The Integrated Electricity Markets in Greece and SE Europe, the Role of the International Electricity Interconnections and the Impact on Industry

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This Working Paper outlines the Executive Summary of IENE's Study on the "The Integrated Electricity Markets in Greece and SE Europe, the Role of the International Electricity Interconnections and the Impact on Industry" (IENE Study M54), which was completed in April 2020.

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Executive Summary

Raison d'être

The present Working Paper addresses the future of electricity market in Greece and in SE Europe following latest developments by making a projection of the operation of the electricity market at a regional level. An extensive record of current and anticipated changes in the organizational framework of the regional electricity markets and electricity system infrastructures of Greece, Albania, Bulgaria, Romania, Serbia, Kosovo, Montenegro, Bosnia and Herzegovina and North Macedonia is presented. This is followed by a comprehensive modeling simulation of the performance of the regional Electricity Market of SE Europe that provides a glimpse of all aspects of the operation of the regional electricity market, as well as the volume of cross border electricity trade and electricity prices for all regional consumers at wholesale and retail level for the period 2020 - 2030. In short, the present Working Paper constitutes a useful tool in assessing future electricity market performance in the SEE region under a certain set of parameters.

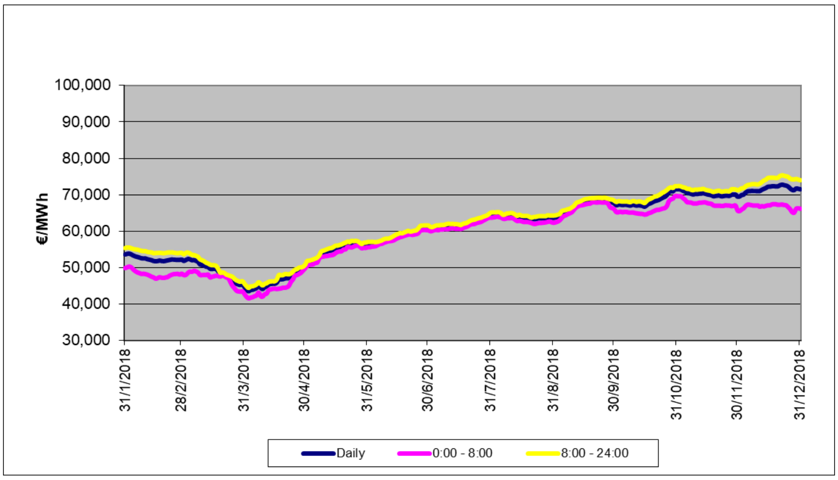
Current and Future Electricity Market Design in Greece

Mandatory Pool: Currently, Greece's wholesale electricity market operates under Day Ahead Scheduling (DAS) or the "mandatory pool", through which all electricity produced domestically, at the country's interconnected electricity system (excluding non-interconnected islands), is being traded. The mandatory pool operates as a complex algorithmic procedure, minimizing the operational costs of generating units, under unit commitment and system constraints. Participation in the mandatory pool is compulsory and producers are required to bid for the total amount of their available capacity, while suppliers are obliged to bid for the entirety of their demand. Hence, bilateral physical delivery contracts between producers and suppliers/consumers are not currently allowed. The DAS model operates in two frameworks, the Day Ahead Market (DAM) and Day Ahead Ancillary Services Market (DAASM), where wholesale electricity trade and reserves and ancillary services are assured respectively. Moreover, a specific market mechanism, "The Imbalance Settlement Mechanism", is responsible for the compensation of ancillary service provision and generation deviation charges. In addition, "Transitional Flexibility Remuneration Mechanism" is deployed in order to remunerate producers for their availability to provide flexibility services to the TSO. Furthermore "Variable Cost Recovery Mechanism" is in place to give the ability to producers to recover their variable cost in cases, when a specific unit is dispatched either without being scheduled on DAS or acting as a spinning reserve for balancing purposes.

The System Marginal Price (SMP) is the price at which the DAM is cleared, that is, the price charged by all those who inject energy into the Interconnected System, and which is paid by all those who request energy from the Interconnected System. The SMP is simply an equilibrium price, resembling the highest accepted bid, by the most "expensive" unit, dispatched at a certain period of time, while all producers who had successful bids at lower prices are remunerated at the SMP. SMP is computed by the Energy Exchange, HEnEX S.A., while IPTO (ADMIE) conducts the forecast for electricity demand and cross-zonal transmission system constraints. Zonal pricing is not applicable, but explicitly derived two zonal prices serve as an indication of congestion. The energy offers in DAM are limited by a (a) Minimum variable cost threshold for placing bids in the DAM, which is technology/source specific, and an (b) opportunity cost of hydro power plants for pricing hydro generation, which is defined by the regulator by a specific methodology taking into account water availability and savings of variable cost in thermal power generating systems. Additionally, there is an administratively defined maximum value (price cap) for energy offers and primary and secondary reserves' offers defined by the regulator.

In 2016 the Greek Regulatory Authority for Energy (RAE) introduced a scheme of "Regulated Auctions for Forward Baseload Electricity Products" in the Greek electricity market. This mechanism, known as "**NOME auctions**" and foreseen by the L. 4389/2016, as amended, aimed at reducing the share of the incumbent electricity producer and supplier in the Greek wholesale and retail energy markets. The "auction products" refer to baseload energy that is provided by the incumbent to the independent retail suppliers. The products are virtual, in the sense that they are not produced by specific generation facilities and their delivery does not depend on actual electricity plant operation. The volume of products to be auctioned is linked to an equivalent decline of the incumbent's retail market share per year until 2020.

Figure 1: Monthly Rolling Average SMP, Daily and Individual Intra-Day Intervals, 2018



The Market Initiative: The development of a single European electricity market by 2014 was a major theme of the Third Package of European energy legislation, which came into force in March 2011. The rules for market integration as incorporated in the European Target Model for electricity are designed to facilitate the efficient transfer of electricity across Europe and to deliver electricity supplies that are: (i) secure, as a bigger market should provide greater diversity in generation and demand; (ii) low-carbon through facilitating the high integration of renewables to meet 2020 targets and beyond; and (iii) affordable by allowing more efficient use of resources, both networks and generation, and encouraging greater competition in electricity markets. The Target Model is designed to provide a single market rather a single price across Europe in all periods. However, the initiative should deliver greater (if incomplete) price convergence than the current arrangements.

At the heart of the Target Model is the concept of **price coupling**, both at the Day Ahead and intraday frameworks. Price coupling is a form of implicit auction, which means that available interconnection capacity and energy flows are effectively traded together, as opposed to an explicit auction used for long-term rights in which interconnection capacity is sold as a separate product from energy flows.

The restructuring of the Greek **Day-Ahead Market** is imposed under the CACM Regulation, which establishes guidelines on capacity allocation and congestion management and sets the requirements for the formation of a single internal day-ahead electricity market in Europe that will be cleared by a common price coupling market clearing algorithm. CACM regulation on the DAM framework outlines the electricity market architecture that needs to be in place to allow implicit Day-Ahead Market auctions to take place. Cross border electricity trade is designed to take place as a result of implicit allocation of Cross Zonal Capacities through Market Coupling, implemented through the pan-European Day-Ahead Market coupling algorithm, EUPHEMIA. The internal procedures and the standard corporate governance of the Multi-Regional Coupling (MRC) project shall be applied also in Greece. Nevertheless, there will be a certain transitory period, in which only the Market Coupling with the Italian Borders shall be activated, whereas daily explicit auctions for the allocation of daily PTRs shall continue to be implemented for the Greek northern interconnections.

The creation of an **Intra-Day Market** is also mandatory in the CACM Regulation, which sets out the requirements for the formation of a single internal Intra-Day Market in Europe. This market is designed to have harmonized rules, procedures and timing, tradable products and maximum/minimum prices. Intra-Day Markets allow Participants to update their trading position based on their risk profile taking into account evolving market and system conditions as we approach real time. The Target model incorporates IDM as either auctions or continuous trading scheme, which is the preferable option. In order for IDM to work a continuous trading matching algorithm determines selected orders, such as the matchings (a) maximize economic surplus for single intraday coupling per trade for the intraday market time-frame, (b) respects the allocation constraints, (c) respects the cross-zonal capacity restrictions, (d) respects the requirements for the delivery of results set out in Article 60 of CACM regulation, (e) the matching procedure is repeatable and scalable.

As a Member State, Greece is obligated to fully comply with the European regulations and proceed with the creation of an Intra-Day Market and its coupling with the other European Intra-Day Markets, since such reform will lead to the maximization of the overall European social welfare through the efficient utilization of the scarce interconnection capacity and the effective allocation of the pan-European resources. The Greek Intra-Day Market should be designed in such way in order to take into consideration intra-day cross-border operations in the Italian Borders (Central South European region), the special market and financial conditions in Greece and the status of the local electricity markets in the Greek northern borders (Bulgaria, FYROM, Albania and Turkey)

As the fundamental design architecture of the internal (national) European **Balancing and Ancillary Services Market** has already been defined, this is expected to be adopted by all Member States (thus also Greece), as a starting point to facilitate further integration in the future. In accordance to Entso-e’s Network Code on Electricity Balancing, the Balancing and Ancillary services market can be defined as a transparent market architecture model that includes all the actions and activities performed by a TSO to ensure the continuous real-time Balancing of electricity demand and supply in the respective power system. In the specific framework market participants should be incentivized to reduce their imbalances and to maintain available balancing resources and reserves to restore system balance at all times.

The development of Greek electricity **Forward Market** is not an obligation stemming from the European institutional framework, as opposed to the development of the three above-mentioned markets. Forward Markets are deployed in order to increase efficiency of the electricity market by mitigating risks, balancing market power and secure long-term investment decisions.

Target Model: In order for Greece to adopt the Target Model the Greek State must implement significant energy reforms, including the adaption of the Greek electricity market to EU Regulation 2015/1222 (CACM) and EU Regulation 2016/1719 (FCA). Consequently, the Greek Parliament voted the “Target Model law for the Hellenic

State” (L. 4425/2016) which provides the general framework for the implementation of the Target Model in the Greek wholesale market. The Greek authorities envisage the creation of a Forward Market with forward contracts on electricity, both Over-The-Counter (OTC) and centrally-traded (organized Forward Market), a reformed, energy only Day Ahead Market, an Intra-day Market, which is a fundamental aspect of the EU Target Model, as well as a Balancing Market.

DAM: The participation in the Day-Ahead Market is mandatory only for the Producers who shall participate on a unit-basis. Participation is optional for RES Producers who can participate either on a unit-basis (per RES Unit) or on a portfolio-basis but only for their own RES Units; RES Aggregators may participate on a portfolio basis per RES category and Load Representatives may participate on portfolio-basis for their whole portfolio. The Greek Day-Ahead Market shall include two types of Orders (Simple and Block Orders), in order to increase the Producers’ options to optimize their assets. Moreover, the Producers are obligated to offer the remaining of the total production availability of the conventional Generating Units they represent in the Day-Ahead Market, in order to ensure the liquidity of the Day-Ahead Market and prevent physical withholding (semi-compulsory wholesale market).

IDM: The IDM will be deployed in two phases. The 1st phase will include three Local Intra-Day Auctions (LIDAs) implemented within Greece, while in the 2nd phase Greek IDM will adjust to implement pan-European Continuous Intra-Day Trading through the already agreed ID Solution, in combination with one Local Intra-Day Auction (LIDA) and two Complementary Regional Intra-Day Auctions (CRIDAS). The participation of Producers in the Intra-Day Market is on a unit-basis. RES Producers, RES Aggregators and the Last Resort RES Aggregator participate for each Dispatchable and Non-Dispatchable RES Portfolio and Load Representatives participate for each Dispatchable and Non-Dispatchable Load Portfolio.

BM: The operation of the Balancing Market will be based on the unit based central dispatching model. In this context there will take place the execution of a unit commitment model at the day-ahead timeframe (day D-1), followed by a number of respective executions repeated successively in the intraday stage. The first phase is the scheduling phase referred to as the Integrated Scheduling Process (ISP). The ISP model is formulated as a co-optimization problem of Balancing Energy and the various types of Reserve Capacity.

Capacity Remuneration Mechanisms, Options and Implications: Capacity mechanisms are measures that offer additional rewards to capacity providers in return for maintaining existing capacity or investing in new installations to generate electricity amidst adequacy concerns. Capacity mechanisms have an impact on competition in the internal electricity market. Many of these mechanisms will qualify as state aids in the meaning of Article 107(1) TFEU, and will be subject to EU State aid rules. Consequently, EU Commission's position stands on the proposition that an energy-only 'Target Model' would be sufficient to deliver reliability, without the need for separate arrangements to ensure adequate capacity was available. Moreover, this position supports the idea that peak load generators would attain market value for their production above their short run marginal costs (SRMC), offering their products at "scarcity prices" given the low elasticity of electricity demand, which is the main concern when addressing the missing money problem for peak load generators. Moreover, in order for Energy only Markets (EOMs) to work in the long run, price spikes in the electricity market should be sufficiently high in order to stimulate investment. However, as very high prices are not socially acceptable many regulators (i.e. in Germany, Belgium etc.) have deployed de facto price caps in electricity markets. Other capacity mechanisms currently deployed in Europe and elsewhere include capacity, payments, strategic reserves, capacity obligations, reliability options etc.

Electricity Interconnections in Greece and SE Europe

In its first report "Towards a sustainable and integrated Europe" published in November 2017, the Commission Expert Group on electricity interconnection targets, concluded that the socio-economic value of electricity interconnectors stems from: (a) their ability provide lower electricity prices to consumers with the integration of European markets, (b) enabling accommodation of the increasing production levels of RES units, (c) increase security of supply, (d) strengthen regional cooperation between Member States and (e) the fact that they offer opportunities for uptake of European technologies and thus strengthen employment, industrial competitiveness and global leadership of Europe's clean, low-carbon industries

Existing Interconnections: Net Transfer Capacity (NTC) as well as the Thermal Capacity of each one of the existing interconnectors in SEE region for the year 2018 are presented in the following table.

Table 1: NTC & Thermal Capacity of Interconnections in 2018

Country 1	Country 2	NTC (MW)	Thermal Capacity (MW)
ALBANIA	**KOSOVO**	**550**	**1548**
ALBANIA	**MONTENEGRO**	**500**	**1548**
ALBANIA	**GREECE**	**250**	**1278**
BOSNIA_HERZEGOVINA	**MONTENEGRO**	**500**	**1953**
BOSNIA_HERZEGOVINA	**SERBIA**	**600**	**1418**
BULGARIA	**NORTH_MACEDONIA**	**250**	**1330**
BULGARIA	**SERBIA**	**300**	**1500**
BULGARIA	**GREECE**	**500**	**1170**
BULGARIA	**ROMANIA**	**300**	**5313**
KOSOVO	**ALBANIA**	**500**	**1548**
KOSOVO	**MONTENEGRO**	**250**	**1184**
KOSOVO	**SERBIA**	**500**	**1438**
KOSOVO	**NORTH_MACEDONIA**	**500**	**1330**
NORTH_MACEDONIA	**BULGARIA**	**250**	**1330**
NORTH_MACEDONIA	**SERBIA**	**425**	**1300**
NORTH_MACEDONIA	**GREECE**	**200**	**2660**
NORTH_MACEDONIA	**KOSOVO**	**500**	**1330**
MONTENEGRO	**ALBANIA**	**500**	**1548**
MONTENEGRO	**BOSNIA_HERZEGOVINA**	**500**	**1953**
MONTENEGRO	**KOSOVO**	**250**	**1184**
MONTENEGRO	**SERBIA**	**750**	**1797**
SERBIA	**BOSNIA_HERZEGOVINA**	**600**	**1418**
SERBIA	**BULGARIA**	**250**	**1500**
SERBIA	**KOSOVO**	**450**	**1438**
SERBIA	**NORTH_MACEDONIA**	**550**	**1300**
SERBIA	**MONTENEGRO**	**600**	**1797**
SERBIA	**ROMANIA**	**800**	**2539**
GREECE	**ALBANIA**	**250**	**1278**
GREECE	**BULGARIA**	**400**	**1170**
GREECE	**NORTH_MACEDONIA**	**300**	**2660**
ROMANIA	**BULGARIA**	**250**	**5313**
ROMANIA	**SERBIA**	**500**	**2539**
ITALY	**GREECE**	**500**	**500**
TURKEY	**GREECE**	**100**	**1317**

Planned and proposed interconnections and grid reinforcement in SE Europe: Besides the existing electricity interconnectors, several new lines are planned both between the EU member states (Greece, Italy, Bulgaria and Romania) and their Balkan neighbors as well as between the Balkan countries. Those include grid reinforcement projects that are expected to assist a viable cross border electricity trade. A number of regional concrete projects which are either ongoing or recently deployed are included in the latest ENTSO-E Ten Year Network Development Plan 2018. These most notably include:

- No 28/ Italy – Montenegro (in operation since November 2019)
- No 138/ Black Sea Corridor (Grid reinforcement project in Romania-Bulgaria)
- No 142/ CSE4 400kV line between Bulgaria and Greece (expected in 2023)
- No 144/ Mid Continental East corridor – Double circuit 400 kV power line between Serbia and Romania
- No 227/ Trans Balkan Corridor (Grid reinforcement project across Serbia and Montenegro)
- No 241/ Upgrading of existing 200kV lines between Croatia and Bosnia and Herzegovina
- No 243/ New interconnection line between Serbia and Croatia
- No 341/ North CSE Corridor (Grid enhancement in Serbia)
- No 342/ Central Balkan Corridor (East to West cross regional grid enhancement Bulgaria-Serbia-BiH)
- No 343/ CSE1 New (Grid enhancement project in Croatia-BiH)
- No 350/ South Balkan Corridor (includes an 400kV OHL between Albania-North Macedonia and two grid enhancement projects in North Macedonia.)
- No 376/ Refurbishment of the 400kV Meliti(GR) - Bitola(MK) interconnector

Rules for cross-border transmission capacity allocation: Even though interconnectivity has been increasing in a fast pace in the SEE region, with total interconnection capacity expected to rise by 50% until 2025, only a small fraction of the interconnection capacity is currently available to traders. The NTC values are currently small in all countries. Therefore, below 30% of interconnection capacities are on average available for commercial operations. In Greece, the NTC values range from 11% to 34% of the thermal capacity of interconnectors, while Large exporters, such as Bosnia-Herzegovina and Bulgaria, as well as smaller exporters such as Romania and Serbia, also use restrictive NTC values, which represent a range between 19% to 43% of interconnection capacities in these countries.

Currently the rules for allocation of available cross-border transmission capacities between regional bidding-zones include various schemes, such as: (a) Bidding over last accepted Marginal price, extensively used in DAM framework and (b) First-come first served scheme, used extensively in explicit auctions for capacity allocation in IDM framework (i.e. Serbia-Albania, Serbia-Montenegro etc.). Currently, the capacity allocation auctioning in SEE region is performed either via explicit auctions, auctions through Joint allocation Office (JAO), join auctions or split 50%/50% auctions.

The Integration of Electricity markets via the Target model market initiative is an ongoing process, so with regard to interconnection projects and bilateral market coupling initiatives, these are just blocks towards the building of an integrated multilateral regional market. ACER is in charge for the monitoring and surveillance of energy markets towards this direction, and its involvement is meant to enhance further electricity market development and ensure its smooth operation.

The SE European Electricity Markets

Electricity Market Liberalization: Legislation either pending or not enforced affects the establishment and development of organized day ahead electricity markets and/or the deregulation of retail electricity prices in Albania, Bosnia and Herzegovina (BiH), Kosovo and North Macedonia. More specifically:

- **Albania**: Wholesale electricity prices are regulated through an excessive public service obligation. Retail market is still highly regulated, while vertical integration of retail sales in the free market remain low, reaching only 11.19% in 2018.
- **Bulgaria**: Integral electricity market is not fully liberalized. There is low competition in domestic wholesale market as dominant producers dictate the market price in distinct time periods. Retail market is fully liberalized but offers low competition due to low prices in the regulated market. Recent legislative moves include the abolishment of the electricity export tariff, and vesting authority to the regulator (EWRC) to regulate the electricity volumes provided in regulated market on a monthly basis.
- **Romania:** Since December 2018 both retail electricity market for industrial and household consumers are liberalized with a transition period (till 1/3/2022), when the electricity price for household consumers will be capped.
- **Bosnia and Herzegovina:** Establishment of a day-ahead market has been delayed and therefore all non-regulated electricity provisional tariffs are product of bilateral agreements. Despite deregulated electricity prices retail markets are majorly dominated by respective incumbent utilities.
- **Montenegro:** Wholesale electricity prices are fully de regulated in Montenegro while the establishment of organized DAM is pending. Retail electricity prices are deregulated but the market offers low competition as industrial consumption is

low and household and small consumers are supplied by the dominant supplier EPCG.

- **Kosovo:** Kosovo has opted for its day-ahead and intraday market to be serviced by the Albanian power exchange upon its establishment. The liberalization of retail electricity market is postponed.
- **North Macedonia:** Legal framework for the establishment of DAM is in force since May 2018, while all retail prices for all electricity supply are deregulated since 1 July 2019.
- **Serbia:** SEEPEX operates since 2016, but its liquidity is limited due to the EPS monopoly and the lack independent producers. Retail electricity market is highly regulated as eligible consumers are a significant portion of the demand. Electricity prices are deregulated for MV and HV consumers since 2014 but there is low competition as EPS supplies the majority of the demand in the free market (98.3% in 2018)

Electricity Market Distortions: There are a number of integral electricity market distortions in SE European electricity markets which include: (a) inelastic electricity supply as a result of limited flexible generation amidst seasonal adequacy concerns (hydrological conditions), observed in Albania, (b) Restricted electricity volumes through DAM as a result to large size of regulated and bilateral market (i.e. Bulgaria), (c) Indirect subsidies to low utilization, carbon intensive and non-competitive units for cold reserve (i.e. Serbia, Bosnia and Herzegovina, Bulgaria, Romania), which was observed despite derogation of ETS until the end of 2019 in Romania and Bulgaria, (d) public loans for bail-out of State-owned electricity and heat producer (i.e. Romania), (e) Internal differentiation of rules of domestic wholesale electricity market between incumbents, which was observed in Bosnia and Herzegovina, (f) dominant producers' monopoly as a result of aggressive pricing approach deriving from its public service role (i.e. Serbia). On the other hand, the most significant regional electricity market distortion is the cross-border electricity market tightening due to non-utilized reserved cross-border transmission capacity.

Moreover, technical forecasting limitations lead to cross-border transmission capacity estimation inaccuracies. More specifically, discrepancies in data feed from Balance Responsible Parties (BRPs) and the overestimation of Transmission Reliability Margin (TRM), reserved for response to frequency deviations, emergency exchanges and other uncertainties, has led frequently to lower accuracy in estimating available NTC values for cross border trade. In addition, in SEE region, the inability of TSOs to estimate and assess transmission constraints, in a number of cases, has limited imposed NTC values. Moreover, NTC values, according to ECRB, has been affected by inaccuracies in power generation or demand forecast through the network model.

Integrated European electricity market and anticipated developments: The SEE region is in the process of promoting the EU goal for integration of electricity markets on the frameworks of DAM and IDM establishing a pan-European Single Day Ahead Market (SDAC) and Single Intraday Market (SIDC) respectively. A numerous number of market coupling projects are planned in the region, most of which are in the DAM framework. Most of the projects involving the Western Balkan countries have not progressed beyond primary status as certain preconditions and concrete maps of implementations are lacking. More specifically, such projects include the coupling of Albania – Kosovo, which can only implemented under the precondition of the establishment of Albanian Power Exchange (APEX), the Serbia-Montenegro-Albania market coupling and the AIMS project of DAM coupling between Albania – Italy – Montenegro – Serbia, which present no concrete roadmap for implementation. The sooner expected coupling project in the region is Greece – Italy Coupling of DAM, which is anticipated during 2020[1], while Greece's coupling with Bulgaria in the DAM framework is expected in 2021. One of the most important coupling projects in the region underway, is the coupling of the 4MMC markets with Germany-Austria-Poland, which is considered the first stage of integration of 4MMC with the MRC. In addition, on the Intraday level the XBID project aiming for implementing SIDC is expected to add the markets of Romania and Bulgaria along with Hungary and Croatia by 2019.

Outlook for Generation Investment and Business Development in SE Europe

The region of SEE has slowly entered a decarbonization trajectory, with most intensive efforts in the EU member states, namely Greece and Romania. RES investments have been progressing reluctantly in WB6 countries contrary to the recent past. More specifically:

Coal/Lignite Baseload Generation: Despite New Coal/Lignite investment in the region include Tuzla 7 TPP (450 MW) in Bosnia and Herzegovina, Ptolemaida V (615 MW) in Greece, Kostolac B3 TPP (320 MW) in Serbia, which are expected to come on stream in 2021, 2022 and 2024 respectively.

[1] There are some external risk factors regarding the completion of market coupling projects in 2020, again related to the Coronavirus outbreak, but nonetheless significant steps have been taken in this regard and discussions with the counterparties are intense.

Most ambitious lignite phasing out program is being promoted by Greece, aiming at decommissioning 3.8 GW, the entirety of Greece's lignite-fired power plant fleet, by 2023, with the newly deployed Ptolemaida V being operational on lignite until 2028 and switching to an alternative fuel onwards. Romania is in the process of adjusting to more ambitious goals as it recently drafted its updated NECP (31/01/2020), which anticipates the decommissioning of 1.26 GW of coal-fired baseload by the end of 2025. Bulgaria has a more modest decarbonization plan phasing out 665MW of hard coal capacity by 2023 and 738 MW of lignite-fired generation by 2030. Moreover, Serbia has chosen prioritization of refurbishment and revitalization of its lignite power plant fleet. The rest of the WB6 countries, namely North Macedonia, BiH, Kosovo and Montenegro do not have a concrete plan for phasing out their operational coal/lignite-fired power plants.

Nuclear Power Generation: The only Nuclear project in the region scheduled before 2030 is the much-anticipated Unit 3 at NPP Cernavodă (720 MWe) in Romania, expected to be commissioned in 2029.

Gas Projects: Greece is the only country in the region that has consciously chosen natural gas as a transition fuel, with two gas projects on the pipeline, one by Mytilineos S.A. (826 MW) already under construction and one by Elpedison (828 MW) under licensing procedure, expected to be connected to the grid in 2022 and 2023 respectively. Newly built gas power generating units in SEE region include Panchevo CCGT (200 MW) in Serbia and TEC Vlora CCGT (98 MW) in Albania, expected online as early as 2020 and 2024 respectively

Hydropower investments: Most of anticipated regional investments in hydropower plants are expected in Romania, Bosnia and Herzegovina and Albania, with projections of the added capacity based on the local authorities to exceed 1,250 MW, 480 MW and 370 MW respectively by 2030.

Table 2: RES Support Scheme and Current (2018) and Projected (2030) Installed Capacity of Variable RES in SEE

Country	RES support Scheme	Installed Capacity of Variable RES (MW)	
		2018	2030 (Projected)
Albania	CFD	25.6	132
Bosnia and Herzegovina	FiT	265	541
Bulgaria	FiT/ Premium Tarrif	2,154	3,875
Greece	Sliding FiP/ FiT	5,422	15,522
North Macedonia	FiT/FiP	174	293
Kosovo	FiT	162	496
Montenegro	FiT	379	737
Romania	Quota System/ Subsidies	4,741	7,903
Total		13,322.6	28,687

Investments in variable RES: Currently, the biggest investor in variable RES units is Greece followed by Romania. All regional markets have some RES support scheme deployed in order to create incentives to accelerate investment. Based on national targets set by each country and documented estimations by local authorities the projected in installed capacity of variable RES in SEE is expected to double by 2030 exceeding 26 GW. Again, the main investor is projected to be Greece with total installed capacity exceeding 12.5 GW.

Quantitative Analysis of the Electricity Market Integration in SE Europe, the Target Model and Procurement Opportunities for Energy-intensive Industries

The analysis part of the study includes a whole Chapter with quantitative projections of the electricity generation system and the electricity market of the South-East European region (SEE) into the future. The projections correspond to scenarios, which reflect different assumptions regarding the degree of market integration, the restrictions in the use of electricity interconnections and the evolution of the structure of electricity-generating capacities in the SEE region. The projections cover the period 2020-2030 yearly.

The modelling approach: The projections of the electricity generation system and the electricity market of SEE use the **PRIMES-IEM model**, which simulates power generation, the wholesale markets and the power flows over interconnections simultaneously for all the SEE countries. PRIMES-IEM model is a deterministic model that solves a mathematical programming problem formulated as an integer optimization problem, under demand and system constraints, including the provision of ancillary services, interconnection possibilities and technical restrictions of the cyclical operation of the power plants. Furthermore, the model simulates in a single-shot, i.e. simultaneously, the sequence of wholesale markets, i.e. day-ahead, intra-day and balancing, including the transactions performed bilaterally, outside the organised markets. The results of the model show projection into the future of the generation mix, wholesale market prices and import-exports in hourly resolution per year.

After the simulation, a **Sub-model for retail price estimation** projects into the future the electricity prices in the retail markets, by sector of consumption and country. The pricing model uses the result of the unit-commitment PRIMES-IEM model to determine the marginal costs of the horizontal slices of a load duration curve that correspond to the customers' profiles. The algorithm considers as horizontal slices the operation of the power plants and matches them with the respective customer class based on its demand profile. The model also includes a price mark-up for each customer that should be inverse to the price elasticity of demand for this customer. The level of mark-ups is varied until matching the required amount in order to recover the missing fixed costs from the price mark-up, according to Ramsey pricing principle.

Main Assumptions: The common assumptions under all scenarios are: (a) Electricity demand by country, (b) Demand for ancillary services by country, (c) Fuel prices by country, (d) Cost of power generation technologies, (e) Carbon price (ETS), (f) Capacity factors of RES technologies, (g) Technical parameters regarding the operation of the power plants, (h) Capacity and technical parameters of storage facilities, (i) Electrical capacity of interconnections.

Scenarios: The selected scenarios for the analysis include a **Business as Usual scenario (BAU)** and 4 alternative scenarios incorporating different assumptions for (a) extent of market coupling, (b) degree of use availability of interconnections to the markets, (c) development of RES in the WB6 countries, (d) decommissioning and investment for solids-firing and gas-firing plants in the various countries and (e) Implementation of the EU policy in the WB6 countries.

EU alone: Includes carbon pricing only for EU MS. In addition, only EU MS apply target Model, with gradually improving coupling between them (2023-2025), while full coupling is achieved by 2030. WB6 countries operate segmented electricity markets with restrictive NTCs as today.

WB trade: Includes carbon pricing only for EU MS. WB6 do not follow the rest of EU energy and climate policies, therefore solid-fired generation persists, while they develop RES well below potential. NTC values increase for all interconnections (EU MS and WB6)

WB gas: Includes carbon pricing only for EU MS. WB6 slowly replace solids-fired plants with new gas firing plants to maintain capacity adequacy, increase trade and reduce carbon emissions. Moreover, WB6 develop renewables, above BAU but modestly compared to potential NTC values increase for all interconnections (EU MS and WB6)

Full EU: Includes carbon pricing for both EU MS and WB6. All countries apply EU policy on RES, market coupling, emissions. Full market coupling and increased NTCs apply. Solid-fired plants in WB6 are decommissioned fast. Gas units develop in WB6, though not as much as in the WB gas case, due to significant RES development. Balancing requirements increase in the whole region.

Table 3: Definition of Scenarios

Scenario name	RES growth	Balancing of RES and Trade	Solids-firing plants in WB6	Market Coupling	Interconnections and NTC	Carbon emission pricing
BAU	Low	Conventional	Maintained	No	Restricted by NTC	Yes, for EU MS, No for WB6
EU alone	Low	Conventional	Maintained	Only EU	Increased only among EU MS	Yes, for EU MS, No for WB6
WB trade	Low	Trade	Maintained	Partial with zone splits	Increased	Yes, for EU MS, No for WB6
WB gas	Medium	Gas	Slow phase-out	Partial with zone splits	Increased	Yes, for EU MS, No for WB6
Full EU	High	Trade	Fast phase-out	Full	Maximum	Yes, for EU MS and WB6

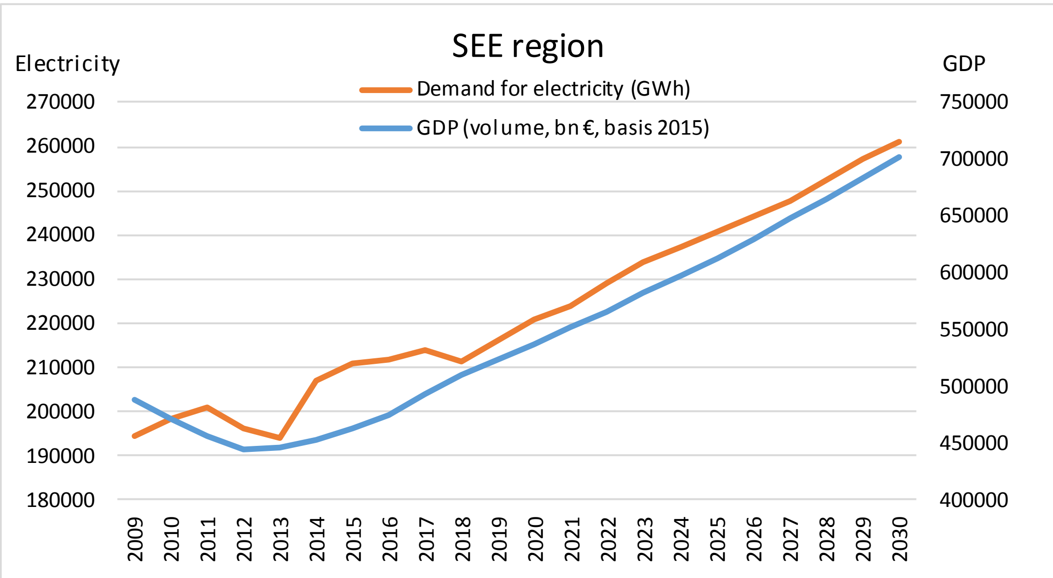
Assumptions about the infrastructure and power plant fleet: The assumptions about the interconnection investment in the SEE region in the period until 2030 draw on the Entso-e's TYNDP 2018. While the assumptions on the power plant investment were made for each country based on TYNDPs of regional TSOs and national energy and climate plans for EU member states.

Table 4: Interconnections Under Construction in the SEE Region

Country 1	Country 2	Commissioning year	Thermal Capacity of the new interconnector (MW)
ALBANIA	**NORTH_MACEDONIA**	2020	1330
BOSNIA_HERZEGOVINA	**SERBIA**	2025	1300
BOSNIA_HERZEGOVINA	**MONTENEGRO**	2020	1300
BOSNIA_HERZEGOVINA	**CROATIA**	2025	1300
BULGARIA	**ROMANIA**	2020	1300
BULGARIA	**GREECE**	2023	1500
KOSOVO	**NORTH_MACEDONIA**	2025	1300
MONTENEGRO	**ITALY**	2020	600
SERBIA	**ROMANIA**	2025	2*1300
SERBIA	**MONTENEGRO**	2030	1300
ROMANIA	**UKRAINE**	2025	1300

Assumptions on electricity demand: All scenarios share the same projections of economic activity, demographics and demand for electricity. The projections assume steady economic growth over the entire projection period.

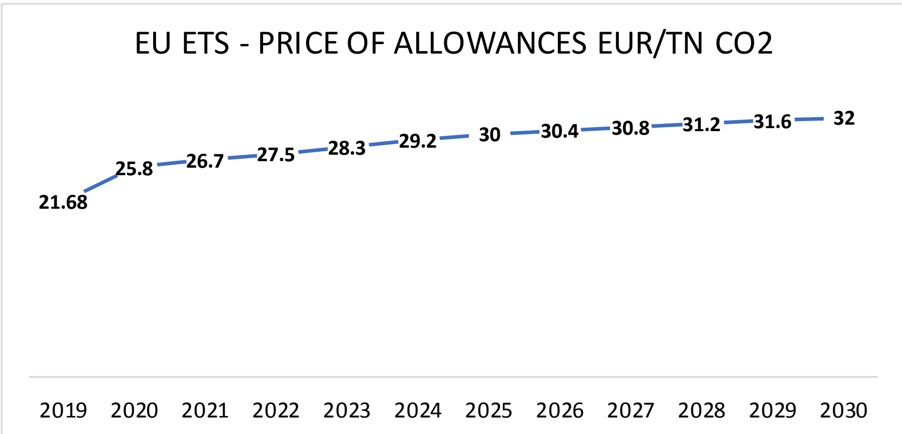
Figure 2: GDP and Demand for Electricity in the SEE Region



The average annual rate of growth of GDP in volume over the decade 2020-2030 is projected to range between 1.5% up to 3.5%, on average in the region. Improved living standards and industrialization drive the increased demand for electricity. The three EU MS produce 83% of regional GDP and consume 67% of total electricity. BiH and Serbia represent more than 2/3 of WB6 system.

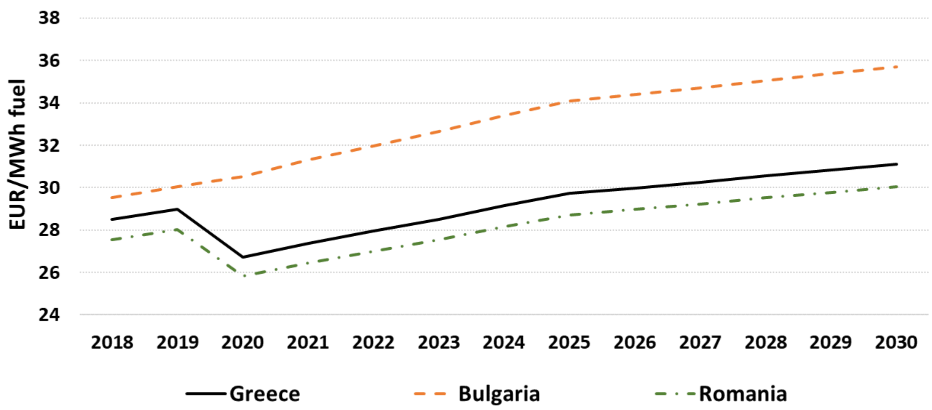
Outlook of fuel and generating costs: In the SEE region, the relative costs of thermal power generation depend mainly on lignite costs and natural gas prices. Historically cheap lignite allowed for affordable and stable electricity prices in SEE region. However, it is highly uncertain whether direct or indirect subsidies to lignite mining can survive in the future, to prevent lignite costs from rising in all countries of SEE except Greece, where lignite mining subsides have already been abolished. Therefore, the projections draw the high end of estimated lignite costs for each country driven by diseconomies of scale and stricter environmental legislation coupled with low investment in refurbishment. Lignite costs currently are ranging from 4.8 €/MWh-fuel (low end price) in Bulgaria to 13.6 €/MWh-fuel (high end price) in Greece.

Figure 3: Assumption of EU ETS Carbon Prices



In addition, EU ETS prices reduce lignite competitiveness and potentially modify the merit order. However, it is uncertain when and to which extend carbon pricing will apply in the non-EU countries of the SEE. The incremental trend of projected EU ETS prices is driven by the application of the Market Stability Reserve (MSR), as reformed in 2018. And even though the granting of free allowances in Bulgaria and Romania has preserved lignite rank in the merit-order until today, the expected application of the auctioning of allowance post-2020 also in these two countries will certainly further trouble power generation using solid fuels. The EU ETS projection relies on recent scenarios quantified for the European Commission using the PRIMES model. The projections assume an effective implementation of the NECPs of the EU MS, which plan for a significant increase in vRES and include ambitious coal phase-out plans in all countries.

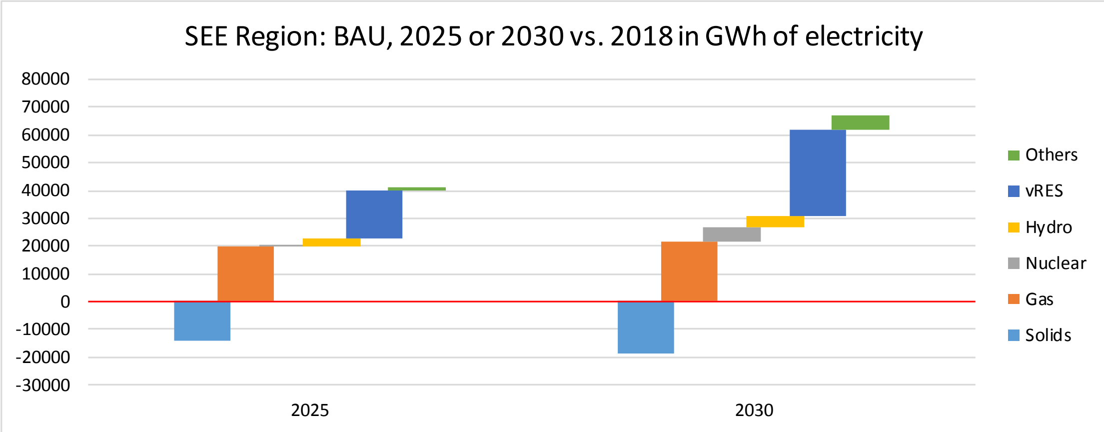
Figure 4: Projected Gas Price in Power Generation (Incl. Transport and Balancing Costs)



The present Working Paper assumes for all scenarios that the average natural gas prices in imports increase only slightly during the next decade reflecting broader gas market conditions. Rising LNG supplies originating from US shale gas compete strongly with – until now dominant – pipeline gas. This happens mainly in the South of the region, but also in various other places in Europe. Moreover, Gas supply is not uniform in the SEE and does not provide gas-to-gas competition to allow stable gas prices. Specifically, the lack of gas interconnections and diverse entry points in WB6 countries and to a lesser extent in Bulgaria contribute further to gas pricing and supply uncertainty. Thus, only Greece, and Romania, are likely to experience gas supply expansion.

Outlook of power capacities and generation: The analysis of the onward performance of power system of SEE region reveals that EU MS' electricity system represents roughly two-thirds of the system of the entire SEE region. The assumption that in all scenarios the EU MS countries apply fully the EU legislation, as reflected in their NECPs, implies that already in the **BaU** scenario the entire region sees a substantial reduction of solids-based generation in favour mainly of gas and vRES. Driven by targets becoming imperative in the EU MS, the vRES increase considerably and in particular towards the end of the decade they outweigh growth of gas-based generation. For the remaining one third of system of the region, i.e. the WB6 countries, the restructuring of the generation mix is highly uncertain due to absence of new investment prospects.

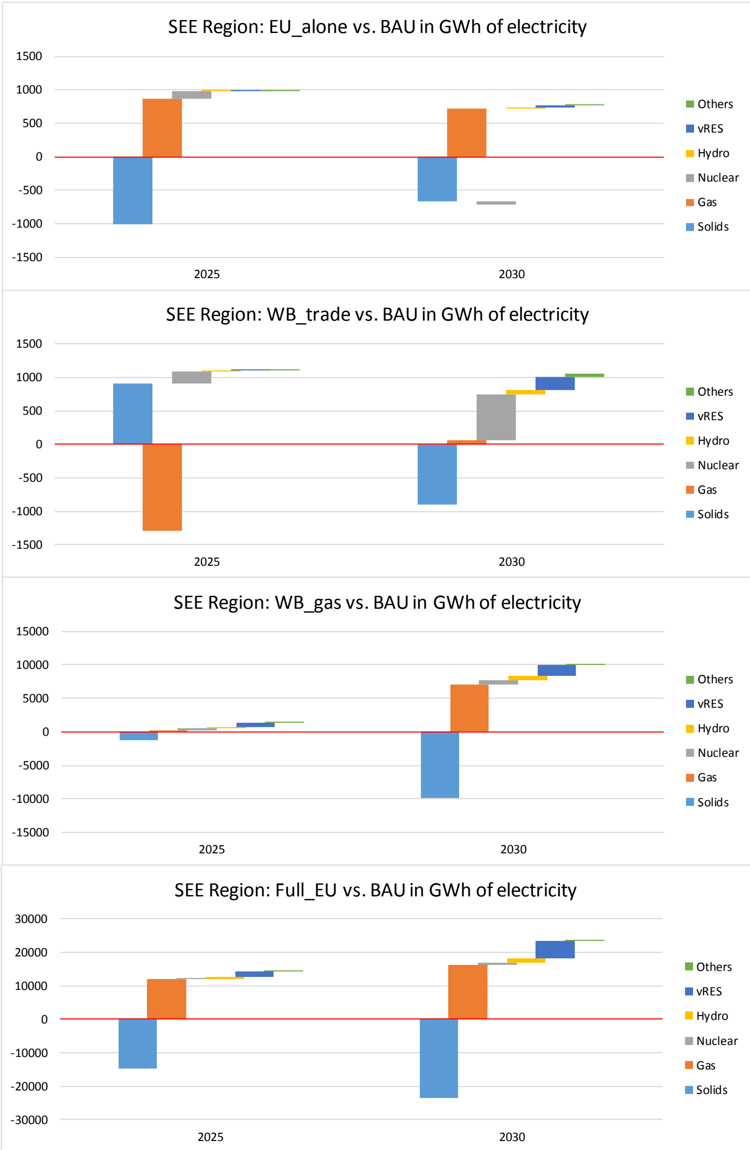
Figure 5: Overview of Power Generation Mix in the SEE Region (BAU Scenario)



WB trade scenario: The opening of cross-border trade in the WB trade scenario, assumed to take place without applying carbon pricing and vRES policies in the WB6 countries, implies, in the medium term, a substitution of gas by solids-based generation in the region as a whole, albeit at a small magnitude. Total generation from solids increases only by 1.5% compared to the BAU projection. In the longer-term, the expansion of nuclear capacity in Romania benefits from trade opening, cancels gas substitution by solids and pushes solids-based generation further downwards than in the BAU (-1.5% in 2030).

WB gas scenario**:** The opening of cross-border trade, accompanied by gasification of the WB6 system, as under the WB gas scenario assumptions, drives a certain substitution of solids by gas in power generation in the entire region, both in the medium and longer-term compared to the BaU. The increase in total gas-based generation is small in 2025, less than 0.5% compared to the BAU, but it is significant by 2030: 17% up from gas-based generation in the BAU projection. By assumption, the vRES get a push in this scenario compared to the BaU, albeit small and below potentials. The changes in the power generation mix imply a reduction of solids-based power generation, which decreases by 1.7% in 2025 and 14% in 2030.

Figure 6: Overview of Power Generation Mix in the SEE Region (Comparison of All Alt. Scenarios to BAU)



Full EU scenario: The combination of trade opening with carbon pricing and the implementation of RES policies in the entire region, as assumed in the Full EU scenario, implies a substantial substitution of solids by gas and vRES, compared to the BaU, both in the medium and longer-term. The reduction of solids-based generation is close to 20% in 2025 and to 32% in 2030 compared to the BAU; the detrimental effects on solids are much higher than in WB-gas scenario, compared to the BaU. The vRES increase substantially in the longer-term and contribute as much as gas to the replacement of solids in power generation. The carbon pricing in the WB6 is of crucial importance for enabling the implementation of the full-EU policies and targets in the entire region.

Trends in electricity trade: Historically, Bulgaria, Romania and Bosnia Herzegovina stand out as traditional net exporters of electricity. Serbia has often been an exporter but to a lesser extent compared to the other three but has also been a net importer over several years. The remaining countries are systematically net importers of electricity. Greece is the largest net importer in the region, followed by North Macedonia and Albania. The latter seldom becomes a net exporter when hydro resources are high. Montenegro and Kosovo have rather balanced electricity exchanges. Taken as a whole the SEE region is a net exporter of electricity, but the overall net balance strongly fluctuates over time due to dependence on the availability of hydro resources, which follow a cyclical variation.

Figure 7: Net Imports of Electricity by Country in GWh Yearly

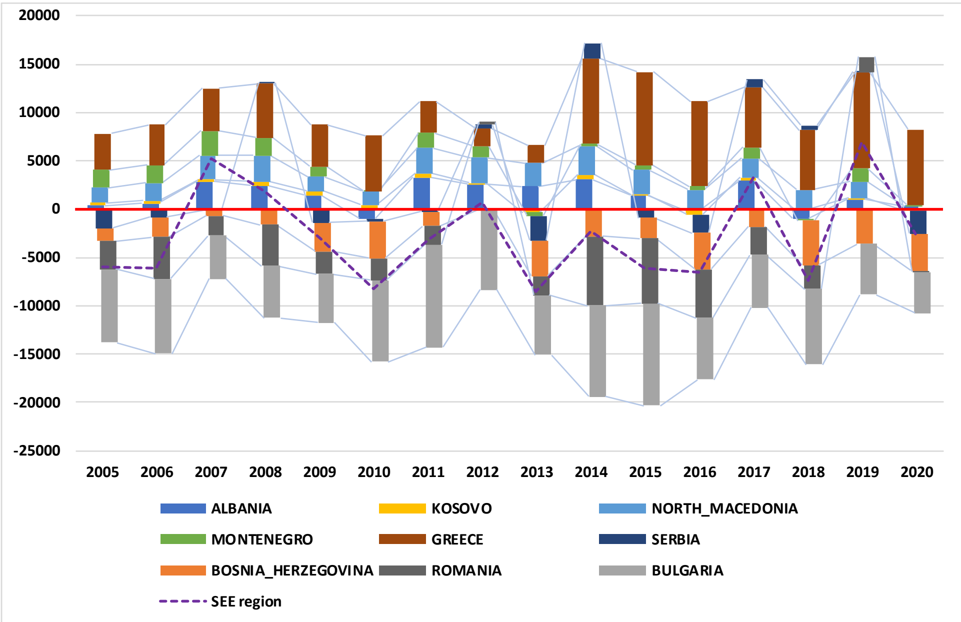
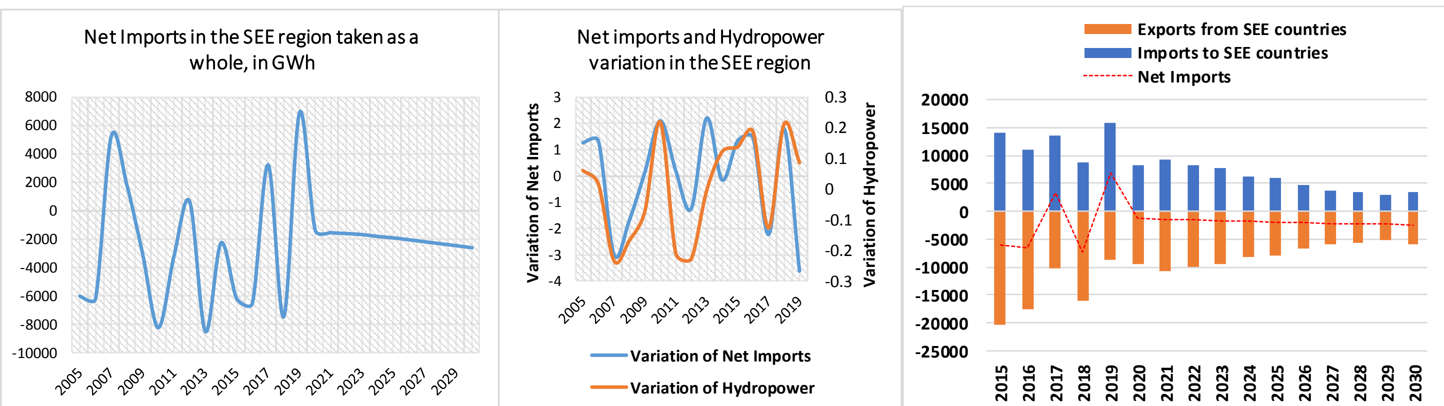
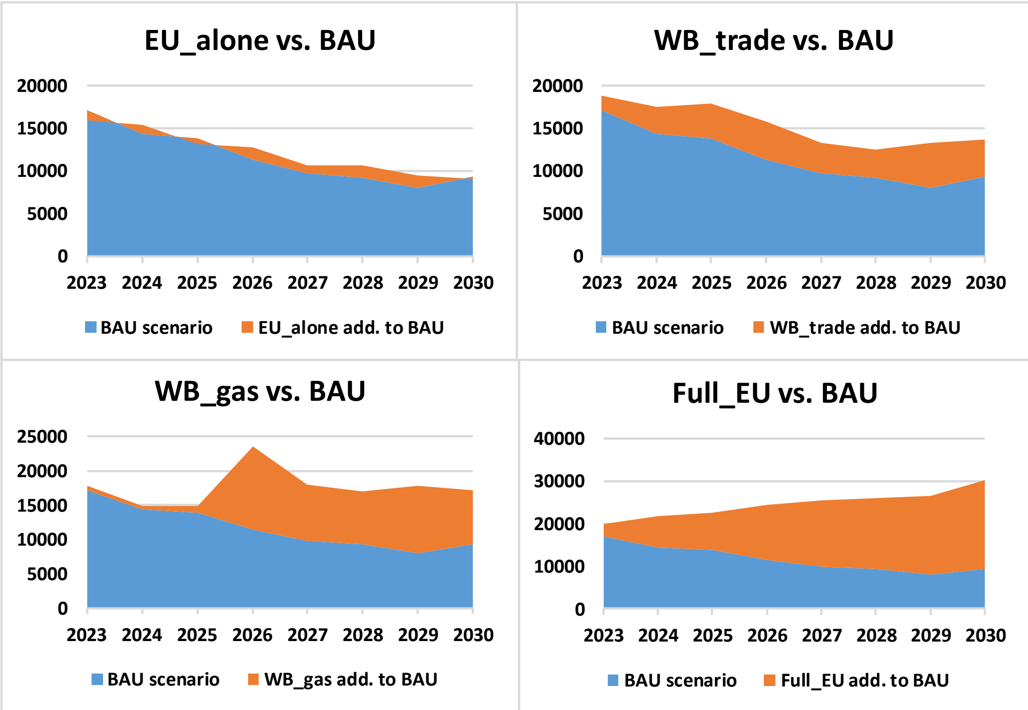


Figure 8: Historical Net Imports in Correlation with Hydropower Resource Availability and Projected Electricity Exchanges (BAU Scenario) for the SEE Region, Taken As A Whole



The projections for the **BAU scenario** show that the decrease in exporting capabilities leads to a significant decline in the total volume of electricity exchanges in the SEE region. The reduction is already visible in the recent years. Moreover, under conditions including relative stabilization of gas prices in the South and excess thermal electricity during sunny days, a new form of electricity trade can emerge based on exports originating from CCGT units in the South, mostly in Greece.

Figure 9: Total Volume of Trade, GWh



Increasing the NTC values and performing market coupling only among the three member-states of the EU (**EU alone scenario**) is found to have the lowest impacts on total volume of electricity exchanges, among all the scenarios examined. The carbon pricing and the development of renewables (**Full EU scenario**) induce profound changes in the merit order of power plants and the balancing requirements, rendering gas-based generation more valuable for energy and services compared to traditional sources of the region, such as lignite. The traditional exporting capabilities decline in this context and gas-based electricity flows from the South to the North emerge. The total volume of electricity exchanges increases up to 200% in the long-term compared to the BAU projection

In **WB trade scenario** conditions total volume of electricity exchanges in the region increases by 35% - 47% compared to the BAU as a result of increased lignite-based exports from the Western Balkans. In **WB gas scenario** total volume of electricity exchanges also increases by roughly 100% especially on the latter half of the decade as a result of gas supply and gas-based generation facilities in the Western Balkans

Net Imports in various scenario projections: With regard to net electricity imports, Greece is projected to see a decrease of its import dependence and even becomes net exporter in the full EU scenario. Romania is projected to see relatively small inflation of net electricity imports over the decade. Moreover, Bulgaria is projected to see its net exporting capability continuously decrease along with its lignite-fired overcapacity. Furthermore, the market coupling of only EU MS in EU Alone scenario has little effects on trade in SEE region, just because it does not include the WB6.

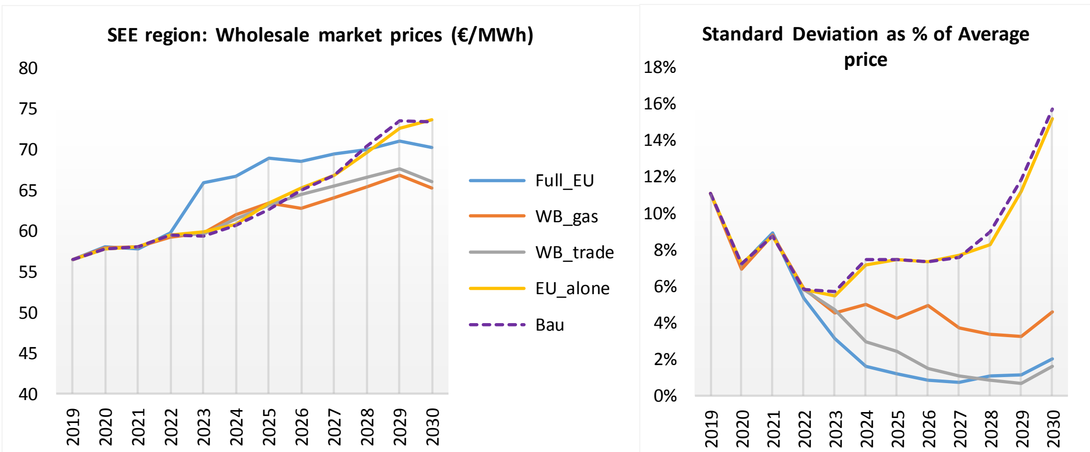
The exporting capability of BiH is maintained except if pricing carbon emissions applies, while introduction of domestic gas infrastructure, under WB gas scenario increases exports in the long term. Serbia's net electricity exports show a continuous decline under all scenarios except Full EU scenario, where the application of carbon pricing turns Serbia into a significant net exporter early in the decade. Montenegro show high and growing import dependence under all assumptions. Albania remains a net importer in the long term under all scenarios. Moreover, North Macedonia also in all scenarios, with net imports projected to increase significantly in the Full EU scenario due to RES balancing and uneconomic lignite-based generation. Kosovo may become adversely dependent on imports both when pricing carbon emissions and if gas-based trade develops in WB6.

Projections of wholesale market prices: The projections show that the wholesale market prices are likely to increase in the future as a weighted average over the entire SEE region. The main reason is the discontinuity of having a non-expensive and abundant generation of electricity from solid fuels, as respective units become obsolete and further inefficient over time. The rise of lignite costs, due to the increase in mining costs (dis-economies of scale) and the carbon emission pricing, render expensive generation from solid fuels even if new efficient units were built. New efficient CCGT units fail to develop, except in Greece, and thus the market prices cannot benefit from the stability of gas prices as much as possible. The development of variable RES, even if at a modest pace in some of the countries, implies an increase in reserve requirements, while load increases and over-capacity erode as new investments are insufficient. The increasing scarcity of balancing resources combines with the poor investment in new hydropower units and the lack of efficient gas plants and drives system costs upwards, hence overall marginal system prices tend to increase.

The opening of electricity trade possibilities in the WB-trade and WB-gas scenarios, where carbon pricing does not apply to the WB6 countries, significantly mitigates the trend of rising wholesale market prices. The development of new gas plants in the WB-gas scenario further reduces market prices compared to the BAU projection, rendering WB-gas the scenario with the lowest market prices among all projections. On the other hand, the opening of electricity trade between the three EU MS (Greece, Romania, Bulgaria) is not enough to drive a reduction of average wholesale market prices, which remain hardly below the BAU projection.

Furthermore, the application of carbon pricing in the whole region results in a significant increase in market prices, compared to the BAU projection, with prices increase relative to 2019 by 6% in 2022, 17% in 2023 and around 20% continuously after 2024. However, the in the increase in prices in the Full-EU scenario is lower in the long-term (2030) compared to the increase in prices under the assumptions of the BAU and the EU-alone scenarios. Most notably price convergence is below 5% of average regional prices continuously after 2023 only in the Full EU, WB gas and WB trade scenarios, in which increased interconnection capacities in the entire region are available.

Figure 10: Average Wholesale Market Prices in the SEE Region



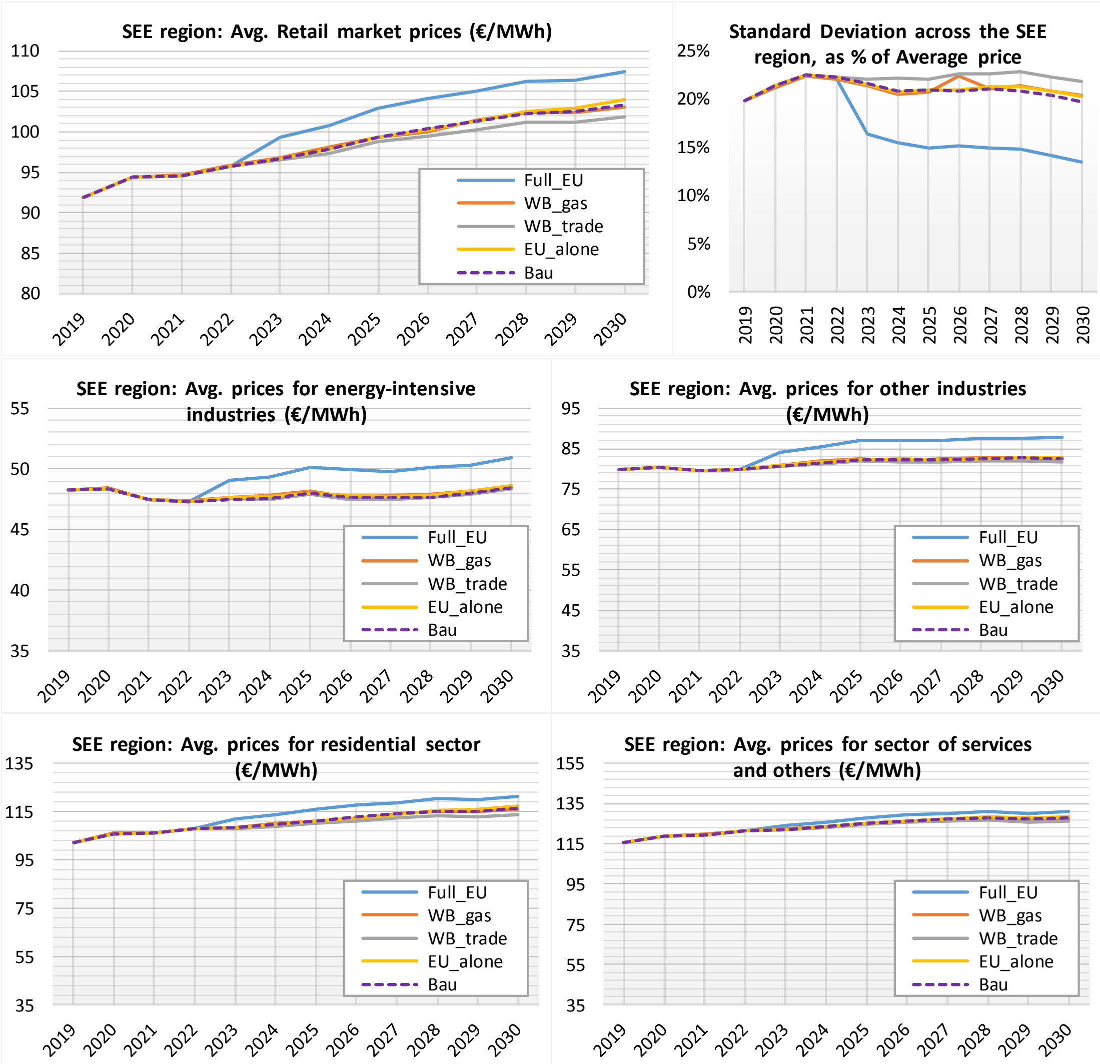
In Greece, wholesale electricity prices are expected to increase after 2023 following the regional trend but decrease relatively to the average prices in the SEE region. Moreover, abolishment of NTC restrictions is projected beneficial for wholesale prices in Greece. In Bulgaria, trade opening mitigates overall upwards pressure to wholesale electricity prices. Full EU scenario increases prices in Bulgaria post 2023, but on the long run leads to lower prices than the ones projected under the impact of NTC restrictions, i.e. BAU and EU alone scenarios. In Romania overall wholesale prices increase due to carbon pricing and balancing cost of vRES, while the increase is mitigated by the opening of trade in the region. Moreover, wholesale prices fall below regional average significantly in BAU and EU alone scenarios, and less in in the scenarios with full opening of trade possibilities. In Bosnia and Herzegovina, restrictive NTCs and domestic resources preserve low market prices before 2023, while from 2023 onwards trade opening brings prices up to the SEE average.

Wholesale electricity prices in Serbia and North Macedonia, are projected to increase significantly in BAU and EU alone scenarios driven by the increasing lignite costs, obsolete power plant fleet and the reluctance to develop modern and efficient gas-based generation. Moreover, carbon pricing and increase in balance requirements due to the development of vRES add to the increase of prices in both countries. In Kosovo NTC restrictions keep prices low, while the main conditions driving electricity price to increase are carbon pricing and opening of cross border trade based on gas. In Albania prices are projected to remain below regional average only when restrictive NTCs apply. Overall prices in Albania increase due to scarce domestic balancing resources (hydro) and trade opening, which rises prices above the regional average in respective scenarios, (i.e. WB trade, WB gas). For Montenegro there are rather stable prices projected when restrictive NTCs are present, while both carbon pricing and opening of trade drives prices up.

Projection of retail electricity market prices

The projection of retail market prices of electricity assumes that the sellers of electricity have concluded adequate contracts for economic differences with power generation units and are able to set the price levels so as to recover total costs of the portfolio of power generation assigned to each customer type.

Figure 11: Retail Market Prices Averaged in the Entire SEE Region



Overall retail electricity prices are projected to record a steady increase in all scenarios and sectors, with Greece being the only exception. A factor that can mitigate this increasing trend is the development of variable renewables, which have low and further decreasing capital costs. The levelized unit cost of vRES is lower than the average cost of power generation in the future. Of course, variable renewables need balancing resources, the cost of which is higher than the costs of renewables and is increasing in the future also due to scarcity of balancing resources as variable renewables increase in terms of their share in total power generation. The analysis estimates the balancing costs in detail, based on the simulations of the systems and the reserve markets, and adds them up to the total costs that revenues based on consumer prices will have to recoup. Nonetheless, the dropping capital costs of variable renewables is a factor that helps to mitigate the upward trend of electricity prices despite the increasing cost of balancing variable renewables. Nonetheless, few countries, Greece is mainly the case, develop variable renewable to the extent needed to see a decreasing trend of consumer prices. In most countries, barriers to investment of various kinds and insufficient support policies do not exploit the renewables as much as the potential economic benefits would suggest.

Greece is expected to see stable retail electricity prices over time, with prices for energy intensive industries decreasing slightly as a result to low cost PPAs provided by portfolios with vRES, gas and hydro. In addition, the Greek retail prices are projected not to be affected significantly by the trade opening, gasification or carbon pricing in the Western Balkans. Retail market electricity prices in Bulgaria and Romania tend to increase across all scenarios and sectors as a result of carbon pricing without free allowances, poor development of variable renewables and efficient gas units and increasing mining costs. In the case of Romania prices for energy intensive industries are shown to be relatively stable in the future, but to increase in the context of Full EU scenario.

In the case of Bosnia and Herzegovina, trade opening and increased exports pushes retail prices down. This occurs as a result of collection of revenues from markets where higher prices prevail and for less costly allocation of fixed costs. In addition, the EU Acquis implementation is detrimental for retail electricity prices in BiH driving them as much as 10% upwards in comparison to BAU scenario. Retail electricity prices in Serbia are highly vulnerable to carbo pricing, with lignite-based exports and possible deployment of efficient gas units helping keep prices low. In the cases of both Serbia and BiH retail prices remain below SEE average as a result of hidden subsidies and under-pricing, conditions that erode if regional market coupling applies, driving prices upwards.

In North Macedonia retail prices increase under BAU scenario, due to increased lignite costs and lack of more efficient gas development. Moreover, prices are projected to drop under full EU and WB gas scenarios, due to gas imports or development of domestic efficient gas units, with the effect of gas imports being visible only in the short term. Retail prices in Kosovo are projected to be much lower than the SEE average due to under-pricing lignite capital costs and mining costs, with prices however being pushed upwards by carbon pricing and regional gasification. Retail prices in Montenegro are low as BAU assumes also persistence of under-pricing and stable prices resulting from lignite providing balancing for vRES development. However, pricing of carbon emissions and full trade opening is projected to increase Montenegrin retail electricity prices. Prices in Albania are expected to follow the true costs, exhibiting stability across scenarios with the Albanian market benefiting by the opening of trade opening in the region.

Key Challenges and Opportunities for the Greek Industry

As part of its terms of reference, the present Working Paper looks into the impact of European and regional developments on Greece's electricity market. In this context, it is important to note that the electricity mix in the SEE region is changing significantly, affecting Greece's electricity market. Lignite costs in WB6 are rising due to diseconomies of scale, while no investment for fleet modernisation is currently available. Regionally, the traditional power fleet becomes obsolete and uneconomic, while new resources (vRES, gas) fail to develop adequately. The reduction of solid fuels, used for power generation, from the regional electricity mix and the reduction of overcapacity due to poor investment is expected to drive down the volume of electricity exchanges in the region, reducing the volume of cross-border electricity flows available for the Greek system. The exporting role of lignite-fired powered systems, namely Serbia and Bosnia and Herzegovina, will be relevant only for a short while and only if carbon emission pricing is not applied and new interconnections can facilitate the exporting capacities. But eventually due to deterioration of lignite-fired infrastructure and increased demand, WB6 countries may become net electricity importers. Gasification is not a likely development in the WB6 countries, and if it develops that will be in the extent to balance their systems rather than to support exports. The full EU-Acquis communautaire implementation constitutes a game changer in the SEE region. In this regard, full market coupling leads to exploitation of complementarities of Greek power system with regional one. That occurs on a daily basis, as the fleet of efficient gas units of Greece has large opportunities to export electricity at times when generation from RES is abundant and also when the gas fleet provides fast ramping services. On the other hand, during sunset and early in the morning it is mutually economic beneficial for Greece and the region to see electricity flowing towards Greece. However, high complexity of the routes of electricity flows require the entire region to have developed interconnection capacities fully available to the market, including the grid interconnections with WB6, which are projected to be more often in congestion than the connections with the EU MS.

Greece is projected to develop regional electricity interconnectivity of 14-24% and 17-25% by 2025 and 2030 (BAU low – Full EU high). Still the Greek system faces obstructions due to congestion from 2023 onwards. The new interconnection line between Greece and Bulgaria in 2023 is anticipated to allow an increase in direct energy exchanges between Greece and Bulgaria and limit transit flows through North Macedonia. Potential decoupling of electricity demand from GDP due to improvement of energy efficiency in all electrical equipment and appliances, including lighting implies a downward trend in demand that the new uses, such as heat pumps and transport hardly offset. Therefore, stable or slightly increasing demand for electricity may discourage investment, which raises concern for security of supply. At the same time new investment may see decreasing rates of use while providing services to a system with highly increasing variable RES. Moreover, the evolution of regional gas prices will affect the trajectory of the regional electricity mix.

Conclusions and Recommendations

a. The target Model is expected to increase market transparency, providing market participants with relatively good knowledge of market performance and ultimately simulating a perfect competition. However, a level-playing field is not given and is at stake as long as carbon pricing does not apply uniformly in the region.

b. Average increases in retail electricity prices in the SEE, except in Greece and few other countries developing RES, are expected in 2020-2030. Full EU policy implementation will increase retail prices in systems highly dependent on lignite (i.e. RS, BA, XK, ME). The Greek electricity market as a result may become regionally competitive early in the decade. In addition Greece, is projected to be the only country in SE Europe that will see stable or declining retail electricity prices in the latter part of the decade, with prices falling from +25% early in the decade to below +15% in 2030 and below +8% should Full EU policies apply across SEE.

c. Retail electricity prices are expected to drop significantly for electricity intensive industries in Greece until 2025, i.e. below 43 €/MWh and are expected to remain relatively stable throughout the rest of the decade and for all scenarios, except if Full EU policies apply across the region. The latter scenario foresees overall wholesale prices to increase due to higher balancing cost of variable renewables, pushing retail prices upwards to 45.5 €/MWh, while affecting the industrial electricity market of Greece.

d. Retail electricity prices for Greek industries, that do not depend on electricity costs for their competitiveness, are not expected to become regionally competitive during this decade, i.e. until 2030. Only in Romania retail prices converge with the Greek retail prices of the respective segment at 105.5 €/MWh in 2024.

e. The most competitive retail electricity market for other industries remain Bosnia and Herzegovina with prices spanning between 50.3 €/MWh and 58.6 €/MWh under all scenarios, followed by Kosovo and Serbia.

f. The future low-cost electricity supply is a composition of a large portion of variable renewables with efficient balancing resources based on efficient gas units, hydropower and imports at adequate times. Various systems in SEE will be more competitive than the Greek system in the shorter-/longer-term. Therefore, industrial consumers should either adjust their consumption profile to reduce electricity costs or seek electricity supply via PPAs at a lower cost from the neighboring markets.

g. As overcapacity erodes in SEE region, due to diseconomies of scale for the lignite-fired baseload generation, costs tend to rise. Moreover, the prospect of carbon emission pricing in the Western Balkans and the slow deployment of large-scale RES discourages modern investment in almost the entire region. As a consequence, costs and wholesale prices of electricity tend to increase in the entire region, except in Greece and Albania, while electricity exporting capacities decline.

h. The general conclusion is that cheap electricity in SEE from now on will become scarce. In this context, expanding cross-border interconnection capacity is of utmost importance for achieving price convergence in the region and allowing the Greek system to balance out increased input from variable renewables in a cost-effective manner.

There are significant concerns by Greek power-intensive Industrial consumers that the selection of the central dispatching option for Greece's implementation of the Target Model will lead effectively to a more cost intensive market pushing prices upwards in DAM. The concerns derive from the fact that Greece has already a long experience with central dispatching markets, i.e. mandatory pool, which led to a unit-based price formation in the internal electricity Market of Greece. Also, these concerns are consolidated due to the proposed[2] significant restriction of the volume of bilateral contracts with physical delivery per producer, as such practice is not applied in the mature European electricity markets. However, it remains to be seen if block biding of diversified portfolios, including RES, combined with a mature and less restricted bilateral market will increase competition and counteract those concerns in the midterm.

[2] Not yet defined by law