal equity rate of return of 20%; the PPA price at 80 €/MWh; can be increased to ensure pre-determined guaranteed return on investment; exemption from balancing responsibility and ancillary services; exemption from transmission charges, and system/market operation charges; reimbursement a number of environmental costs incurred due to compliance with acquis on environment. Based on maintained that recourse to a PPA is the only financially affordable solution for Kosovo* to attract private sector investment for the construction of generation capacity to satisfy the country's long-term environmental and security of supply objectives.[251]

  - **Flexible HPP (200 MW) construction project**. This project is planned to provide balancing and optimizing power system use.[252] Its implementation is expected to involve additional state support.

- **Montenegro.** Current investment in construction or refurbishment of generation capacity is highly dependent on state support. Authorities primarily subsidise the incumbent through state guarantees that secure loan obligations. State also support coal mines through tax concessions or debt writte-off. In the Strategy Document,[253] Montenegro identifies measures to guarantee security of supply in the long term. These primarily include investment in constructing new capacity or refurbishing existing capacity to meet environmental requirements. Below are presented details for some of the key investments.

  - **EPCG project on environmental rehabilitation of Pljevlja TPP (EUR 60 million).** This project is expected to be supported through state guarantee. It should be completed by 2021.

  - **EPCG refurbishment and upgrade of HPP Piva (342 MW) and HPP Perućica (307 MW).** This project is supported through a state guarantee, adopted by law in January 2019, which secure EPCG's loan obligations up to EUR 33 million.

- **North Macedonia.** Current investment in construction or refurbishment of generation capacity is highly dependent on state support. Authorities subsidise primarily the incumbent ESM through state guarantees. They also support investment in renewables through FiT PPAs or recently feed-in premiums. Availability of coal for the Bitola thermal

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other agreements, Contour Global is granted by the Kosovo* State additional advantages or subsidies such as: reimbursement of take or pay payments to KEK mining for lignite supply; exemption from VAT and tax reliefs for construction and development activities; transfer of properties at symbolic prices; state guarantee that irrevocably and unconditionally guarantees performance of all terms, conditions and covenants and the full and prompt payment of any amounts due by all publicly owned enterprises under any of the project agreements. To ensure resale of electricity purchased from Contour Global and pass-through of costs to end-users, Offtaker shall enter into a PPA with public supplier (KESCO).

251 See Recitals in the Power Purchase Agreement, available at: https://mzhe-ks.net/en/commercial-contracts-of-tc--kosova-e-re--project#.XkHew2hKg2w.

252 Planned in 2023.

253 Montenegro, Energy Development Strategy by 2030, including action plan 2016-2020.

power plant needs to be urgently addressed and call for resource diversification.[254] In the strategy document,[255] North Macedonia identifies measures to ensure security of supply in the long term. These primarily comprise investment in constructing new capacity or refurbishing existing capacity to meet environmental requirements. Below are presented details of some of the key planned investments in generation capacity.[256]

– **ESM Modernization of TPP Bitola project.** This Project is financed by loan agreement concluded between ESM and Deutsche Bank (EUR 49 million), which full repayment by ESM is secured through state guarantee issued in favour of Deutsche Bank.

– **Environmental refurbishment of the TPP Bitola.** ESM plans to invest further in the environmental refurbishment of the TPP Bitola (estimated approx. EUR 140 million), which investment is expected to involve additional state support.

– **ESM modernization of the existing mines**. These planned investments (estimated approx. EUR 41 million) are expected to involve additional state support.

– **New coal-field opening**. This investment estimated at EUR 122,5 million is expected to involve additional state support.

– **Oslomej TPP gas-conversion and refurbishment.** Oslomej TPP is meant to address issues with coal delivery and technological obsolescence. This planned investment by ESM estimated at around EUR 45 million is expected to involve additional state support.

- **Serbia.** Current investment in construction or in refurbishment of generation capacity is highly dependent on state support. State authorities primarily subsidise the incumbent EPS, through state guarantees, state loans, certain tax concessions, budget transfers, debt write-off. State also subsidises coal mines through direct advances, tax concessions or state-owned enterprises (SOE) investment. Serbian authorities support renewables, including large-scale renewable projects[257] through FiTs PPAs awarded to those acquiring

254 EU Progress Report on North Macedonia, 2019, p. 74.

255 See North Macedonia, Strategy for the energy development until 2030; North Macedonia; Security of Supply Statement, 2019, available at: https://www.energy-community.org/dam/jcr:86a92591-222c-4a85-b15e-cdf25e8176a5/SoS_MA_%202019.pdf

256 North Macedonia, Security of Supply Statement, 2019, available at: https://www.energy-community.org/dam/jcr:86a92591-222c-4a85-b15e-cdf25e8176a5/SoS_MA_%202019.pdf

257 The maximum capacity for acquiring the status of a privileged producer or a preliminary privileged producer is (i) 500 MW for wind power plants, (ii) 2MW to 6 MW for solar powered capacities, (iii) 30 MW for

the status of a privileged producer.[258] In the Strategy Document, related Implementation Program and Security of Supply Statement[259] Republic of Serbia identifies measures to ensure security of supply in the long-term, which primarily comprise investment in constructing new capacity or refurbishing existing capacity to meet environmental requirements or extend lifespan of existing capacity. In this category Serbian authorities also list projects in renewable energy capacity.[260] These projects would contribute in replacing volumes from planned phasing out of existing capacities due to environmental requirements.[261] Republic of Serbia typically supports financing for these construction or refurbishment projects through state guarantees or state loans. These projects are considered investments of great importance for reliable and secure energy supplies in the Republic of Serbia.[262] It also grants to the state-owned incumbent EPS or its subsidiaries other forms of state support which may result in lower operational or financing costs.

Below we present details for some of these projects for construction or refurbishment of generation capacity in the Republic of Serbia.

– **EPS Kostolac B refurbishment of existing blocks B1 and B2 and construction of the new block Kostolac B3** (350MW).[263] This project is financed (85%) by a loan between the Government of the Republic of Serbia and the China Exim Bank, of a

hydroelectric power plants, (iv) Biomass power plants, (v) Biogas power plants, (vi) Power plants using landfill gas and gas from communal waste water treatment facilities, (vii) Geothermal power plants, and (viii) Waste-to-energy plants.

258 Privileged producers are awarded PPAs with incentive price administratively determined by the regulator, for a 12-years period from commercial operation date, as well as exemption from balancing responsibility and payment of network use charges.

259 Republic of Serbia, Security of Supply Statement, 2018, available at: https://www.energy-community.org/dam/jcr:771eacfe-95d2-4b28-850a-c0a6ab99e3eb/SoS_Serbia_2018.pdf; Republic of Serbia Energy Sector Development Strategy for the period by 2025, with projections up to 2030; Republic of Serbia Decree on the Implementation program for of the energy sector development strategy for the period to 2025, with projections up to 2030.

260 In particular, Republic of Serbia states various planned projects on wind farms with total installed capacity up to 500 MW (i.e. Alibunar, Malibunar, Plandište 1, Kovačica, Čibuk 1, Kosava and Kostolac). These are to be supported through FiT. It seems most of them have already acquired the temporary status of privileged producers. See Security of Supply Statement, Serbia, 2018, page 46.

261 Program for the implementation of Energy Strategy. According to Serbian authorities these projects are expected to increase total estimated electricity generation by 4,427 GWh.

262 See Security of Supply Statement, Serbia, 2018, page 46.

263 Serbia, Security of Supply Statement 2018, para. 3.7.1., and para. 4.10, Implementation Action Plan 2017-2023 Republic of Serbia, p. 20-21.

duration of 20 years, which grants preferential conditions and secured through by government guarantee and by EPS's own funds (15%).[264] EPS signed the construction contract with the Chinese corporation China Machinery Engineering Corporation (CMEC) for the (i) first phase consisting in refurbishment of existing blocks B1 and B2 (refurbishment works estimated at USD 334.63 million and construction of desulphurization system at USD 130.5 million),[265] (ii) the second phase consisting in the construction of a new block B3 with installed capacity of 350 MW and the expansion of the Drmno open cast mine (construction works estimated at approx. USD 715.6 million).[266]

– **EPS Nikola Tesla TPP construction of desulphurization plant.** The project is implemented under an agreement between the governments of Republic of Serbia and Japan, based on which EPS signed a loan agreement with the Japan International Cooperation Agency (JICA) in 2011 (approx. EUR 167 million). A State Guarantee (2011) was issued to secure repayment by EPS of its obligations under JICA Loan Agreement. Following the above, EPS and JICA selected the consortium for the implementation of the project, namely the Japanese corporation ITOC HU, Mitsubishi Hitachi Power System Europe and company MPP Jedinstvo from Sevojno.[267]

– **EPS Nikola Tesla TPP refurbishment**. This project is implemented with funds from the German development bank KfW (approx. EUR 45 million), which is secured through a state guarantee in favor of the KfW. This guarantees full repayment of the loan by EPS.

– **EPS Kolubara refurbishment**. This project is implemented with funds from the German development bank KfW (EUR 65 million) and grants (EUR 9 million). State guarantee secures full repayment of the loan to KfW by EPS.

– **EPS Kostolac wind farm** (66MW). This capacity would be under ownership of the state-owned EPS. The Project is financed by a loan between EPS and the German development bank KfW, signed in November 2017 (approx. EUR 80 million), which full repayment by EPS is secured by a state guarantee, issued in April 2018. This state guarantee apears to unconditionally secure for total potential debts and not to comprise a premium. EPS is eligible to get incentives under the FiT scheme for Kostolac, if it applies for temporary privileged producer status before the relevant RE

264 See Security of Supply Statement, Serbia, 2018, para. 4.10., page 46 and 51.

265 See Security of Supply Statement, Serbia, 2018, para. 4.10.

266 See Security of Supply Statement, Serbia, 2018, para. 4.10., page 46.

267 See Security of Supply Statement, Serbia, 2018, page 47.

FiT decree expires. From publicly available information, it seems however no such PPA has been awarded yet.

– **Čibuk 1 Wind farm** (158 MW). This plant is privately-owned by Tesla Wind, a joint venture between Masdar (60%), Finnish energy infrastructure developer Taaleri Energia (30%), and DEG, a subsidiary of Germany's KfW Group (10%). This is an investment estimated at EUR 300 million. The PPA for this project was signed in October 2016. This implies a PPA with an administratively set incentive price, for a 12-years period from commercial operation date, exemption from balancing responsibility and from payment of network use charges.