Energy Technology and Governance Program:

# SEE Electricity Market Perspectives until 2030

## Assessing the Impact of Regional Connections to Italy

***- Final Report –***

Southeast Europe Cooperation Initiative (SECI) Transmission System Planning Project
Cooperative Agreement AID-OAA-A-12-00036

January 18, 2017

This report made possible by the support of the American people through the United States Agency for International Development (USAID). The contents are the responsibility of the United States Energy Association and do not necessarily reflect the views of USAID or the United States Government.

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*Prepared for:*

**United States Agency for International Development**
*and*
**United States Energy Association**


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# Contents

# ABBREVIATIONS

| | | |
|---|---|---|
| SECI | – | Southeast Europe Cooperation Initiative |
| USEA | – | United States Energy Association |
| USAID | – | United States Agency for International Development |
| EKC | – | Electricity Coordinating Center |
| EIHP | – | Energy Institute Hrvoje Požar |
| TSO | – | Transmission System Operator |
| PEMMDB | – | Pan European Market Modelling Database |
| HVDC | – | High Voltage Direct Current |
| TPP | – | Thermal Power Plant |
| HPP | – | Hydro Power Plant |
| NPP | – | Nuclear Power Plant |
| PS | – | Pumped Storage |
| RES | – | Renewable Energy Sources |
| TYNDP | – | Ten Year Network Development Plan |
| RoR | – | Run of River |
| O&M | – | Operation and Maintenance |

**Countries / regions:**

| | | |
|---|---|---|
| SEE | – | South East Europe |
| AL | – | Albania |
| BA | – | Bosnia and Herzegovina |
| BG | – | Bulgaria |
| CE | – | Central Europe |
| GR | – | Greece |
| HR | – | Croatia |
| HU | – | Hungary |
| IT | – | Italy |
| KS | – | Kosovo*[1] |
| ME | – | Montenegro |
| MK | – | Macedonia |
| RO | – | Romania |
| RS | – | Serbia |
| SI | – | Slovenia |
| TR | – | Turkey |

[1] This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo Declaration of Independence.

# 1 EXECUTIVE SUMMARY

The ultimate goal in today's electricity business in Europe is market integration on pan-European level that will introduce transparency and competition between market players, incentives to clean energy development, as well as high quality of supply to the end-customers. In South-East Europe (SEE) there are uncertainties for the East-West and North-South transmission adequacy, linked with the possible new undersea HVDC connections between SEE and Italy, the connection of Ukraine to the rest of the Europe and a huge potential of RES in the overall region that could, with new transits from Ukraine, Turkey, Romania and Bulgaria, make congestions on the above mentioned directions.

Under umbrella of USAID South East Cooperation Initiative Regional (SECI) Transmission Planning Working Group prepared this project to analyze the capability of SEE transmission grid to handle various cases of generation dispatch identified in the market study, recognize network congestions and suggest corresponding infrastructure strengthening. Market and network calculations in in this study are applied iteratively. Market analyzes provided perspective generation and load patterns and consequential exchange patterns. The most critical patterns with highest consumption, highest RES penetration and lowest consumption are analyzed as selected cases for network studies.

This project is divided in two phases: 1) preparation of common market model, 2) SEE market perspectives study. In the first phase relevant input data were collected, clarified and verified.

The second phase is to assess perspective electricity market behavior in SEE region considering influence of generation development involving RES, markets integration and the subsequent needs for transmission investments.

To perform market analysis power systems of SEE region countries were modelled using electricity market simulation and optimization software PLEXOS. Starting with the data collected from TSOs, the following approach was adopted with regard to modelled countries:

- Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Kosovo, Macedonia, Montenegro, Romania and Serbia are modelled on plant-by-plant level of details,
- Greece, Hungary and Slovenia are aggregated per technology clusters (thermal by fuel type, hydro by type, RES by technology),
- Italy, Turkey and Central Europe region are modelled as external spot markets where the market clearing price series is insensitive to fluctuations of prices in SEE, constrained by transmission capacity.

The target year for the analyses is 2030 for which simulations were carried out on hourly basis. Considering the size of simulated system and the amount of collected data, each country was modelled as a single node to which all generators within the country were connected to. Nodes are connected by virtual transmission lines with maximum capacity equal to the nominal transfer capacities between the two countries.

Overall, market model includes 580 generating units in 12 countries in SEE region modelled with hourly demand for each country. The above mentioned number of generating units refers to 153 TPPs, 6 NPPs, 124 storage HPPs, 53 RoR HPPs and it is the most detailed electricity market model in the region, verified by all TSOs. In addition, for each country one equivalent wind and one equivalent solar power plants were modelled. Additional three external markets representing Italy, Turkey and Central Europe were modelled using simulated hourly price time series. Market model contains 28 cross-border lines and 4 submarine HVDC cables in total.

Impact of regional connections towards Italy was assessed by analyzing three scenarios, as shown on the following Figure:

- **Reference Case scenario**: with existing HVDC Greece-Italy,
- **Base Case scenario**: with existing HVDC Greece-Italy and HVDC Montenegro-Italy (under construction) and
- **Alternative Case scenario**: with existing HVDC Greece-Italy, HVDC Montenegro-Italy (under construction), HVDC Croatia-Italy and HVDC Albania-Italy.


*Figure 1: Illustration of different analyzed scenarios*

Reference Case scenario was created for purposes of comparison of Base and Alternative Case scenario results. Reference Case scenario only includes the existing HVDC cable Greece-Italy and thus it presents current regional interconnections with Italy. Base and Alternative Case scenario results are compared in terms of yearly electricity generation, average wholesale prices, net interchange, total transfer and cross-border loadings.

$CO_2$ emissions prices are also considered in market analyses and included in the optimization objective function. Assumption on $CO_2$ emissions prices is taken from TYNDP 2016 in the amount of 17 €/ton. Additional set of scenarios (Reference, Base, Alternative) without Carbon Cost was performed for evaluating the effect of $CO_2$ emissions prices.

Network analysis performed for the purposes of this Study, were based on Market Analysis snapshots. Based on Market Analysis results and perspective plans for commissioning HVDC links between SEE region and Italy, **Base Case** and **Alternative Case** scenarios were analyzed:

For both scenarios, three study cases were defined based on Market Analysis results, and analyzed in details:

1) Highest consumption in SEE region (18$^{th}$ of December 2030, 18:00h)
2) Highest RES penetration in SEE region (9$^{th}$ of December 2030, 11:00h)
3) Lowest Consumption in SEE region (28$^{th}$ May 2030, 03:00h)

All scenarios were identified as the most critical in terms of transmission system security. For both scenarios and characteristic regimes, total of six network (load flow) models were created for the purpose of network analyzes. As a basis for model creation, SECI RTSM model for 2030 Winter Peak regime was used.

After initial calculations there were some differences between SECI RTSM 2030 Winter Peak model, which was based on individual TSO TYNDP's, and network models based on Market Analysis results, as shown on the following Figure. Initial analyzes have shown that for some countries, level of exchanges presumed in SECI RTSM model are different than the ones obtained from Market Analyzes, i.e.

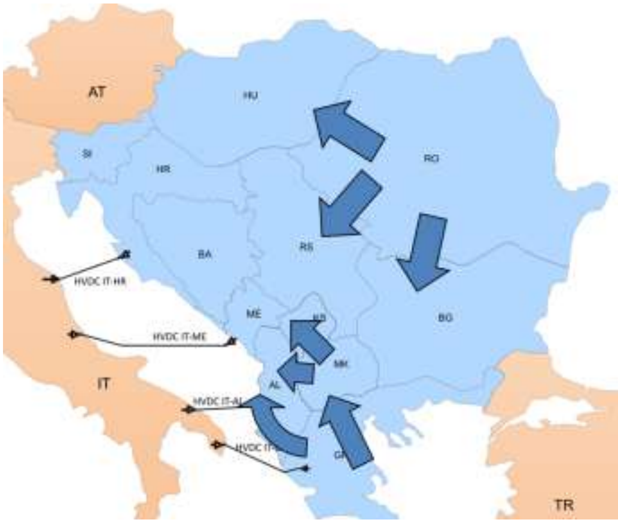
- For Albania, Montenegro, Serbia and Slovenia, market analysis have shown these countries are importers rather than exporters, as it is initially presumed
- For Greece and Macedonia, market analysis has shown these countries are exporters rather than importers, as it is initially presumed
- For other countries considered, initially planned exports or imports are in line with Market Analysis results, just with different total amounts

Clearly, planned generation investments in some regional countries in given timeframe will change existing country balances. Because of different exchange levels, load flow patterns are also different. When compared to initial SECI RTSM 2030 Winter Peak model, main differences in power exchanges are following:

- Flows from Hungary to Croatia are increased from 850 MW in Base Case, to 1150 MW in Alternative Case.
- Flows from Romania to Serbia are increased from 600 MW in Base Case to 1150 MW in Alternative Case
- Flows from Greece to Albania are increased from 600 MW in Base Case to 800 MW in Alternative Case
- Flows from Bosnia and Herzegovina towards Croatia are decreased by 500 MW in Base Case and increased by 500 MW in Alternative Case.
- Flows in all analyzed regimes are in direction from Bosnia and Herzegovina to Montenegro, while it is opposite in SECI RTSM model
- Flows in all analyzed regimes are in direction from Greece to Macedonia, while it is opposite in SECI RTSM model
- Finally, the biggest cross-border flow differences between SECI RTSM model and models based on market studies are shown on the following two Figure 149s.

For both scenarios and characteristic regimes, load flow calculation, voltage profile assessment and (n-1) contingency analysis were carried out. Also, for significant planned projects in the region, TOOT analysis was additionally conducted, with the aim of evaluating their influence on overall security of the transmission network in SEE region, in market coupled conditions.

For all **Base Case** regimes, it was generally concluded that market coupling in SEE region introduced changes in load flow patterns. Changes in power flows in transmission networks of the SEE region did not lead to overloadings in case when all elements are in operation. In such network topology conditions, voltage levels were in permitted ranges for Highest Consumption and Highest RES penetration regimes. For Lowest Consumption regime, in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initially unfeasibly high values of voltages.





**Base Case** **Alternative Case**

*Figure 2: The biggest cross-border flow differences between SECI RTSM model and models based on market studies*

Market simulations for Base Case scenarios have shown big congestions, with program flows reaching NTC values for many hours. Grid analyzes have shown that, in terms of (n-1) security criteria assessment, Highest RES penetration regime was identified as the most critical one for Base Case scenario. In this regime, outage of 400 kV OHL Portile de Fier (RO) – Resita (RO) causes overloading of 400 kV OHL Djerdap (RS) – Portile de Fier (RO). For other two regimes, Highest Consumption and Lowest Consumption, transmission networks in SEE region satisfy (n-1) security criteria.

Reported congestion on Serbia-Romania border in Highest RES penetration regime, is a strong signal that in order to introduce estimated or higher levels of NTCs for target year between these two countries, additional network reinforcements have to be implemented in order to enhance electricity trade and to support higher social welfare (lower overall energy price).

Sensitivity analysis, conducted for several planned project by applying TOOT methodology, has shown that:

- Project 400 kV OHL Pancevo (RS) – Resita (RO) has shown significant influence on (n-1) security criteria, in Highest Consumption and Highest RES penetration regimes.
- Project 400 kV OHL Banja Luka (BA) – Lika (HR) has shown small influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Bitola (MK) – Elbasan (AL) has shown small influence on (n-1) security criteria, in all analyzed regimes.
- Project new 400 kV interconnections RS-BA-ME has shown small influence on (n-1) security criteria, in all analyzed regimes.

For all **Alternative Case** regimes, it was generally concluded that market coupling in SEE region also introduces changes in load flow patterns. Changes in power flows in transmission networks of the SEE region did not lead to overloadings in cases when all elements are in operation. In such network topology conditions, voltage levels were in permitted ranges for Highest Consumption and

Highest RES penetration regimes. For Lowest Consumption regime, in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initial unfeasibly high values of voltages.

In terms of (n-1) security criteria assessment, Highest Consumption regime was identified as the most critical one for Alternative Case scenario. In this regime, outage of 400 kV OHL Konjsko (HR) – Mostar (BA) and outage of 220 kV Konjsko (HR) – Zakucac (HR) are causing overloading of 220 kV OHL Zakucac (HR) – Jablanica (BA). For other two regimes, Highest RES penetration and Lowest Consumption, transmission networks in SEE region satisfy (n-1) security criteria.

Reported congestion on Croatia-BiH border in Highest Consumption regime, is a strong signal that in order to introduce estimated or higher levels of NTCs for target year between these two countries, additional network reinforcement has to be implemented in order to enhance electricity trade and to support higher social welfare (lower overall energy price).

Sensitivity analysis, conducted for several planned project by applying TOOT methodology, has shown that:

- Project 400 kV OHL Pancevo (RS) – Resita (RO) has shown significant influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Banja Luka (BA) – Lika (HR) has shown less influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Bitola (MK) – Elbasan (AL) has shown influence on (n-1) security criteria in Highest Consumption regime.
- Project new 400 kV interconnections RS-BA-ME has shown influence on (n-1) security criteria in Lowest Consumption regime.

It should be pointed out that Base Case models are more comparable to SECI RTSM initial model, than Alternative Case model, because in Alternative Case models four HVDC links are in operation while in SECI RTSM and Base Case models, only two of them are in operation. Nevertheless, market based models show significant differences in load flow patterns when compared to model based on information from each TSO's National Development Plan. Main reasons of such differences are in first place:

- market integration
- different initial assumption of countries balances
- different RES production profile.

In parallel to network analyses, the main findings and concluding remarks resulting from the market analysis are given as follows.

Resulting wholesale prices, which are determined by marginal cost of generation and price on external markets, are comparable to actual market prices (due to input data on fuel costs, generation cost curves, generation investments and demand increase, etc.). In SEE region wholesale electricity prices are mainly harmonized, with certain variations (for example in Greece), what presents practically fully integrated SEE electricity market although several network congestions are still existing in the region.

Average market price in SEE region is increased by 1.60 €/MWh in Base Case and 3.75 €/MWh in Alternative Case compared to results of Reference Case which presents current regional interconnections with Italy, as shown on the following Figure. Thus, it can be concluded that additional HVDC links to Italy increase wholesale prices in SEE region up to 10%, but they also increase electricity generation and revenues.

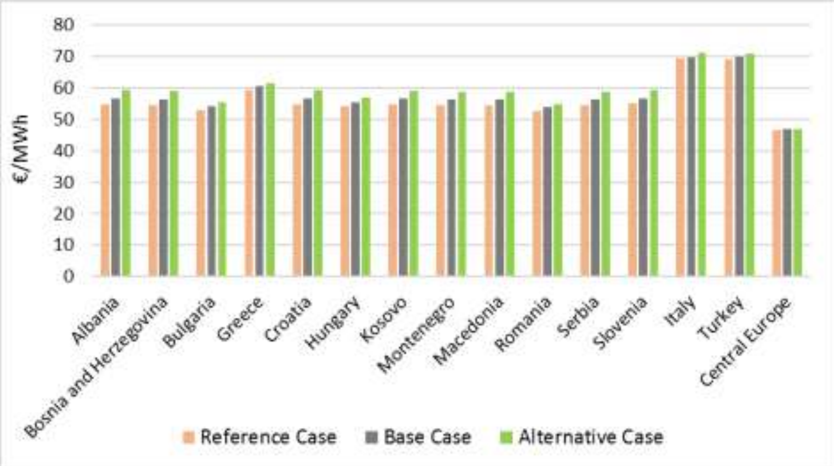



*Figure 3. Comparison of average wholesale prices*

Total generation in SEE is increased by 3.35 TWh (0.96%) in Base Case and 8.98 TWh (2.58%) in Alternative Case, compared to Reference Case scenario, as shown in the following Table. The most significant change occurs in Bosnia and Herzegovina – in Base Case yearly generation is increased by 1.53 TWh compared to Reference Case, while in Alternative Case by 3.51 TWh. Notable increases of electricity generation can be also observed in Bulgaria, Romania and Serbia.

*Table 1: Comparison of electricity generation in SEE region on country basis*

| Yearly generation (TWh) | AL | BA | BG | GR | HR | HU | KS | ME | MK | RO | RS | SI | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 10.75 | 15.59 | 50.99 | 51.11 | 15.06 | 40.04 | 12.07 | 4.57 | 10.42 | 88.44 | 35.18 | 14.31 | **348.53** |
| **Base Case** | 10.74 | 17.11 | 51.30 | 50.99 | 15.24 | 39.93 | 12.07 | 4.57 | 10.66 | 88.85 | 36.10 | 14.31 | **351.88** |
| **Change (TWh)** | -0.01 | 1.53 | 0.32 | -0.11 | 0.18 | -0.11 | 0.00 | 0.00 | 0.24 | 0.41 | 0.92 | 0.00 | **3.35** |
| **Change (%)** | -0.12 | 9.79 | 0.62 | -0.22 | 1.18 | -0.27 | 0.00 | -0.01 | 2.33 | 0.46 | 2.61 | 0.01 | **0.96** |
| **Alternative Case** | 10.79 | 19.09 | 51.61 | 51.89 | 15.52 | 40.21 | 12.06 | 4.66 | 11.04 | 89.36 | 36.95 | 14.32 | **357.50** |
| **Change (TWh)** | 0.04 | 3.51 | 0.62 | 0.78 | 0.45 | 0.17 | -0.01 | 0.10 | 0.62 | 0.92 | 1.77 | 0.01 | **8.98** |
| **Change (%)** | 0.36 | 22.50 | 1.22 | 1.53 | 3.02 | 0.43 | -0.11 | 2.09 | 5.99 | 1.04 | 5.03 | 0.04 | **2.58** |

Additional HVDC cables in Base and Alternative Case increase net interchange to Italy. Italy is a net importer and in Base Case scenario Italy net imports 5,214 GWh more than in Reference, while in Alternative 12,652 GWh more than in Reference Case. SEE region becomes a stronger net exporter in Base and Alternative Case. In Base Case net interchange of SEE region is 3,284 GWh higher than in Reference, while in Alternative it is 8,753 GWh higher than in Reference Case.

Effect of $CO_2$ emissions prices was evaluated in the additional set of scenarios without carbon cost. In all scenarios without carbon cost electricity generation is expectedly increased. In Base Case total SEE region generation is 14.49 TWh higher and 14.52 TWh in Alternative Case compared to main set of scenarios which include Carbon Cost. Since these scenarios do not include carbon cost, cost of generation is lower and thus market prices in SEE region are lower. Average wholesale price in SEE region is 5.60 €/MWh lower in Base Case and 3.84 €/MWh in Alternative Case in scenarios without carbon cost.

Regarding Network analysis, for identified congestions on borders between Romania and Serbia, and between Croatia and Bosnia and Herzegovina, it is recommended that additional infrastructure strengthening is considered in these regions, in order to enhance electricity trade and to support higher social welfare (lower overall energy price).

Also, as it was stated previously, in the process of model creation for Lowest Consumption regime, due to particularly high values of voltages, feasible solution could not be reached in first attempt. In order to get a feasible solution, i.e. to reach load flow calculation convergence, additional measures had to be implemented. Previously described problem in minimum loading regime justifies reactive power compensation studies which are on-going in the region of SEE.

The study has shown that market based results gave very different generation footprint in the region when compared to predictions of individual TSOs. Main reasons for such differences is in additional market coupling introduced different country balances, different generation schedules than the ones based on individual TSO experience and higher RES penetration per country.

Finally, in order to get a better understanding of market coupling influence on individual TSO operation, it was concluded that it is important to further proceed with grid and market investigations in order to properly evaluate benefits and consequences of market operation, optimize market performance, properly evaluate overall social welfare and gain more benefits of regional market integration for SEE region.

# 2 INTRODUCTION

The ultimate goal in today electricity business in Europe is market integration on pan-European level that will introduce transparency and competition between market players, incentives to clean energy development, as well as high quality of supply to the end customers. Transmission system planers are devoted on reaching these objectives. All planning efforts are focused on development such environment for smooth transition and coupling of national markets while securing reliable operation of transmission network. The main objective of transmission system planning is to ensure the development of an adequate transmission system which contributes to:

- Security of supply
  (Transmission grid ensures safe system operation and provides a high level of security of supply)
- Sustainability
  (Transmission grid allows for the integration of renewable energy sources RES)
- Competitiveness
  (Transmission grid facilitates grid access to all market participants and contributes to social welfare through internal market integration and harmonization)

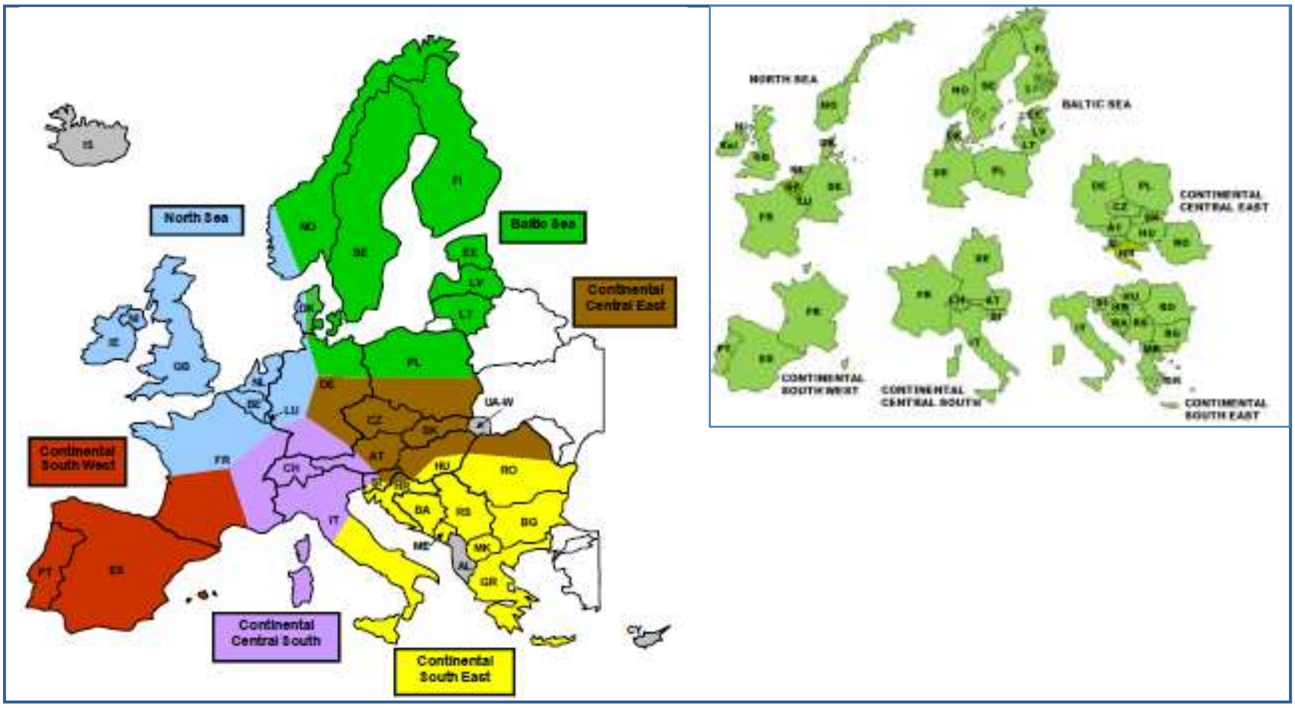



*Figure 4: Structure of six ENTSO-E planning regions*

Recent and on-going investigations on European level apply regional approach. For example, ENTSO-E planning process identify 6 regions (Figure 4) and runs in parallel several market studies at regional levels, in order to better adapt to specifics of every region on the one hand, and mutually challenge the models to derive more robust results. The variety of outcomes of market studies are presented in Regional Investment Plans. The simulations are derived from a single database (Pan European Market Modeling Database - PEMMDB) depicting the scenarios to ensure consistency between all six European regions.

Simplified pan-European simulation is firstly done, in order to provide input for boundary conditions of every region. Every regional group undertake more detailed regional market and network studies in order to explore every vision and perform the CBA assessment of the projects.

In South-East Europe (SEE)[2] there are uncertainties for the East-West and North-South transmission adequacy linked with the possible new undersea HVDC connections between SEE and Italy, the connection of Ukraine to the rest of the Europe and a huge potential of RES in the overall region that could, with new transits from Ukraine, Turkey, Romania and Bulgaria, make congestions on the above mentioned directions.

Investigation in this Study should go one step further in market analyses by applying wider outlook of the market integration. Challenges in the market evolution process that deserves further detailed analyzes are:

- Mutual influence of SEE and Italian electricity markets with focus on new HVDC connections between SEE and Italy
- Influence of Continental Central East region of Europe to the SEE electricity market
- Integration of renewable energy sources in SEE
- Perspective transmission corridors to support the electricity trading patterns across SEE

[2] SEE region in the scope of present project considers: AL, BA, BG, GR, HR, HU, KS, ME, MK, RO, RS, SI.

# 3 MARKET MODELLING DATABASE

The market analyses in this Study are performed by modelling the power systems of Southeast Europe countries using electricity market simulation and optimization software. The first step in that process was to develop a database of power generation and demand data for SEE countries including cross-border transmission capacities in the region.

Creation of SECI market modelling database for SEE region comprised the following activities:

- definition of relevant input data needed for the market analyses on the regional level, as well as to be detailed enough for internal TSO analyses,
- collection of existing input data from existing PSS/E models, TSOs, PEMDB and other available sources,
- clarification of missing input data and suggestions for solution (typical data etc., ENTSO-E PEMMDB data, GIS data),
- verification of common market model and
- decision on the market study methodology, future versions and format of common market models, as well as eventual common market software platform.

The following approach was considered in modelling of generation fleet:

- Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Kosovo, Macedonia, Montenegro, Romania and Serbia are represented on plant-by-plant level of details,
- Greece, Hungary and Slovenia are aggregated per technology clusters (equivalent power plants per technology cluster: thermal by fuel type, hydro by type, nuclear, RES),
- Turkey, Italy and Central Europe are modelled as spot markets (market price insensitive to fluctuations of prices in SEE; constrained by transmission capacity).

Technical and economic characteristic taken into consideration for analyzed generation capacities include:

1) for thermal power plants
    - general data (plant name, ownership, number of units, fuel type),
    - operational status – current state and target year per unit,
    - maximum net output power per unit,
    - minimum net output power per unit,
    - heat rates at maximum net output power per unit,
    - heat rates at minimum net output power per unit,
    - fuel cost per unit,
    - fixed O&M costs per unit,
    - variable O&M costs per unit,
    - outage rates (forced outage rate – FOR, maintenance outage rate - MOR) and maintenance periods per unit,
    - $CO_2$ emission factor per unit,
    - operational constraints (ramping limits, minimum up/down time) per unit,
    - must-run constraints per unit,

2) for hydro power plants
    - general data (plant name, ownership, number of units),
    - operational status – current state and target year,
    - plant type (run of river, storage (seasonal, weekly, daily), pump storage plant),
    - maximum net output power per unit,
    - minimum net output power per unit,
    - biological minimum production,
    - reservoir size,
    - maximum net output power in pumping mode per unit in case of PS power plants,
    - minimum net output power in pumping mode per unit in case of PS power plants,
    - average monthly inflows for storage plants,
    - average monthly generation for run of river plants,
    - yearly production,
3) for renewable energy sources
    - installed capacities (solar),
    - installed capacities (wind),
    - hourly capacity factor for target year (solar),
    - hourly capacity factor for target year (wind),
4) for demand
    - hourly load profile for target year,
5) for network constraints
    - defined network constraints for winter/autumn and summer/spring regimes: both current state and target year taking into account planned network reinforcements.

For all the modelled countries, the primary source of the data was provided by the national transmission system operators in the form of questionnaires. For the remaining unavailable data, other verified and publicly available official data was used along with internal consultant documents and estimates. Special care is taken to keep the consistency of the input dataset. Thus the data originated from ENTSO-E Market Modelling Database, REBIS GIS Study data and further internal consultant data, where applicable.

For Albania, the missing data for thermal characteristics for TPP Vlora and TPP Fier have been estimated according to ENTSO-E PEMMDB generic technology data. For new HPPs, the missing yearly to monthly inflow breakdown based on pattern from existing HPPs in Albania.

For Bosnia and Herzegovina, the missing data for TPPs Kakanj and Stanari have been estimated according to other lignite-fueled units in BA. The data not completely available such as fixed O&M costs have been estimated according to REBIS GIS study data and internal consultant databases.

For Bulgaria, the missing monthly inflow profile for HPP Aleko and HPP Pestera have been estimated according to REBIS GIS study data.

For Croatia, several of the new TPPs are planned and supposed to be built by 2030, thus their characteristics are still largely undefined. An expert assessment of all TPPs that are in the process of being planned and evaluated is performed. As a result, the most probable set of future TPPs envisaged to be online by 2030 is provided in the input data. The consultant internal databases are used for monthly hydro inflow profile. For the future HPPs, the hydro profile is estimated on the basis of similarity to existing hydrological conditions and internal consultant simulations.

For Kosovo, the missing data for thermal characteristics for new power plants have been estimated according to ENTSO-E PEMMDB data for new lignite plants.

For Macedonia, fixed O&M costs for TPP Bitola units 1-3 have been revised according to REBIS GIS study data. Hydro production and inflow profile of HPP Svetka Petka was estimated according on consultant internal database for regional projects.

For Montenegro, all relevant data is provided.

In the input data for the Romanian power system, there is a relatively large number (128) of HPP generating units, which mostly refer to relatively small HPPs, run-of-the-river or with weekly reservoirs. Hence, the Romanian HPPs were aggregated according to the river basin they are situated. This is an acceptable simplification, especially considering the simulations will be performed for a large area and with many larger hydro power plants in the region.

For Serbia, $CO_2$ emission coefficients have been estimated according to ENTSO-E PEMMDB data, while monthly generation profile for Bistrica, Uvac, Kokin Brod, Pirot, Vrla 1,2,3,4 is modelled according to REBIS GIS study data.

In Hungarian power system, the NPP Pakš is the most dominant power plant for the simulations, since it is expected that further 2,400 MW in the planned generators 5 and 6 are operating in 2030 so the total installed capacity amounts to 4,400 MW. The other TPPs in Hungary are considered in an aggregated manner, based on their fuel. Furthermore, while Hungary has virtually no hydro production, there is a somewhat significant biomass production expected – 242 MW by 2030.

Within the observed input dataset, one can observe some legacy of former Yugoslavian power system. Namely, there are two power plants situated in and operated by one country, while partially producing energy for another country. Such arrangements date back to the investments in these power plants. Specifically, this is the case of HPP Dubrovnik and NPP Krško. HPP Dubrovnik engine room is located in Croatia, while its reservoir is almost completely located in Bosnia and Herzegovina (a part of the reservoir is in Montenegro). It is normally considered that one of two generators in HPP Dubrovnik produces electricity for Croatia, and the other for Bosnia and Herzegovina. In case of NPP Krško, it is co-owned (50/50) by Croatian HEP and Slovenian Gen-Energija. The situation is fairly similar to the one in HPP Dubrovnik: half of the production satisfies Croatian demand, and the other half is delivered to customers in Slovenia. In some cases, these generators are even considered as (administratively) belonging to the power system of the country where they are not physically located. For instance, the Croatian power company HEP Group typically considers only one of the two generators in HPP Dubrovnik (108 MW) in their official reports, while the other generator (also 108 MW) is considered a part of B&H power system. However, for the sake of consistency in modelling, within this study a methodology typically adopted by Eurostat and other relevant statistical bodies is used:

- the power plant is considered as a part of the state where it is physically located,
- if there are any special arrangements between the two countries, these are considered as "special conditions export arrangements".

The idea behind this approach is to create the model that respects the actual situation as realistically as possible. For the power to be delivered across the border, a part of the cross-border capacities has to be allocated and this type of modelling respects that. For this reason, the NPP Krško is entirely considered as a part of Slovenian power system, and HPP Dubrovnik as a part of Croatian power system.

For wind power in Croatia, Bosnia and Herzegovina and Slovenia, the data previously collected by EIHP was used to simulate the hourly time series of wind during the year. This simulated data is based on wind resource analyses for these countries, and reflects the actual characteristics and variability of the wind recourse. The data are also considering already existing wind power plants, as well as the best prospective locations for the future wind power plants. For the stated and other countries, consistent capacity time series was used in the simulation.

With regard to solar data for all countries a consistent simulation was used, taking into account the geographic location specifics to estimate the energy yield from the solar power plants. Total installed capacities in 2030 are based on data received in questionnaires from TSOs, except for Montenegro. Although no data on solar capacities is received from Montenegrin TSO, it is assumed Montenegro will have 20 MW of installed capacity in solar, what is conservative assumption on installed solar capacity by 2030, considering solar capacities in other neighboring countries.

To maintain consistency, the hourly load data for all countries has been modelled according to ENTSO-E market modelling database (i.e. database for TYNDP). Vision 1 for 2030 from TYNDP 2014 was used for forecasted demand for all modelled countries, except for Greece. Greek demand according to the TYNDP 2014 was forecasted to be 75.20 TWh in 2030 what seemed too high and resulted in some strange results for annual imports, unserved energy and hours with congestions in the first market simulation runs. Thus, Greek demand was reviewed and adjusted according to the TYNDP 2016 Vision 1 for 2030.

Further details on input data regarding demand, generation capacities and network constraints per modelled country are provided in the respective following sections.

## 3.1 Albania

Forecasted consumption in Albania is at a level of 10.79 TWh in 2030. Observed peak load is 2,158 MW, with load factor of 57%. The highest consumption is observed in winter months (December and January), while the lowest consumption is present in mid spring and autumn months (especially in September), as can be seen in the following figures.

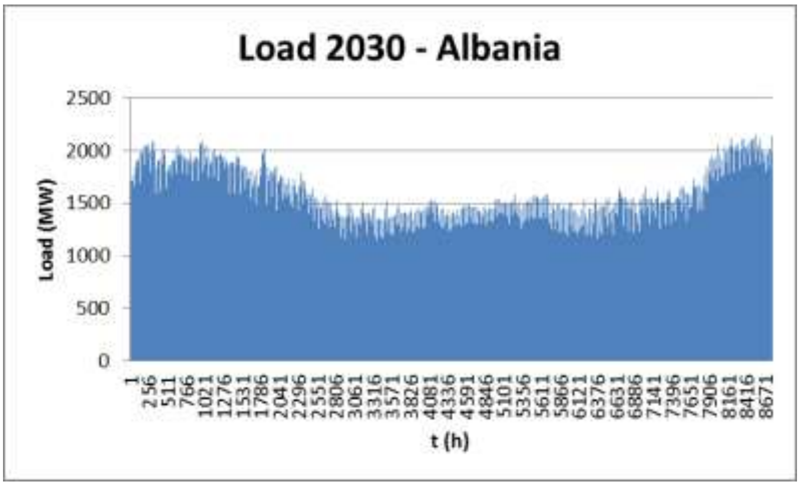



*Figure 5: Load profile 2030 – Albania*


*Figure 6: Monthly load 2030 – Albania*

Regarding generation capacities, in 2030 Albania will be still highly dependable on hydro production, with 80% of installed capacities in hydro generation. Installed capacity of 300 MW or 7% share is foreseen for renewable generation (wind, solar), while thermal generation is present with 13% share from gas fired units. Table 2 and Figure 7 provide details on Albanian installed capacities in 2030.

*Table 2: Installed capacities per technology (2030) – Albania*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-gas | 500 |
| Hydro | 3156 |
| Wind | 200 |
| Solar | 100 |

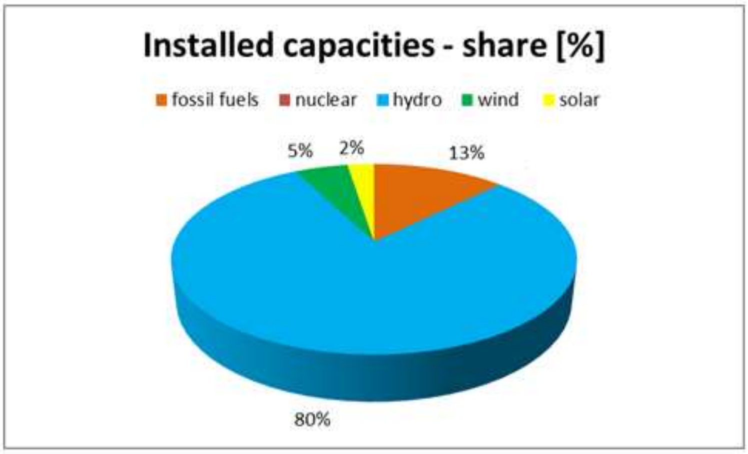



*Figure 7: Installed capacity per fuel type – Albania*

In terms of network constraints highest impact for Albania till 2030 will be commissioning of Bitola - Elbasan line which would directly connect Albania and Macedonia. In the alternative scenario of the study commissioning of additional HVDC link between Albania and Italy is analyzed. Assumed NTC value for this connection is 1,000 MW.

| NTC YEAR | 2015 | 2014 | 2020 | 2020 | 2025 | 2025 | 2030 | 2030 | Data source for current state | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | Win/Aut | Sum/Spr | Win/Aut | Sum/Spr | | | |
| KS - AL | 250 | 0 | 650 | 610 | 650 | 610 | 650 | 610 | ENTSO-E Transparency from July 2015 | EKC, TYNDP 2014, RgIP CSE 2014 | Project 147: Tirana(AL) - Pristina (KS) expected in 2016. After KOSTT will sign interconnection agreement with |
| AL - KS | 250 | 0 | 650 | 610 | 650 | 610 | 650 | 610 | | | |
| RS - AL | 0 | 210 | 0 | 0 | 0 | 0 | 0 | 0 | EMS, ENTSO-E Transparency | EKC, TYNDP 2014, RgIP CSE 2014 | After KOSTT will sign interconnection agreement with ENTSO/E expected in 2015 |
| Al - RS | 0 | 210 | 0 | 0 | 0 | 0 | 0 | 0 | | | |
| AL - ME | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | CGES | EKC, CGES | |
| ME - AL | 400 | 400 | 400 | 400 | 400 | 400 | 400 | 400 | | | |
| AL - GR | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | ADMIE, ENTSO-E Transparency | EKC | |
| GR - AL | 250 | 250 | 250 | 250 | 250 | 250 | 250 | 250 | | | |
| AL - MK | 0 | 0 | 400 | 400 | 400 | 400 | 400 | 400 | / | EKC | Project 147/239: 400 kV Bitola - Elbasan, expected after 2017, source of NTC values: Interconnection study Bitola-Elbasan, EKC, 2012 |
| MK - AL | 0 | 0 | 600 | 600 | 600 | 600 | 600 | 600 | | | |

*Figure 8: Network constraints – Albania*

## 3.2 Bosnia and Herzegovina

Considering the relatively low levels of the demand in Bosnia and Herzegovina at the moment, it is expected that the demand will grow somewhat. Bosnia and Herzegovina will most probably remain a net exporter of electric energy, however. The peak load in Bosnia and Herzegovina in 2030 is expected to be 2,894 MW, according to the Vision 1 of TYNDP 2014, with the minimum load expected to be about 1,200 MW. Total consumption is expected to be 16.46 TWh in 2030, with load factor 65%.

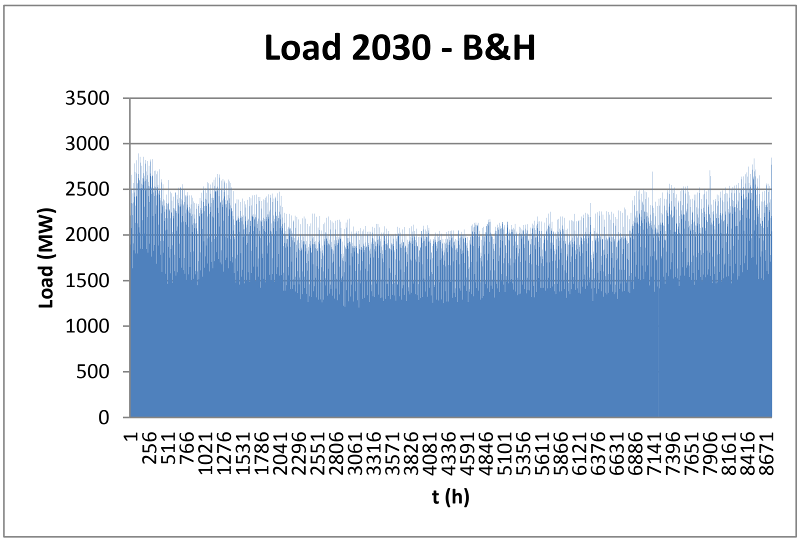



*Figure 9: Load profile 2030 – Bosnia and Herzegovina*

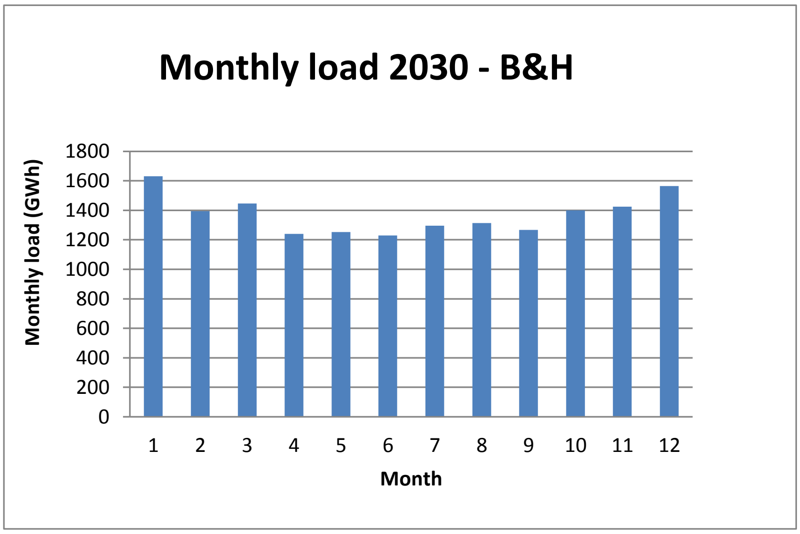



*Figure 10: Monthly load 2030 – Bosnia and Herzegovina*

Commissioning of several new generating units is expected in the following 15 years (2015-2030). With regard to the Bosnia and Herzegovina TPPs, they are exclusively dominated by locally sourced coal-fired power plants. For this reason, it is not expected that any new gas-fired TPPs will be built.

As can be seen in Table 3 and Figure 11, Bosnia and Herzegovina has significant hydro resources, as well – the HPPs share is almost the same as the TPPs. As it has been already commented in the introductory chapter, the above figures do not include the HPP Dubrovnik generator: given that the HPP Dubrovnik (and future HPP Dubrovnik 2) engine room is located in Croatia, these are considered as a part of the Croatian power system.

A notable share of wind is related to Bosnia and Herzegovina's significant wind resource, which by 2015 has not been tapped at all. However, by 2030 one can expect 640 MW of wind power to be online. Previous EIHP studies and simulations show that this has a significant effect on B&H's power system, due to a large share of lignite-fired thermal power plants.

*Table 3: Installed capacities per technology (2030) – Bosnia and Herzegovina*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 2465 |
| Hydro | 2273 |
| Wind | 640 |
| Solar | 10 |

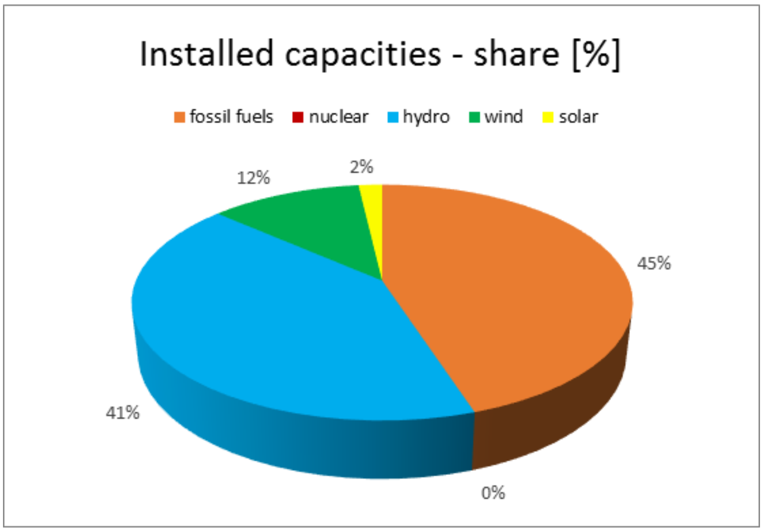



*Figure 11: Installed capacity per fuel type – Bosnia and Herzegovina*

By 2030, the situation on Bosnia and Herzegovina interconnections with neighboring countries will improve significantly regarding the nominal transmission capacity on almost all interconnections, as can be seen from the following figure.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| RS - BA | 600 | 500 | 1200 | 1850 | EMS, ENTSO-E Transparency | EKC, EMS, CGES, NOS BIH, TYNDP 2014, RgIP CSE 2014 | Regional study EKC: 2018: Conf2: Visegrad-B.Basta, B.Basta-Pljevlja, Brezna-B.Bijela 2023: Conf4: Visegrad-B.Basta, B.Basta-(Bistrica)-Pljevlja, Brezna-B.Bijela, Visegrad-(Pljevlja)-Bistrica |
| BA - RS | 500 | 500 | 1000 | 1700 | | | |
| BA - ME | 500 | 500 | 1050 | 1500 | CGES, NOS BiH | | |
| ME - BA | 400 | 450 | 1750 | 1400 | | | |
| HR - BA | 700 | 700 | 1200 | 1200 | NOS BiH, ENTSO-E Transparency | EKC, TYNDP 2014, RgIP CSE 2014 | Project 136: 400 kV OHL B.Luka (BA) - Lika (HR), expected in 2021, GTC increase of 500 |
| BA - HR | 750 | 550 | 1250 | 1050 | | | |

*Figure 12: Network constraints – Bosnia and Herzegovina*

## 3.3 Bulgaria

Forecasted consumption in Bulgaria is at a level of 38.79 TWh in 2030. Observed peak load is 7,036 MW, with load factor of 63%. Highest monthly consumption is observed in the end and at the beginning of the year, while lowest consumption is present in spring months and September.

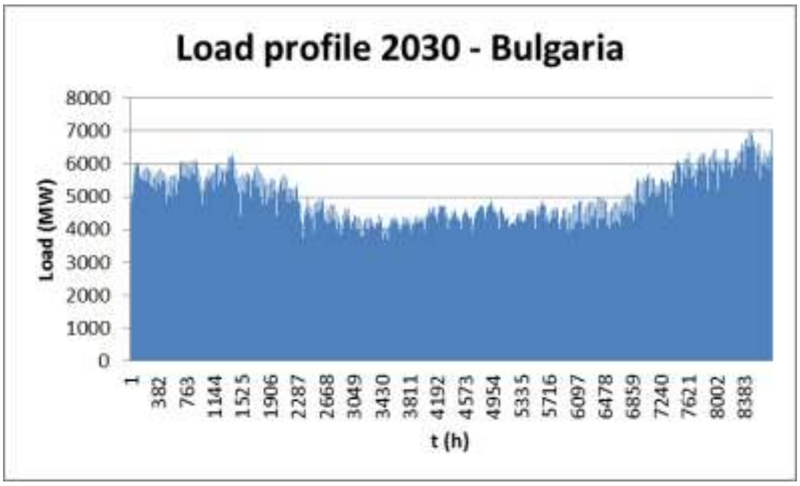



*Figure 13: Load profile 2030 – Bulgaria*

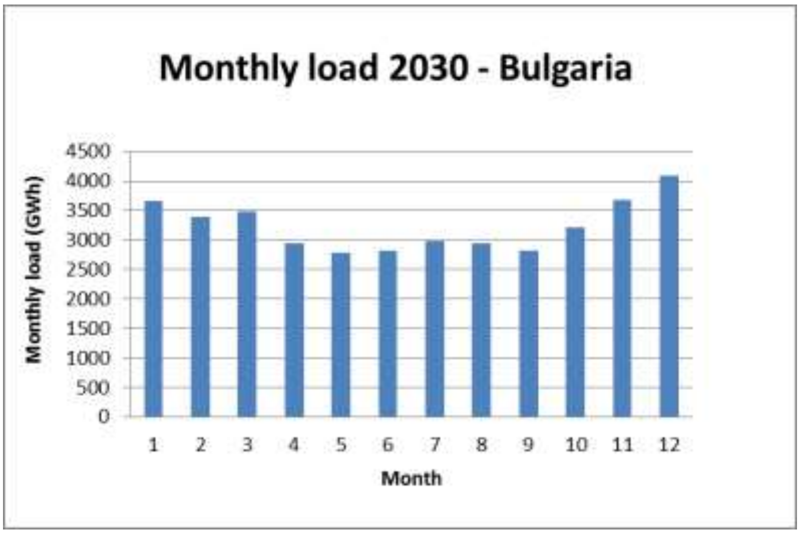



*Figure 14: Monthly load 2030 – Bulgaria*

In 2030 Bulgaria has highly diversified production mix. Around 55% of installed capacities is in thermal power plants, most of them base load plants (nuclear, lignite, hard coal). Installed capacities in renewable generation will rise up to 3,400 MW in wind and solar in 2030, while hydro generation will account a one fifth of installed capacities.

*Table 4: Installed capacities per technology (2030) – Bulgaria*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 3216 |
| Thermal-hard coal | 1263 |
| Thermal-gas | 784 |
| Thermal-nuclear | 2080 |
| Hydro | 2609 |
| Wind | 1600 |
| Solar | 1800 |

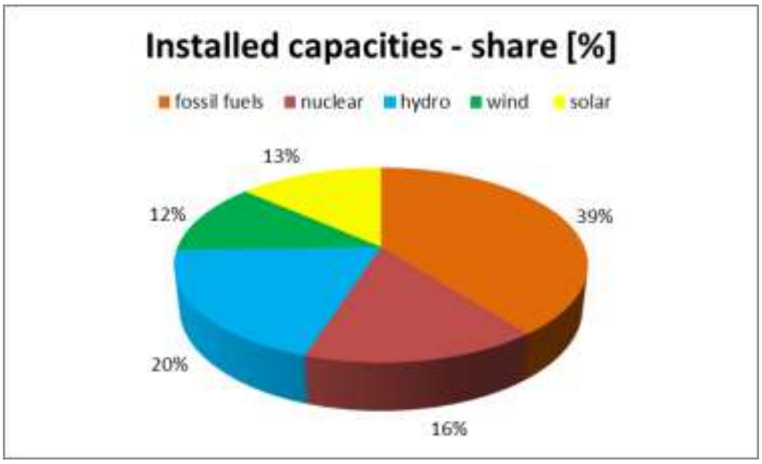



*Figure 15: Installed capacity per fuel type – Bulgaria*

In terms of network constraints substantial increase of NTC values for Bulgaria is expected comparing to the current state. NTC values at the border with Romania were revised according to the stated data source, because there was a significant difference in winter and summer regimes (in summer regime there were 600 MW higher NTC values) in the originally received input data.

| NTC YEAR | 2015 | 2014 | | 2030 | 2030 | | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|---|---|
| Season | Win | Sum | | Win/Aut | Sum/Spr | | | | |
| BG - RS | 300 | 350 | | 800 | 850 | | EMS, ESO, ENTSO-E Transparency | EKC based on TYNDP 2014 and RgIP CSE 2014 | NTC increase of 500 MW |
| RS - BG | 200 | 250 | | 700 | 750 | | | | |
| BG - MK | 200 | 200 | | 600 | 600 | | ESO 2015/14 | EKC | Calculated in previous studies by EKC |
| MK - BG | 100 | 100 | | 500 | 500 | | | | |
| RO - BG | 200 | 200 | | 1500 | 1400 | | TEL web - Transparency | 2020 - SOAF 2015 | |
| BG - RO | 300 | 350 | | 1400 | 1400 | | | 2030 - TYNDP2016 | |
| BG - GR | 600 | 600 | | 850 | 750 | | ESO 2015/14 | EKC | Calculated in previous studies by EKC |
| GR - BG | 400 | 400 | | 1000 | 1000 | | | | |
| BG - TR | 366 | 366 | | 867 | 734 | | ESO, TEIAS 2015/14 | EKC | Calculated in previous studies by EKC |
| TR - BG | 266 | 266 | | 934 | 800 | | | | |

*Figure 16: Network constraints – Bulgaria*

## 3.4 Greece

In Greece consumption in 2030 is at a level of 75.20 TWh, according to the TYNDP 2014. Forecasted consumption seemed too high and resulted in some strange results for annual imports, unserved energy and hours with congestions in the first market simulation runs. Thus, Greek demand was reviewed and adjusted according to the TYNDP 2016 Vision 1 for 2030, which foresees Greek annual consumption at the amount of 60.56 TWh in 2030. Observed peak load is 11,361 MW, with load factor of 61%. Monthly consumption ratio is well balanced, with highest values observed in summer season from June till August.

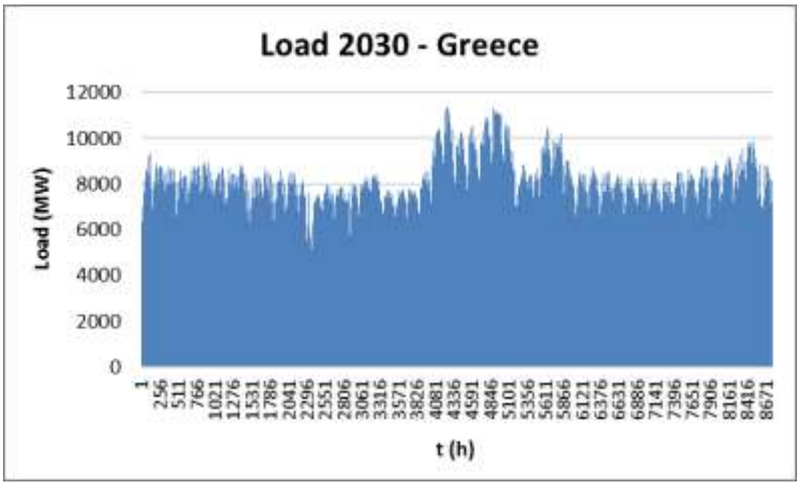



*Figure 17: Load profile 2030 – Greece*

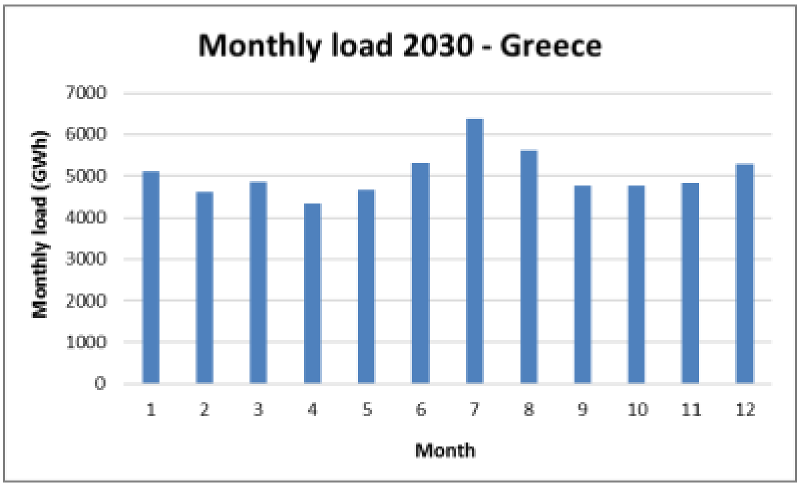



*Figure 18: Monthly load 2030 – Greece*

In 2030 Greece has highly diversified production mix. With 6,200 MW of installed generation in wind generation and 4,000 MW in solar generation, the largest renewable generation fleet in observed region is present in Greece. This value of renewable generation accounts for 41% of total installed capacities in Greece. Thermal power plants comprise for 41% of total installed capacities, with most of them being gas fired plants.

*Table 5: Installed capacities per technology (2030) – Greece*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 2856 |
| Thermal-gas | 7258 |
| Hydro | 4526 |
| Wind | 6200 |
| Solar | 4000 |

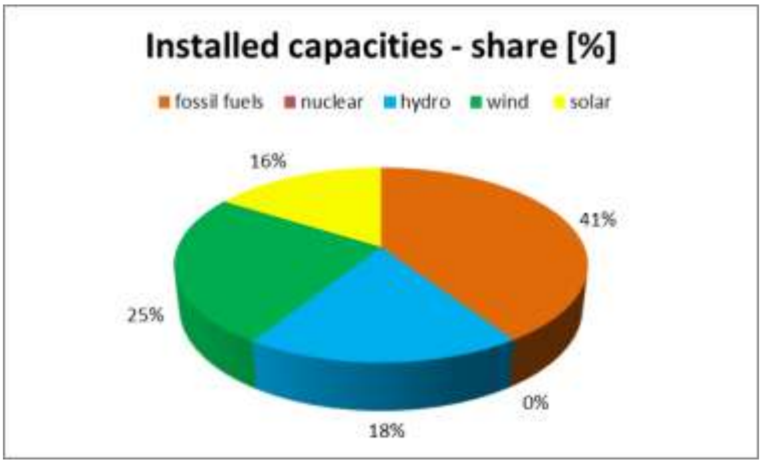



*Figure 19: Installed capacity per fuel type – Greece*

Network constraints are presented in the following figure. Except for the transmission lines listed in the Figure 20, market model also includes HVDC Greece-Italy with 500 MW of maximum flow in both directions.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| AL - GR | 250 | 250 | 250 | 250 | ADMIE, ENTSO-E Transparency | EKC | |
| GR - AL | 250 | 250 | 250 | 250 | | | |
| MK - GR | 300 | 370 | 650 | 1000 | ENTSO-E Transparency, MEPSO, ADMIE | EKC | Calculated in previous studies by EKC |
| GR - MK | 350 | 300 | 650 | 1000 | | | |
| BG - GR | 600 | 600 | 850 | 750 | ESO 2015/14 | EKC | Calculated in previous studies by EKC |
| GR - BG | 400 | 400 | 1000 | 1000 | | | |
| GR - TR | 184 | 200 | 433 | 366 | Based on 65%:35% ratio (BG/GR) of total NTC towards Turkey | EKC | |
| TR - GR | 134 | 143 | 466 | 400 | | | |

*Figure 20: Network constraints – Greece*

## 3.5 Croatia

In the Croatian power system, annual consumption is expected to be 22 TWh in 2030, with the peak load slightly below 4,000 MW and the minimum load of around 1,400 MW. From the pattern of monthly loads in Croatian power system, it is obvious that the air conditioning (cooling) usage in hottest summer months has a significant impact. For this reason, July and August are significantly higher in energy usage than June and September.

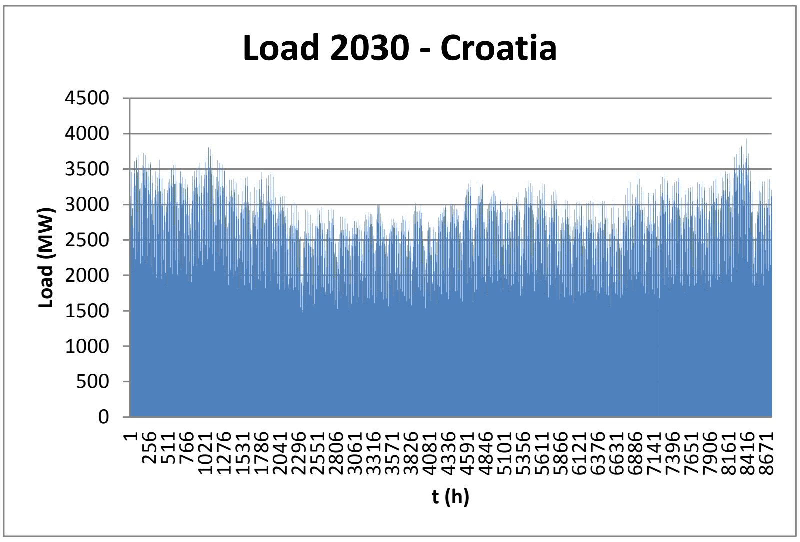



*Figure 21: Load profile 2030 – Croatia*

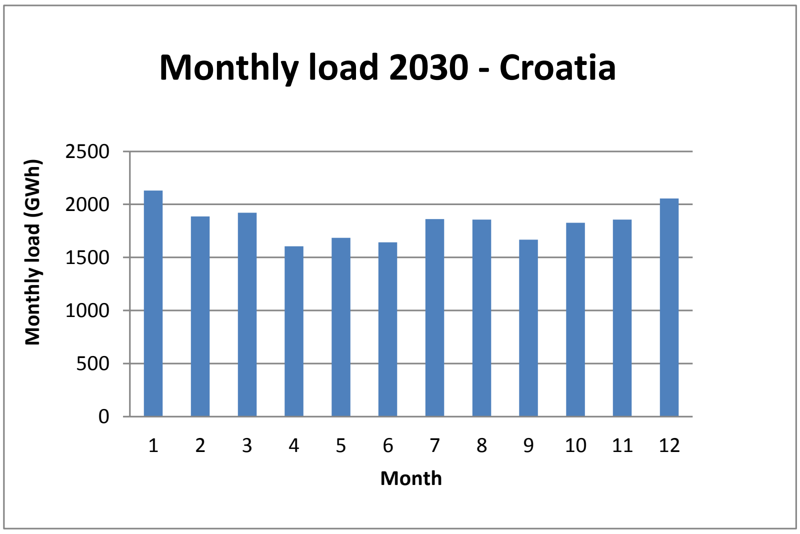



*Figure 22: Monthly load 2030 – Croatia*

The Croatian power system in 2030 will be dominated by hydro power plants. The TPPs in Croatia are expected to have about a third of installed capacity by then, and among the TPPs only the TPP Plomin in Istria region will run on coal, while the rest of the TPPs will exclusively run on natural gas and one TPP on fuel oil. Due to emissions regulations, several Croatian TPPs that are currently in operation in 2015 will be brought offline. Some of these TPPs are, in fact, expected to be shut off and preserved in an operational condition. Thus these TPPs will not be normally operating, but can be brought online if the need arises. For the sake of consistency in the model, these TPPs are not going to be included in the model, nor considered in the above figures, given that these TPPs are expected to operate solely in the case of large system disturbances.

As it has been commented in the introduction, while NPP Krško is partially owned by Croatian HEP and participates in satisfaction of Croatian demand, it is located and operated in Slovenia. For this reason, it is not included in the Croatian power system, but in Slovenian. Analogously, the HPP Dubrovnik and the planned HPP Dubrovnik 2 are considered as part of the Croatian power system for these simulations.

Besides the expected construction of 912 MW in several new HPPs in Croatia by 2030, some of the increase in the installed power of HPPs will come from reconditioning (upgrades) of existing generators – this may result in 20% increase in installed power for the larger HPPs in south of Croatia. For instance, the existing HPP Dubrovnik will be upgraded from 216 MW to 252 MW. For the future power plants, the inflow data is extrapolated from existing data based on hydrological similarity and geographic proximity.

Renewable energy will play a prominent role in Croatia: in 2015, around 400 MW of wind power is already online and by 2030 it is expected that the wind power connected to the grid will reach 1,300 MW, tapping the Croatian wind power resources with 17% share of installed power. Solar power is also significant with 200 MW of expected total installed capacity (3% share). For reasons of scale, Figure 23 does not show 18 MW in biomass-fired plant expected to be online in 2030.

*Table 6: Installed capacities per technology (2030) – Croatia*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-hard coal | 685 |
| Thermal-gas | 1718 |
| Thermal-fuel oil | 320 |
| Hydro | 3189 |
| Wind | 1300 |
| Solar | 200 |
| Biomass | 18 |

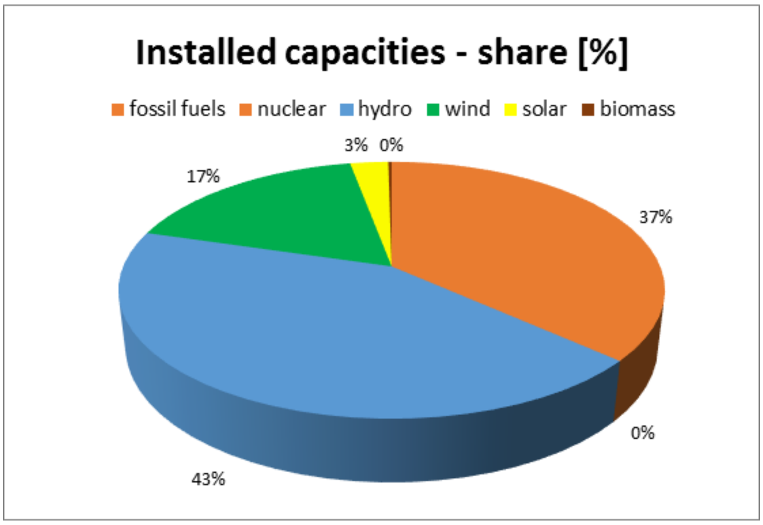



*Figure 23: Installed capacity per fuel type – Croatia*

With regard to network constraints, the most significant change will occur on the Croatia - Bosnia and Herzegovina interconnection where NTCs will increase after the construction of an overhead line from Banja Luka node in Bosnia and Herzegovina to Lika node in Croatia, increasing the NTC by 500 MW. In the alternative scenario of the market study commissioning of additional HVDC link between Croatia and Italy is analyzed. Assumed NTC value for this connection is 1,000 MW.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| RS - HR | 600 | 400 | 600 | 400 | EMS, ENTSO-E Transparency | EKC, EIHP | |
| HR - RS | 500 | 500 | 600 | 500 | | | |
| HR - BA | 700 | 700 | 1200 | 1200 | NOS BiH, ENTSO-E Transparency | EKC, TYNDP 2014, RgIP CSE 2014 | Project 136: 400 kV OHL B.Luka (BA) - Lika (HR), expected in 2021, GTC increase of 500 |
| BA - HR | 750 | 550 | 1250 | 1050 | | | |
| HR - HU | 1000 | 1000 | 1000 | 1000 | CAO, ENTSO-E Transparency | EIHP, EKC | |
| HU - HR | 1200 | 1200 | 1200 | 1200 | | | |
| HR - SI | 1500 | 1000 | 1500 | 1000 | CAO, ENTSO-E Transparency | EIHP, EKC | |
| SI - HR | 1500 | 1100 | 1500 | 1100 | | | |

*Figure 24: Network constraints – Croatia*

## 3.6 Hungary

In 2030, the peak load in Hungary is expected to reach 6,994 MW with minimum loads slightly below half this value, about 3,400 MW. The total consumption in 2030 is expected to amount to 47.20 TWh. Hourly load profile is depicted in Figure 25, while the monthly load profile shows a significant seasonality with April being significantly lower in consumption (Figure 26).

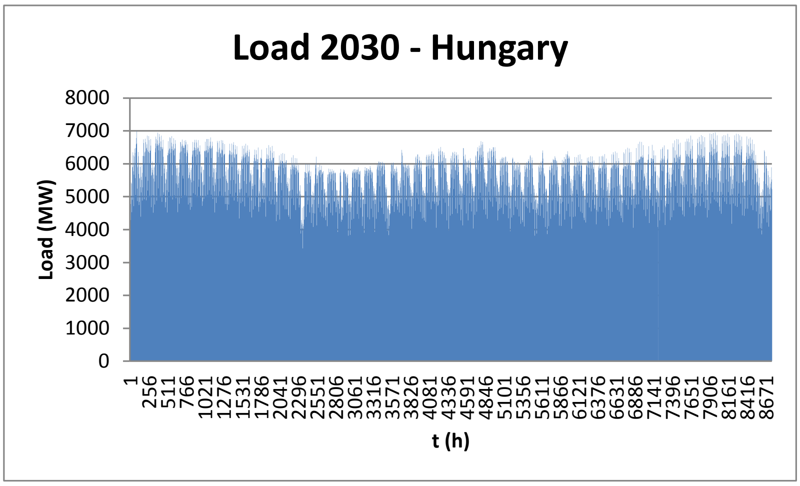



*Figure 25: Load profile 2030 – Hungary*

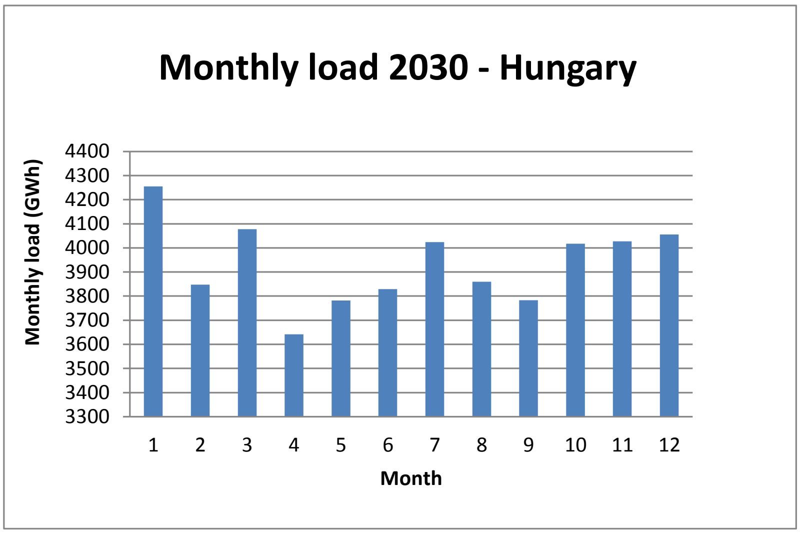



*Figure 26: Monthly load 2030 – Hungary*

The Hungarian power system is simulated with somewhat reduced level of details, i.e. power plants are aggregated by technology. In 2030 it is expected to be dominated by fossil-fuel TPPs, with almost half of the installed power in them. Further 42% will be in nuclear power, where NPP Pakš is expected to have 4,400 MW of installed power in 2030. The remaining 11% is shared between 800 MW of wind power, 242 MW of biomass TPPs and 75 MW of solar power.

*Table 7: Installed capacities per technology (2030) – Hungary*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 1064 |
| Thermal-gas | 3812 |
| Thermal-nuclear | 4400 |
| Wind | 800 |
| Solar | 75 |
| Biomass | 242 |

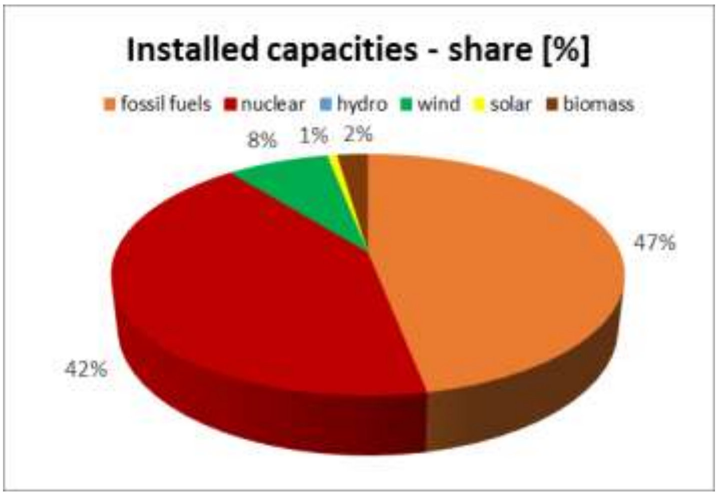



*Figure 27: Installed capacity per fuel type – Hungary*

With regard to interconnection capacities on the interconnections relevant for this study, they were expected to remain largely unchanged from 2015 to 2030, according to the originally received input data. However, NTC values at the border with Romania were revised according to the stated data source in Figure 28.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| RS - HU | 800 | 800 | 800 | 800 | EMS, ENTSO-E Transparency | | |
| HU - RS | 700 | 700 | 700 | 700 | | | |
| RO - HU | 700 | 700 | 1400 | 1300 | TEL web - Transparency | 2020 - SOAF 2015 | |
| HU - RO | 700 | 700 | 1300 | 1300 | | 2030 - TYNDP2016 | |
| HR - HU | 1000 | 1000 | 1000 | 1000 | CAO, ENTSO-E Transparency | | |
| HU - HR | 1200 | 1200 | 1200 | 1200 | | | |

*Figure 28: Network constraints – Hungary*

## 3.7 Kosovo

Forecasted consumption in Kosovo is at a level of 8.22 TWh in 2030, observed peak load is 1,630 MW, with load factor of 58%. Highest monthly consumption is observed in winter months (December and January), while the lowest consumption is present from May till September.

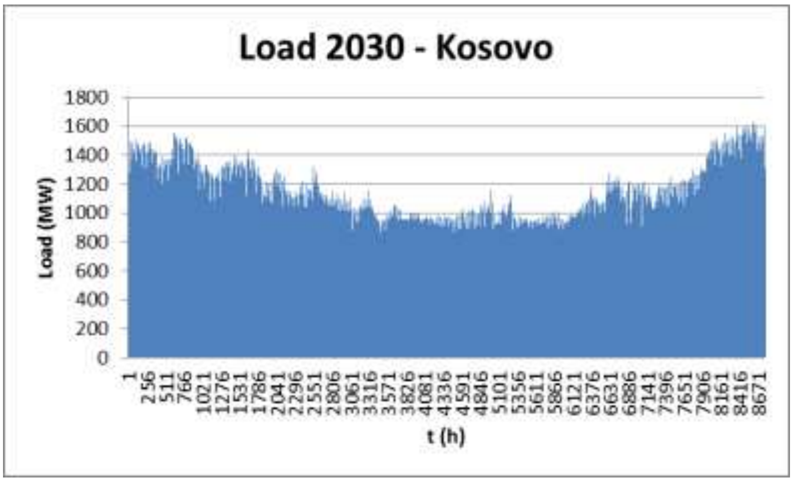



*Figure 29: Load profile 2030 – Kosovo*


*Figure 30: Monthly load 2030 – Kosovo*

In 2030 Kosovo is highly dependable on lignite fired plants with share of 89% of installed capacities. Around 9% or 160 MW of new installed capacities in RES generation is expected in the form of wind power plants (130 MW) and solar power plants (30 MW).

*Table 8: Installed capacities per technology (2030) – Kosovo*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 1658 |
| Hydro | 35 |
| Wind | 130 |
| Solar | 30 |

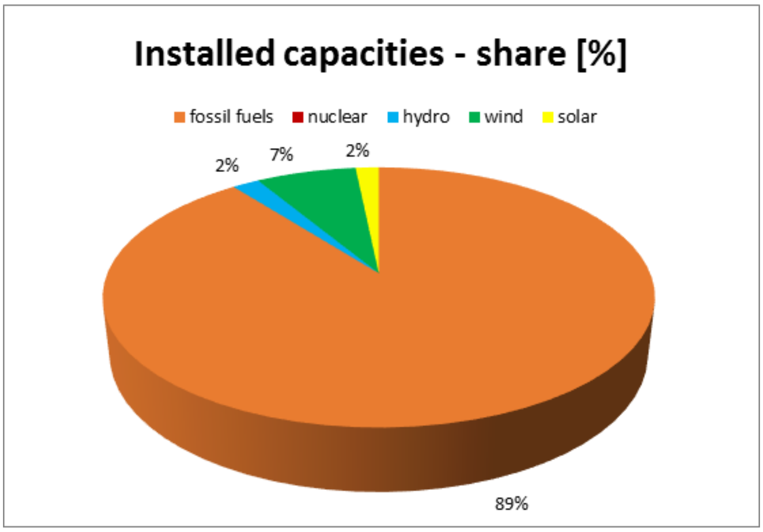



*Figure 31: Installed capacity per fuel type – Kosovo*

KOSTT is expected to sign an interconnection agreement with ENTSO-E during 2015, after which NTC values would be calculated by KOSTT for Kosovo area. Expected values for 2030 show the highest NTC at the border with Macedonia, while at other borders NTC varies from 300 MW up to 700 MW, with close figures in both winter and summer regime.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| KS - MK | 700 | 0 | 1100 | 1100 | ENTSO-E Transparency from July 2015 | EKC, TYNDP 2014, RgIP CSE 2014 | Project:Ferizaj2(Urosevac2) (KS) -Skopje 5(MK) expected inperiod 2026-2030, After KOSTT will sign interconnection agreement with ENTSO/E expected in 2015 |
| MK - KS | 300 | 0 | 900 | 900 | | | |
| RS- MK | 0 | 500 | 700 | 500 | EMS, ENTSO-E Transparency | EKC, TYNDP 2014, RgIP CSE 2014 | Project 147: Leskovac/Vranje(RS) - Stip (MK) expected in 2015/2016, GTC increase of 800 MW |
| MK - RS | 0 | 300 | 300 | 300 | | | |
| KS - AL | 250 | 0 | 650 | 610 | ENTSO-E Transparency from July 2015 | EKC, TYNDP 2014, RgIP CSE 2014 | Project 147: Tirana(AL) - Pristina (KS) expected in 2016. After KOSTT will sign |
| AL - KS | 250 | 0 | 650 | 610 | | | |
| RS_KS | 700 | 0 | 700 | 700 | Estimated. 'ENTSO-E Transparency from July 2015 | | After KOSTT will sign interconnection agreement with ENTSO/E expected in 2015 |
| KS-RS | 700 | 0 | 700 | 700 | | | |
| KS - ME | 450 | 0 | 450 | 450 | Estimated. 'ENTSO-E Transparency from July 2015 | EKC, EMS, CGES, NOS BIH, TYNDP 2014, RgIP CSE 2014 | Regional study EKC: 2018: Conf2: Visegrad-B.Basta, B.Basta-Pljevlja, Brezna-B.Bijela 2023: Conf4: Visegrad-B.Basta, B.Basta-(Bistrica)-Pljevlja, Brezna-B.Bijela, Visegrad-(Pljevlja)-Bistrica |
| ME - KS | 450 | 0 | 450 | 450 | | | |

*Figure 32: Network constraints – Kosovo*

## 3.8 Montenegro

Forecasted consumption in Montenegro is at a level of 5.39 TWh in 2030. Observed peak load is 972 MW, with load factor of 63%. In winter period (November - February) the highest monthly consumption above 500 GWh is observed, while in summer period (June - September), forecasted monthly load is below 400 GWh.

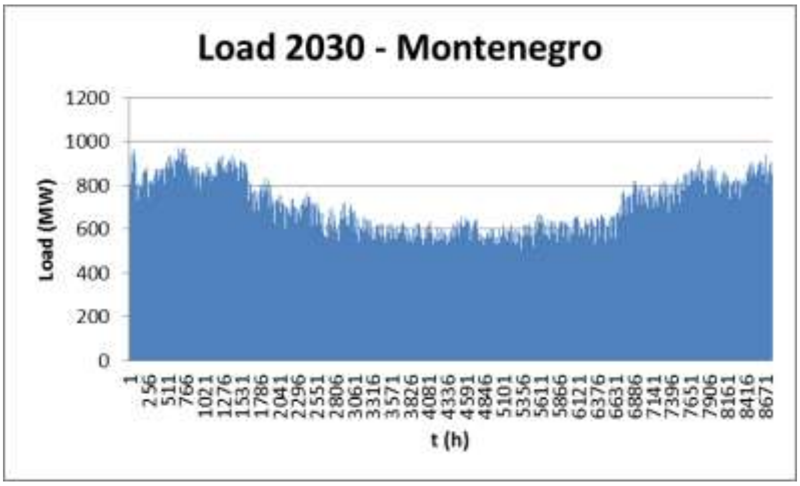



*Figure 33: Load profile 2030 – Montenegro*

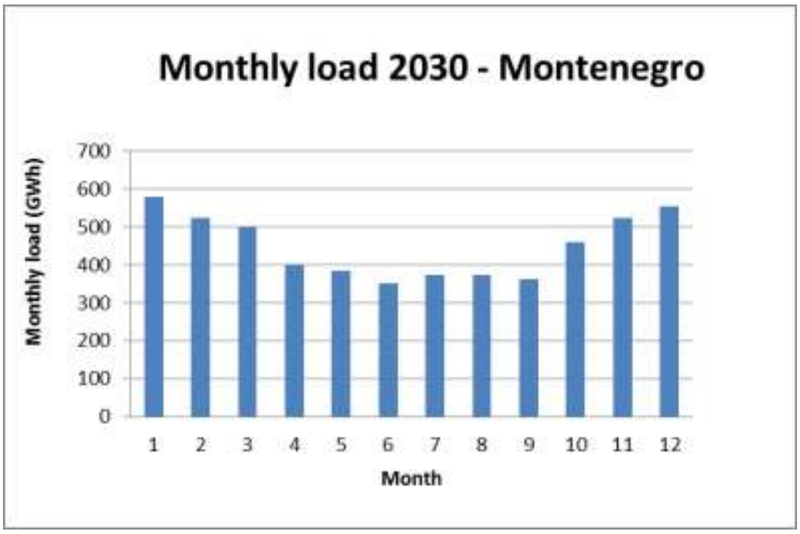



*Figure 34: Monthly load 2030 – Montenegro*

In 2030 the highest share of installed generation in Montenegro will be in hydro power plants. New thermal power plant Pljevlja would represent the only fossil fuel fired power plant, and commissioning of 190 MW of wind power plants is expected till 2030. Although no data on solar capacities is received from Montenegrin TSO, it is assumed Montenegro will have 20 MW of installed capacity in solar, what is an acceptable amount of installed capacity by 2030, especially considering solar capacities in other neighboring countries.

*Table 9: Installed capacities per technology (2030) – Montenegro*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 200 |
| Hydro | 1114 |
| Wind | 190 |
| Solar | 20 |

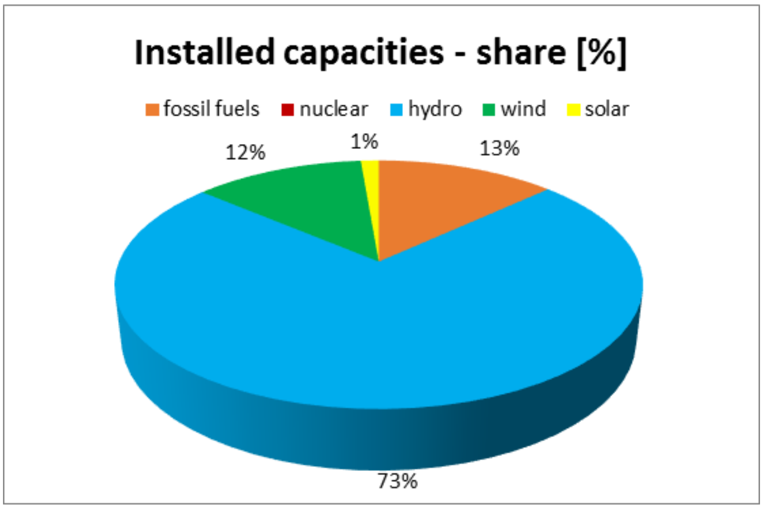



*Figure 35: Installed capacity per fuel type – Montenegro*

In terms of network constraints, two major network reinforcements will have a high impact on Montenegro. First of them, is the commissioning of HVDC link between Montenegro and Italy, which will directly connect the regional with Italian electricity market. The second major project, represents the new interconnection between Bosnia and Herzegovina, Montenegro and Serbia which will increase the NTC values at observed borders and facilitate the energy transit corridor towards Italy.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| KS - ME | 450 | 0 | 450 | 450 | Estimated. 'ENTSO-E Transparency from July 2015 | EKC, EMS, CGES, NOS BIH, TYNDP 2014, RgIP CSE 2014 | Regional study EKC: 2018: Conf2: Visegrad-B.Basta, B.Basta-Pljevlja, Brezna-B.Bijela 2023: Conf4: Visegrad-B.Basta, B.Basta-(Bistrica)-Pljevlja, Brezna-B.Bijela, Visegrad-(Pljevlja)-Bistrica |
| ME - KS | 450 | 0 | 450 | 450 | | | |
| RS - ME | 700 | 600 | 1050 | 1500 | CGES, EMS, ENTSO-E Transparency | | |
| ME -RS | 650 | 700 | 1200 | 1450 | | | |
| BA - ME | 500 | 500 | 1050 | 1500 | CGES, NOS BiH | | |
| ME - BA | 400 | 450 | 1750 | 1400 | | | |
| AL - ME | 400 | 400 | 400 | 400 | CGES | EKC, CGES | |
| ME - AL | 400 | 400 | 400 | 400 | | | |
| IT - ME | 0 | 0 | 1000 | 1000 | / | CGES, TERNA | Project 28: HVDC cable MON-ITA, expected in 2017, GTC increase of 1000 MW |
| ME - IT | 0 | 0 | 1000 | 1000 | | | |

*Figure 36: Network constraints – Montenegro*

## 3.9 Macedonia

Forecasted consumption in Macedonia is at a level of 11.29 TWh in 2030. Observed peak load is 2,081 MW, with load factor of 62%. The highest monthly consumption is observed in January, while the lowest consumption is present at the beginning and end of summer season (June and September).

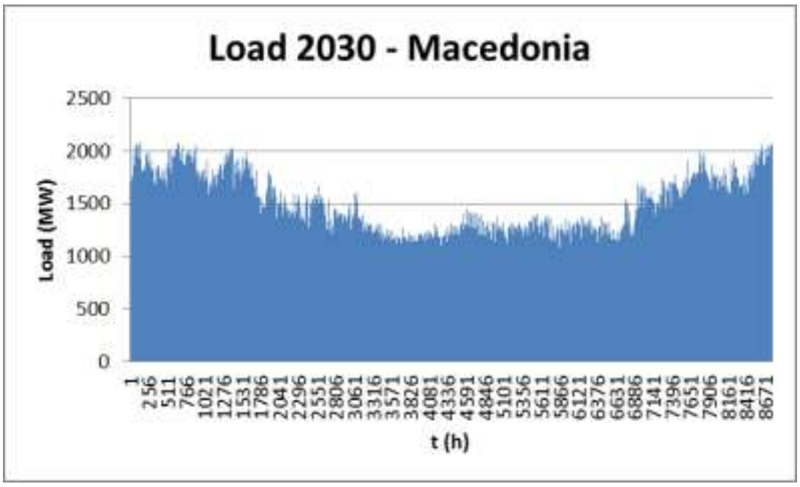



*Figure 37: Load profile 2030 – Macedonia*

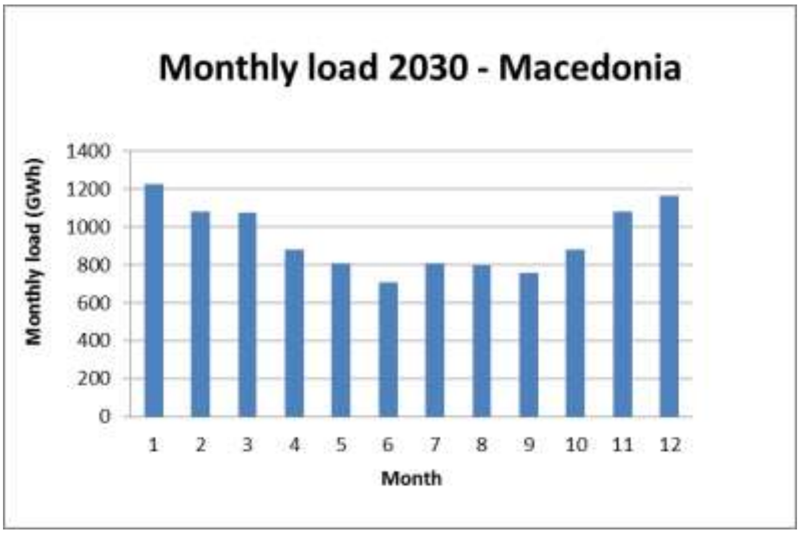



*Figure 38: Monthly load 2030 – Macedonia*

In 2030 Macedonia has well balanced hydro-thermal production mix, with 6% of renewable generation in wind and solar power plants. Base load plants (lignite, hard coal) will still represent the largest group of thermal units in terms of installed capacities, although most of the new commissioned thermal units will be gas fired units.

*Table 10: Installed capacities per technology (2030) – Macedonia*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 300 |
| Thermal-hard coal | 563 |
| Thermal-gas | 647 |
| Hydro | 1257 |
| Wind | 150 |
| Solar | 37 |

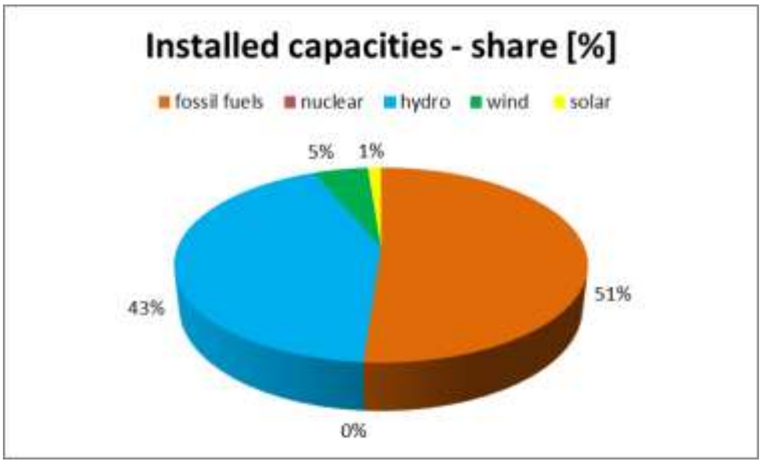



*Figure 39: Installed capacity per fuel type – Macedonia*

In terms of network constraints, several new network reinforcements are expected to strengthen the Macedonian interconnections and increase the NTC values. With commissioning of Bitola - Elbasan line, Macedonia will become directly connected to Albania, and increase the number of its capacity allocation borders comparing to the current state.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| KS - MK | 700 | 0 | 1100 | 1100 | ENTSO-E Transparency from July 2015 | EKC, TYNDP 2014, RgIP CSE 2014 | Project:Ferizaj2(Urosevac2) (KS) -Skopje 5(MK) expected inperiod 2026-2030, After KOSTT will sign interconnection agreement with ENTSO/E expected in 2015 |
| MK - KS | 300 | 0 | 900 | 900 | | | |
| RS- MK | 0 | 500 | 700 | 500 | EMS, ENTSO-E Transparency | EKC, TYNDP 2014, RgIP CSE 2014 | Project 147: Leskovac/Vranje(RS) - Stip (MK) expected in 2015/2016, GTC increase of 800 MW |
| MK - RS | 0 | 300 | 300 | 300 | | | |
| AL - MK | 0 | 0 | 400 | 400 | / | EKC | Project 147/239: 400 kV Bitola - Elbasan, expected after 2017, source of NTC values: Interconnection study Bitola-Elbasan, EKC, 2012 |
| MK - AL | 0 | 0 | 600 | 600 | | | |
| MK - GR | 300 | 370 | 650 | 1000 | ENTSO-E Transparency, MEPSO, ADMIE | EKC | Calculated in previous studies by EKC |
| GR - MK | 350 | 300 | 650 | 1000 | | | |
| BG - MK | 200 | 200 | 600 | 600 | ESO 2015/14 | EKC | Calculated in previous studies by EKC |
| MK - BG | 100 | 100 | 500 | 500 | | | |

*Figure 40: Network constraints – Macedonia*

## 3.10 Romania

The Romanian power system is larger than most of the modelled countries, both in terms of load and in terms of production. The maximum peak load in Romania is expected to surpass 11 GW, with the minimum load expected to be around 4,700 MW. Forecasted consumption in 2030 is at a level of 66.40 TWh in 2030, with load factor of 69%.

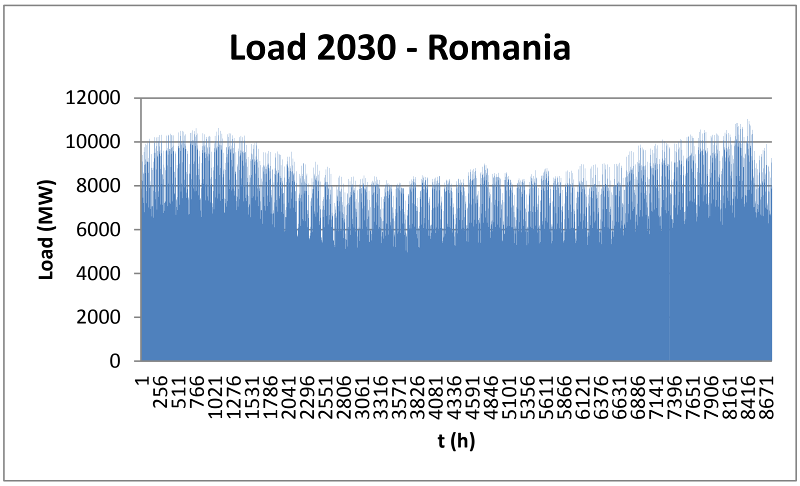



*Figure 41: Load profile 2030 – Romania*

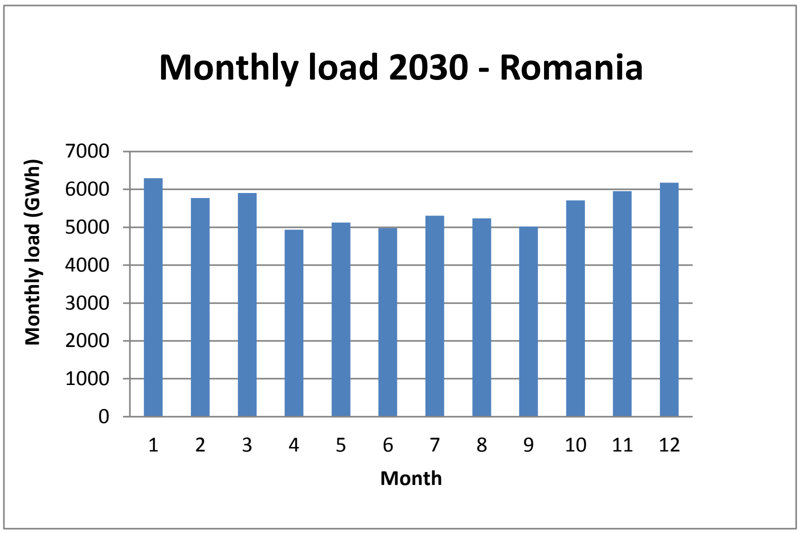



*Figure 42: Monthly load 2030 – Romania*

In Romania almost all technologies are present in the generation mix expected for 2030. Almost half of the installed power in Romanian power system will be in thermal power plants. The Romanian TPPs will run mostly on lignite and gas, about 4,500 MW each, but there will also be 915 MW of hard-coal fired TPPs. The nuclear power is prominent in Romanian generation mix with a share of 11% (2,856 MW). Hydropower will have an important share of 24%, but also renewables are expected to have a very significant role. Wind and solar power together have a 26% share in 2030. In wind power plants it is expected to be installed 4,200 MW (17% share) and the remaining 2,200 MW (9% share) will be in solar power plants.

*Table 11: Installed capacities per technology (2030) – Romania*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 4540 |
| Thermal-hard coal | 915 |
| Thermal-gas | 4423 |
| Thermal-nuclear | 2856 |
| Hydro | 6127 |
| Wind | 4200 |
| Solar | 2200 |

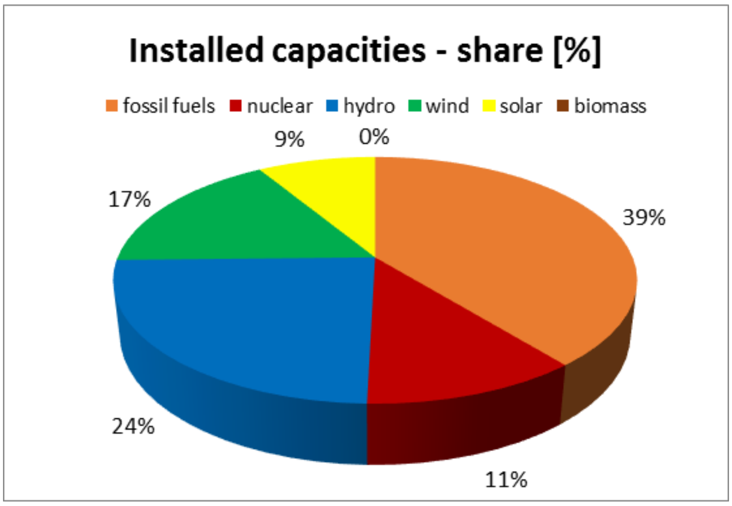



*Figure 43: Installed capacity per fuel type – Romania*

Considering the network constraints, several projects are expected to strengthen the Romanian interconnections. As already mentioned, NTC values at Romanian boarders with Bulgaria, Hungary and Serbia were revised according to the stated data source in Figure 44.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| | | | M1-2,9-12 | M3-8 | | | |
| RS - RO | 600 | 600 | 1300 | 1200 | TEL web - Transparency | 2020 - SOAF 2015 | Project 144: Pancevo-Resita (dbl) expected in 2015, Portile de Fier-Resita expected in 2017; Resita - Timisoara-Sacalaz-Arad expected in period 2023, NTC increase of 453MW (BTC W-E) and 737MW (BTC E-W) |
| RO - RS | 700 | 650 | 1400 | 1300 | | 2030 - TYNDP2016 | |
| RO - BG | 200 | 200 | 1500 | 1400 | TEL web - Transparency | 2020 - SOAF 2015 | |
| BG - RO | 300 | 350 | 1400 | 1400 | | 2030 - TYNDP2016 | |
| RO - HU | 700 | 700 | 1400 | 1300 | TEL web - Transparency | 2020 - SOAF 2015 | |
| HU - RO | 700 | 700 | 1300 | 1300 | | 2030 - TYNDP2016 | |

*Figure 44: Network constraints – Romania*

## 3.11 Serbia

Forecasted consumption in Serbia is at a level of 44.29 TWh in 2030. Observed peak load is 7,544 MW, with load factor of 67%. The highest monthly consumption is observed in December and January, while the lowest consumption is present from May to September.

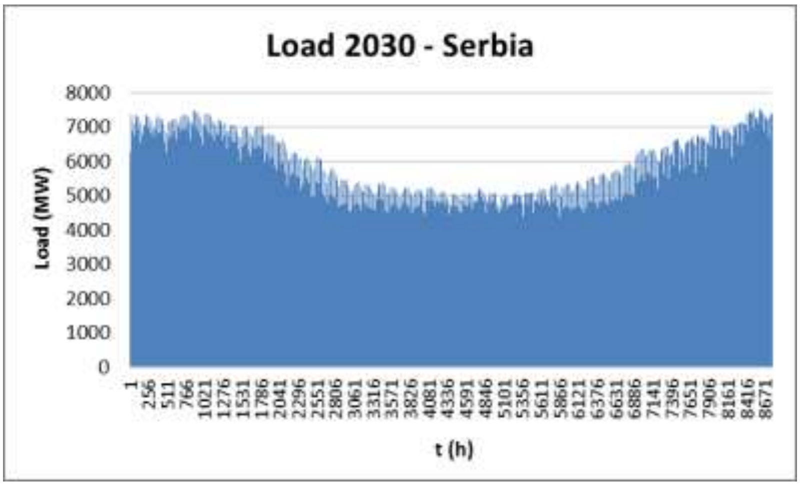



*Figure 45: Load profile 2030 – Serbia*

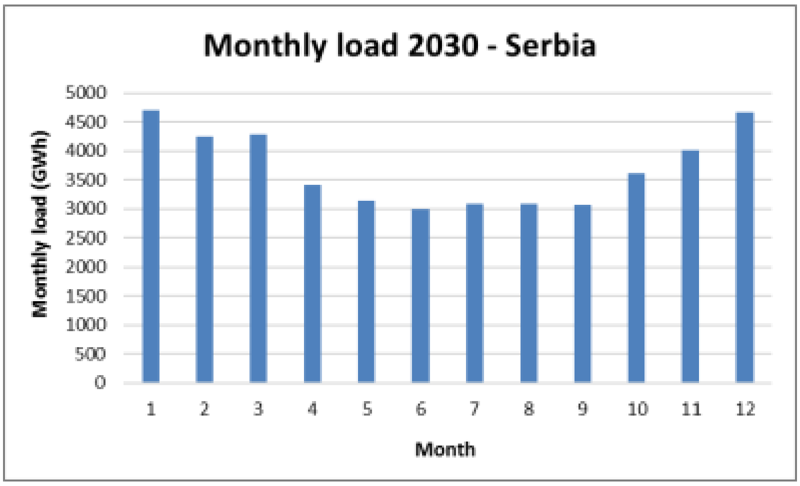



*Figure 46: Monthly load 2030 – Serbia*

In 2030 Serbia production portfolio will still be largely based on hydro-thermal mix. Thermal power plants will account about half of the total installed capacities, dominantly lignite fired power plants. Renewable generation will account around 10% of the total installed capacities, with commissioning of 834 MW of new wind generation and 20 MW of new solar generation.

*Table 12: Installed capacities per technology (2030) – Serbia*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 3838 |
| Thermal-gas | 609 |
| Hydro | 3302 |
| Wind | 834 |
| Solar | 20 |

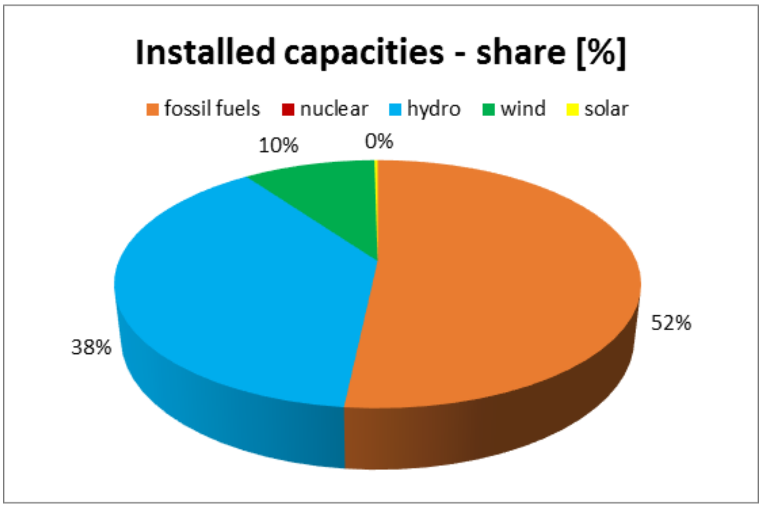



*Figure 47: Installed capacity per fuel type – Serbia*

In terms of network constraints, three major network reinforcements will have a high impact on Serbia. First of them, is the commissioning of Pancevo-Resita link between Serbia and Romania, which will increase the possibilities from energy transit from east to west (NTC value for this link revised according to the stated data source in the following figure). The second major project, represent the new interconnection to Macedonia which will strengthen the north-south corridor in SEE region. The third major project, represent the new interconnection between Bosnia and

Herzegovina, Montenegro and Serbia which will increase the NTC values at observed borders and facilitate the energy transit corridor towards Italy.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| | | | M1-2,9-12 | M3-8 | | | |
| RS - RO | 600 | 600 | 1300 | 1200 | TEL web - Transparency | 2020 - SOAF 2015<br>2030 - TYNDP2016 | Project 144: Pancevo-Resita (dbl) expected in 2015, Portile de Fier-Resita expected in 2017; Resita - Timisoara-Sacalaz-Arad expected in |
| RO - RS | 700 | 650 | 1400 | 1300 | | | |
| BG - RS | 300 | 350 | 800 | 850 | EMS, ESO, ENTSO-E Transparency | EKC based on TYNDP 2014 and RgIP CSE 2014 | NTC increase of 500 MW |
| RS - BG | 200 | 250 | 700 | 750 | | | |
| RS- MK | 0 | 500 | 700 | 500 | EMS, ENTSO-E Transparency | EKC, TYNDP 2014, RgIP CSE 2014 | Project 147: Leskovac/Vranje(RS) - Stip (MK) expected in 2015/2016, GTC increase of 800 MW |
| MK - RS | 0 | 300 | 300 | 300 | | | |
| RS - HR | 600 | 400 | 600 | 400 | EMS, ENTSO-E Transparency | | |
| HR - RS | 500 | 500 | 600 | 500 | | | |
| RS - HU | 800 | 800 | 800 | 800 | EMS, ENTSO-E Transparency | | |
| HU - RS | 700 | 700 | 700 | 700 | | | |
| RS - KS | 700 | 0 | 700 | 700 | Estimated. 'ENTSO-E Transparency from July 2015 | | After KOSTT will sign interconnection agreement with ENTSO/E expected in 2015 |
| KS - RS | 700 | 0 | 700 | 700 | | | |
| RS - ME | 700 | 600 | 1050 | 1500 | CGES, EMS, ENTSO-E Transparency | EKC, EMS, CGES, NOS BIH, TYNDP 2014, RgIP CSE 2014 | Regional study EKC:<br>2018: Conf2: Visegrad-B.Basta, B.Basta-Pljevlja, Brezna-B.Bijela<br>2023: Conf4: Visegrad-B.Basta, B.Basta-(Bistrica)-Pljevlja, Brezna-B.Bijela, Visegrad-(Pljevlja)-Bistrica |
| ME -RS | 650 | 700 | 1200 | 1450 | | | |
| RS - BA | 600 | 500 | 1200 | 1850 | EMS, ENTSO-E Transparency | | |
| BA - RS | 500 | 500 | 1000 | 1700 | | | |

*Figure 48: Network constraints – Serbia*

## 3.12 Slovenia

Similarly to Hungary, Slovenia is a boundary country of the area that is the primary focus of the analyses in this document. For several reasons Slovenian power plants play an important role and could not be left out of the simulations so the Slovenian power system is included, with a certain degree of aggregation. The Slovenian hydro power plants are grouped by the three river systems (Drava, Sava and Soča rivers) and considered as RoR (Run of River) HPPs.

In Slovenian power system the peak hourly load in 2030 is expected to be slightly above 2,300 MW, with minimum load slightly below 1,000 MW. Total annual consumption is expected to be 14.90 TWh. Regarding the monthly pattern, Slovenian monthly loads are relatively stable throughout the year, ranging from 1,100 GWh in April to 1,321 GWh in July.

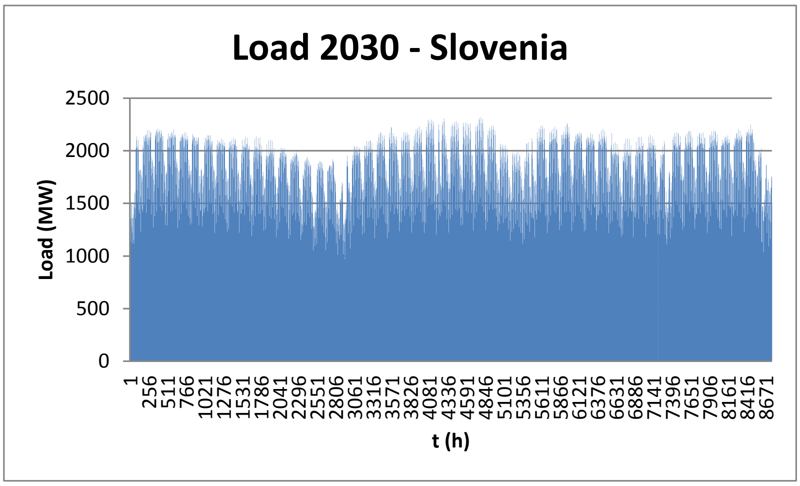



*Figure 49: Load profile 2030 – Slovenia*

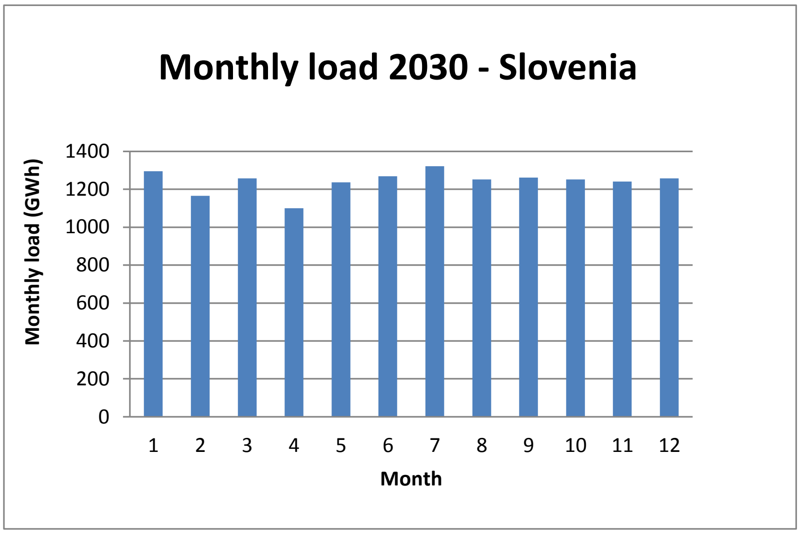



*Figure 50: Monthly load 2030 – Slovenia*

Regarding technologies, the largest share in installed power in Slovenia is expected to be in thermal power plants: 600 MW in lignite TPPs and 715 MW in gas-fired TPPs, totaling in 38% share of TPPs. Slightly less than a third (31%) of Slovenian installed power will be in HPPs, which are modelled as three large RoR HPPs in the simulations. In 2030, 20% of Slovenian installed power will be in NPP Krško, jointly owned by Croatian HEP and Slovenian Gen-Energija. In Slovenia, wind is expected to have a less important role than solar: there will be 275 MW in solar power and 106 MW in wind power (8% and 3% share of installed power, respectively).

*Table 13: Installed capacities per technology (2030) – Slovenia*

| Technology | Installed Capacity (MW) |
|---|---|
| Thermal-lignite | 600 |
| Thermal-gas | 715 |
| Thermal-nuclear | 696 |
| Hydro | 1044 |
| Wind | 106 |
| Solar | 275 |

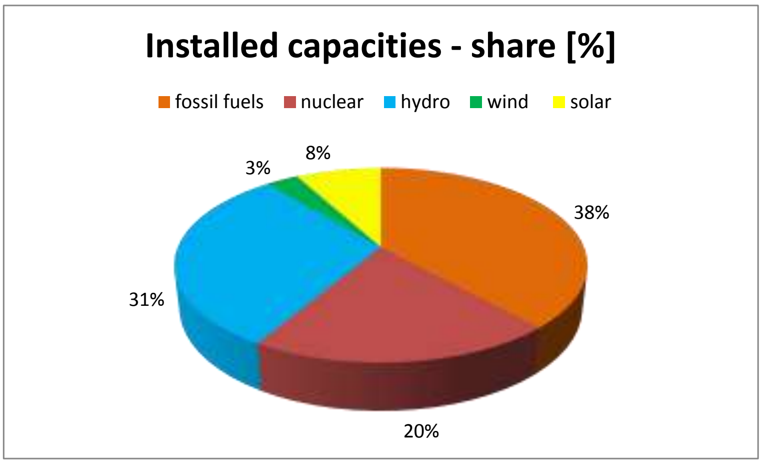



*Figure 51: Installed capacity per fuel type – Slovenia*

Regarding network constraints, by 2030 there are no significant changes (new capacities) expected on Slovenia-Croatia interconnection. Except for the transmission line Croatia - Slovenia presented in the following figure, market model also includes one link to Italy with 1,000 MW of maximum allowed flow in both directions.

| NTC YEAR | 2015 | 2014 | 2030 | 2030 | Data source for current state 2015/14 | Data source for 2020-2030 | Comments |
|---|---|---|---|---|---|---|---|
| Season | Win | Sum | Win/Aut | Sum/Spr | | | |
| HR - SI | 1500 | 1000 | 1500 | 1000 | CAO, ENTSO-E Transparency | EIHP, EKC | |
| SI - HR | 1500 | 1100 | 1500 | 1100 | | | |

*Figure 52: Network constraints winter regime – Slovenia*

# 4 INPUT DATA OVERVIEW AND MODELLING ASSUMPTIONS

An overview of input data with relevant modelling assumptions is provided in this chapter.

## 4.1 Generation

Installed capacities in 2030 per country summarized by technology type are presented in the following table. Type TPP includes thermal power plants on gas, hard coal, lignite and biomass, while installed capacities in nuclear power plants are presented separately.

Total installed capacity in SEE region amounts to 109 GW, most of which is installed in thermal power plants (41%). Hydro power plants also have a relatively large share (26%), while the smallest share is in solar capacities (8%), as illustrated in Figure 53.

*Table 14: Installed capacities per technology type in 2030*

| Installed capacity (GW) | Albania | Bosnia and Herz-egovina | Bulgaria | Greece | Croatia | Hungary | Kosovo | Monte-negro | Mace-donia | Romania | Serbia | Slovenia | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HPP** | 3.15 | 2.27 | 2.61 | 4.53 | 3.19 | 0.00 | 0.04 | 1.11 | 1.26 | 6.13 | 3.30 | 1.04 | **28.62** |
| **TPP** | 0.50 | 2.47 | 5.26 | 10.11 | 2.74 | 5.12 | 1.66 | 0.20 | 1.51 | 9.88 | 4.45 | 1.32 | **45.21** |
| **Nuclear** | 0.00 | 0.00 | 2.08 | 0.00 | 0.00 | 4.40 | 0.00 | 0.00 | 0.00 | 2.86 | 0.00 | 0.70 | **10.03** |
| **Solar** | 0.10 | 0.10 | 1.80 | 4.00 | 0.20 | 0.08 | 0.03 | 0.02 | 0.04 | 2.20 | 0.02 | 0.28 | **8.86** |
| **Wind** | 0.20 | 0.64 | 1.60 | 6.20 | 1.30 | 0.80 | 0.13 | 0.19 | 0.15 | 4.20 | 0.83 | 0.11 | **16.35** |
| **TOTAL** | **3.95** | **5.48** | **13.35** | **24.84** | **7.43** | **10.39** | **1.85** | **1.52** | **2.95** | **25.26** | **8.60** | **3.44** | **109.07** |

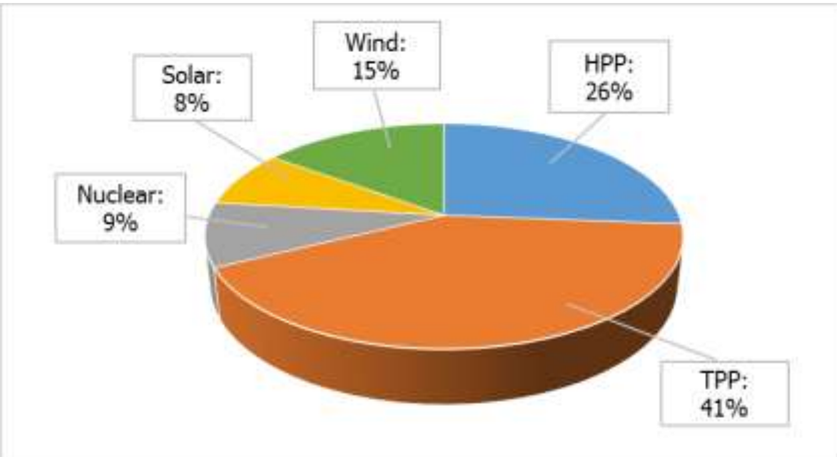



*Figure 53: Share of total installed capacities in SEE per technology in 2030*

## 4.2 Demand

As already mentioned, demand for all countries is modelled according to ENTSO-E market modelling database. Vision 1 for 2030 from TYNDP 2014 was used for forecasted demand for all modelled countries, except for Greece. Greek demand according to the TYNDP 2014 seemed too high and resulted in some strange results in the first market simulation runs. Thus, Greek demand was reviewed and adjusted according to the TYNDP 2016 Vision 1 for 2030.

Total annual consumption in 2030 for modelled countries in SEE region amounts to 346.31 TWh and is presented by countries in Figure 54. After revision of Greek demand, the highest demand among countries is in Romania (66.40 TWh), while the lowest is in Montenegro (5.39 TWh).

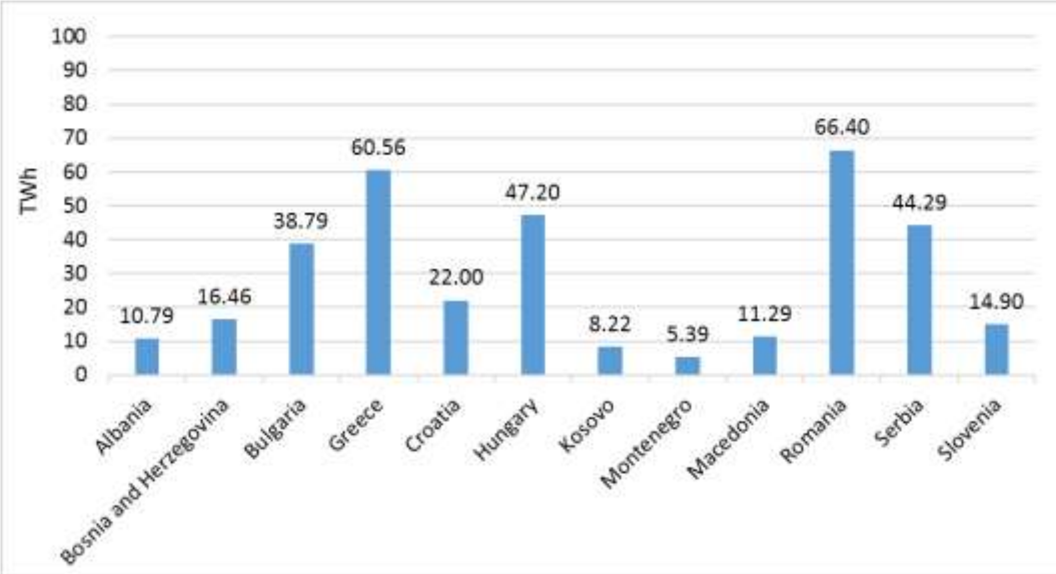



*Figure 54: Annual consumption in SEE in 2030*

Average consumption growth rate in SEE region for the period 2014-2030 is 1.47%. The lowest growth rate is predicted for Slovenia and Hungary, while the highest is expected in Kosovo. Annual consumption in Kosovo is expected to reach 8.22 TWh in 2030, from the 5.47 TWh level in 2014.

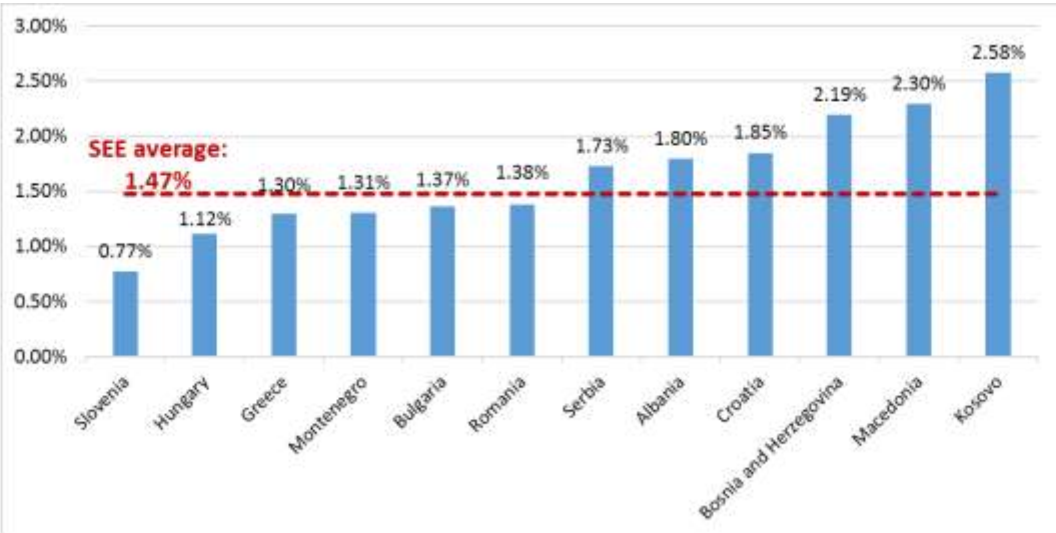



*Figure 55: Consumption growth rate in SEE for the period 2014-2030*

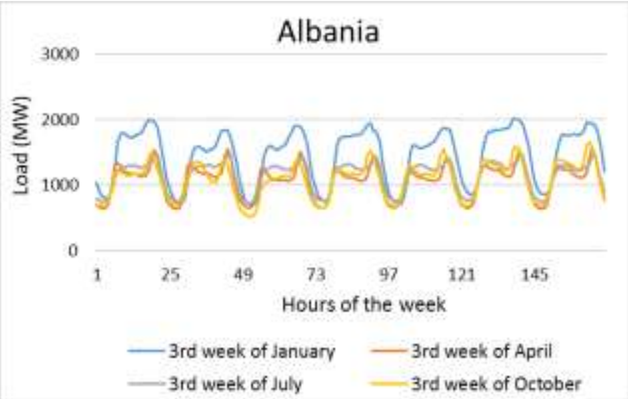
Consumption increase in absolute change (GWh) as well as in percentages (%) can be found in Table 15, sorted according to growth rate from smallest to largest. Although the highest consumption growth rate is expected in Kosovo, Romanian consumption has the lead in terms of increase in GWh.

Table 15: Consumption increase in SEE in the period 2014-2030

| Increase 2014-2030 | SI | HU | GR | ME | BG | RO | RS | AL | HR | BA | MK | KS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GWh** | 1723 | 7682 | 11301 | 1012 | 7573 | 13111 | 10618 | 2673 | 5592 | 4825 | 3440 | 2749 |
| **%** | 13 | 19 | 23 | 23 | 24 | 25 | 32 | 33 | 34 | 41 | 44 | 50 |

The complete hourly demand time series is used in the market simulations, so two examples of hourly demand (Albania and Romania) are illustrated by the following figure.

Among the four weeks presented, in both countries the highest demand occurs in the 3rd week of January although Albanian power system is significantly smaller than Romanian. The most notable characteristic of Albanian load profile is that the demand rises considerably in winter months (blue line illustrates 3rd week of January). Other three weeks presenting Albanian demand are practically equal, what is not the case in Romanian demand.



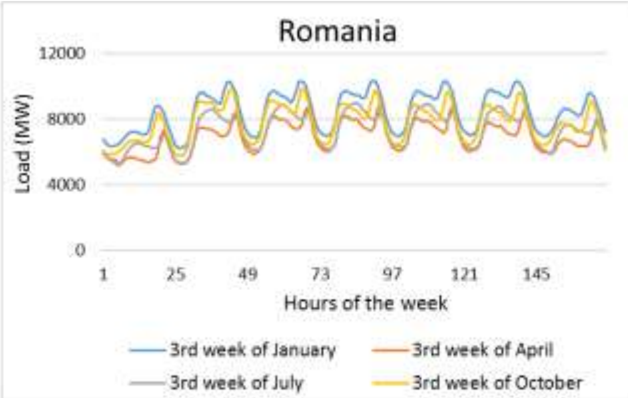




Figure 56: Hourly demand example for Albania and Romania

## 4.3 Fuel and $CO_2$ emissions prices

Fuel prices from ENTSO-E Market Modelling Database for TYNDP 2016 (2030 Vision 1) are used as the referent fuel prices where fuel cost data was missing. In the first market simulation runs fuel prices from the TYNDP 2014 (2030 Vision 1) were used as the referent prices, but after publication of TYNDP 2016 fuel prices were revised according to the new TYNDP.

Comparison of fuel prices according to the Vision 1 for 2030 is presented in the following table. As can be seen, TYNDP 2016 offers more reasonable price projections, especially in terms of lignite price which was notably low in TYNDP 2014.

Table 16: Fuel prices

| Fuel | Prices (TYNDP 2014) (€/GJ) | Prices (TYNDP 2016) (€/GJ) |
|---|---|---|
| **Nuclear** | 0.377 | **0.46** |
| **Lignite** | 0.44 | **1.10** |
| **Hard coal** | 3.48 | **3.01** |
| **Gas** | 10.28 | **9.49** |

$CO_2$ emissions prices are also considered in market analyses and included in the optimization objective function. Assumption on $CO_2$ emissions prices is taken from TYNDP 2016 (2030 Vision 1) in the amount of 17 €/ton. Compared to the TYNDP 2014 where $CO_2$ price in 2030 Vision 1 was 31 €/ton, $CO_2$ emissions prices are considerably lower in TYNDP 2016. Additional set of scenarios (Reference, Base, Alternative) without Carbon Cost was performed for evaluating the effect of $CO_2$ emissions prices.

## 4.4 Italy, Turkey and Central Europe modelling assumptions

Italy, Turkey and Central Europe are modelled as external nodes with a predefined input time series of electricity prices. The prices are insensitive to fluctuations of prices in SEE region and NTC values are used to constrain cross-border energy exchange with SEE region. Generation capacities and load demand are not modelled for these nodes. Price time series is constructed from the actual prices observed on the power markets, as described below.

### 4.4.1 Italy

For the Italian power market, a time series of observed market prices in 2015 at the Italian Power Exchange (IPEX) is used. The prices are available on the Italian market operator website[3], and the average price in 2015 was 52.31 €/MWh[4]. Hourly prices variation in 2015 are presented in the following figure, and it can be observed that prices varied in the range 5.62-144.57 €/MWh.

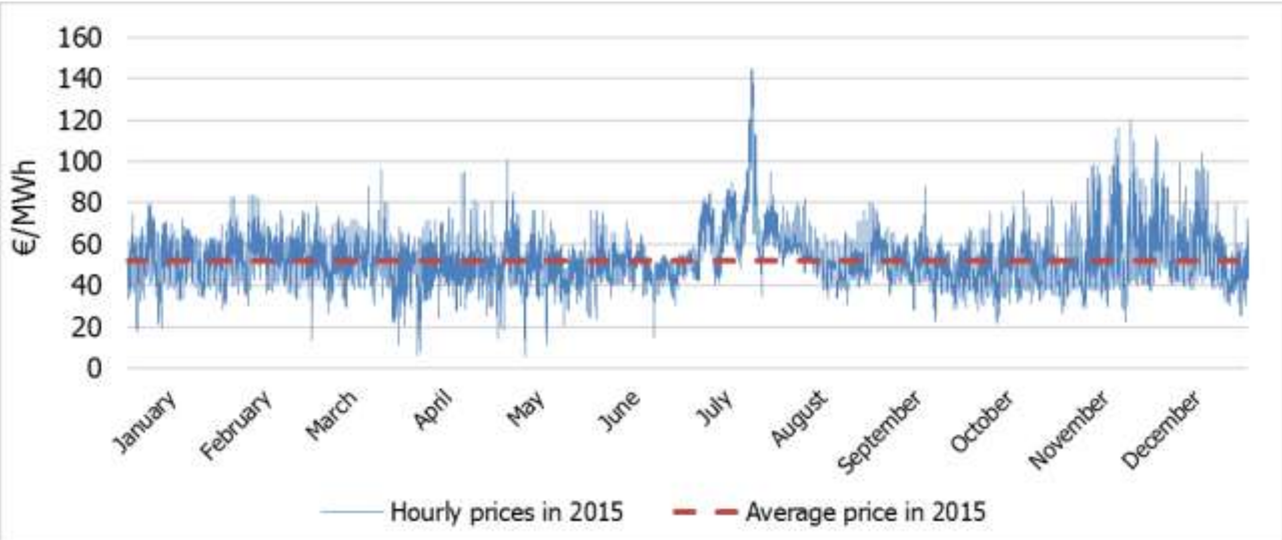



*Figure 57: Hourly prices in 2015 on the Italian power market*

Example of daily prices variation is depicted for the 3rd Wednesday in October in Figure 58, while average monthly prices are given in Table 17.

[3] GME, Gestore Mercati Energetici, web site: http://www.mercatoelettrico.org/
[4] Single National Price (Prezzo Unico Nazionale - PUN), average of the zonal prices weighted on the zones' volumes

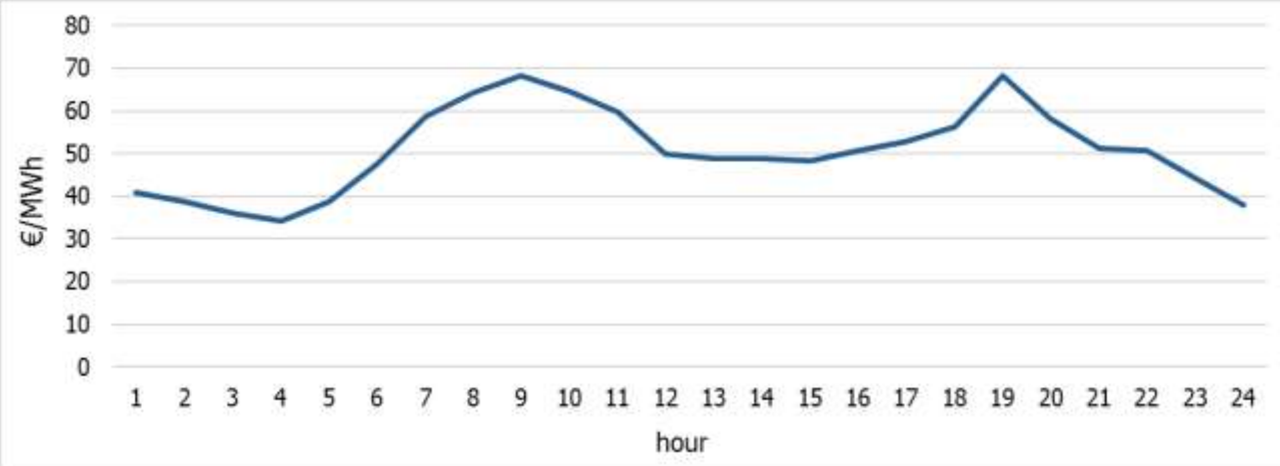



*Figure 58: Hourly prices during 3rd Wednesday in October on the Italian power market*

*Table 17: Average monthly baseload prices in 2015 on the Italian power market*

| Month | PUN 2015 (€/MWh) |
|---|---|
| January | 51.10 |
| February | 54.50 |
| March | 49.97 |
| April | 47.88 |
| May | 47.25 |
| June | 48.64 |
| July | 67.79 |
| August | 52.71 |
| September | 49.37 |
| October | 47.67 |
| November | 55.08 |
| December | 55.66 |

## 4.4.2 Turkey

Modelled electricity prices for Turkey are based on observed market prices from October 2015 to September 2016 on EXIST (Energy Exchange Istanbul). The prices are available on the Turkish Energy Markets Operation Company – EPIAS website[5] and the average price for the observed period was 134.54 TL/MWh i.e. 41.67 €/MWh[6].

Power exchange in Turkey is still in the process of development so electricity is mostly traded through bilateral contracts. Based on the data on EPIAS, electricity market model for Turkey was developed which takes into account intra-daily price movement, as well as weekly (workday/weekend) and monthly price movement. Price in one hour is defined as a product of respective hourly coefficient, monthly coefficient and average price. Hourly coefficients which present intra-daily price movement pattern are depicted in Figure 59, while Figure 60 shows monthly coefficients which differ for working days and weekends.

[5] EPIAS, Enerji Piyasaları İşletme A.Ş., web site: https://www.epias.com.tr/
[6] Converted into euros with different monthly exchange rates for respective months (range 3.08-3.22 TL/€).

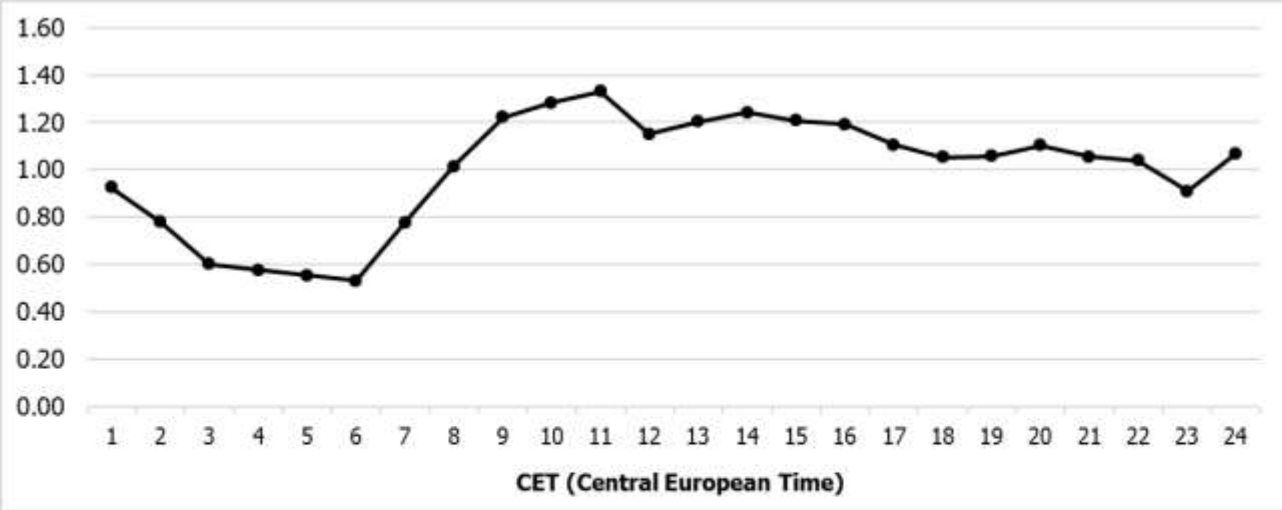



*Figure 59: Hourly coefficients for power market in Turkey*

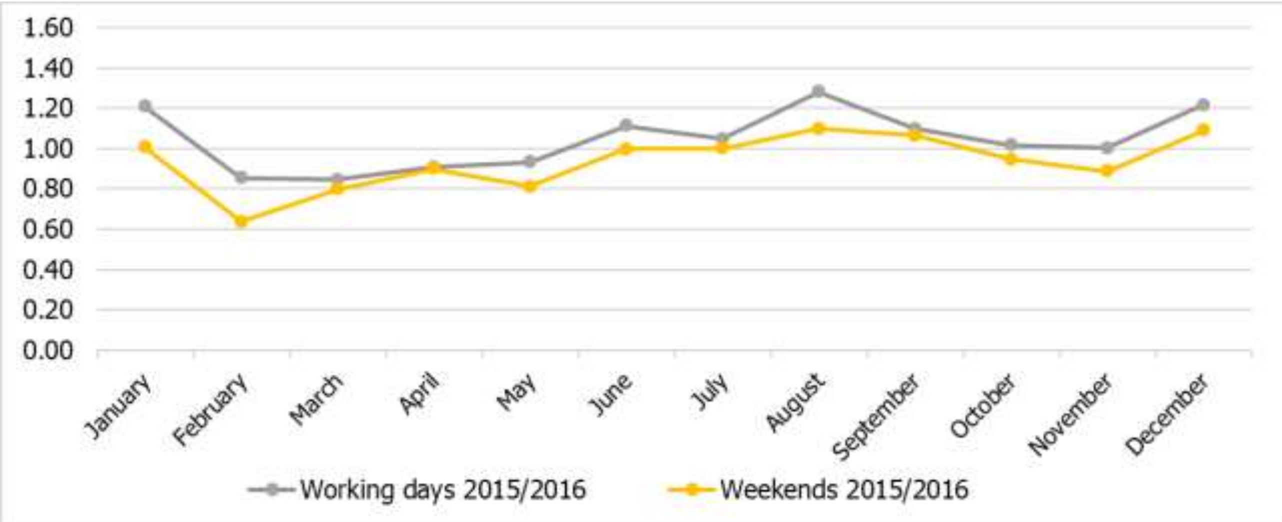



*Figure 60: Monthly coefficients for power market in Turkey*

### 4.4.3 Central Europe

Central Europe region is modelled as a spot market equivalent for Central Europe with two links (2x1,000 MW) constraining exchange with SEE region, one with Slovenia and other with Hungary.

Electricity prices for Central Europe are based on observed market prices from October 2015 to September 2016 on EEX (European Energy Exchange), i.e. EPEX SPOT prices for Germany/Austria. The prices are available on the EPEX SPOT website[7] and the average price for the observed period was 27.88 €/MWh. In observed historical market prices on EPEX SPOT periods of negative electricity prices can be observed (Figure 61), thus for market in Central Europe was created market model as in Turkey, by defining price in one hour as a product of respective hourly coefficient, monthly coefficient and average price.

[7] EPEX SPOT, European Power Exchange web site: http://www.epexspot.com/

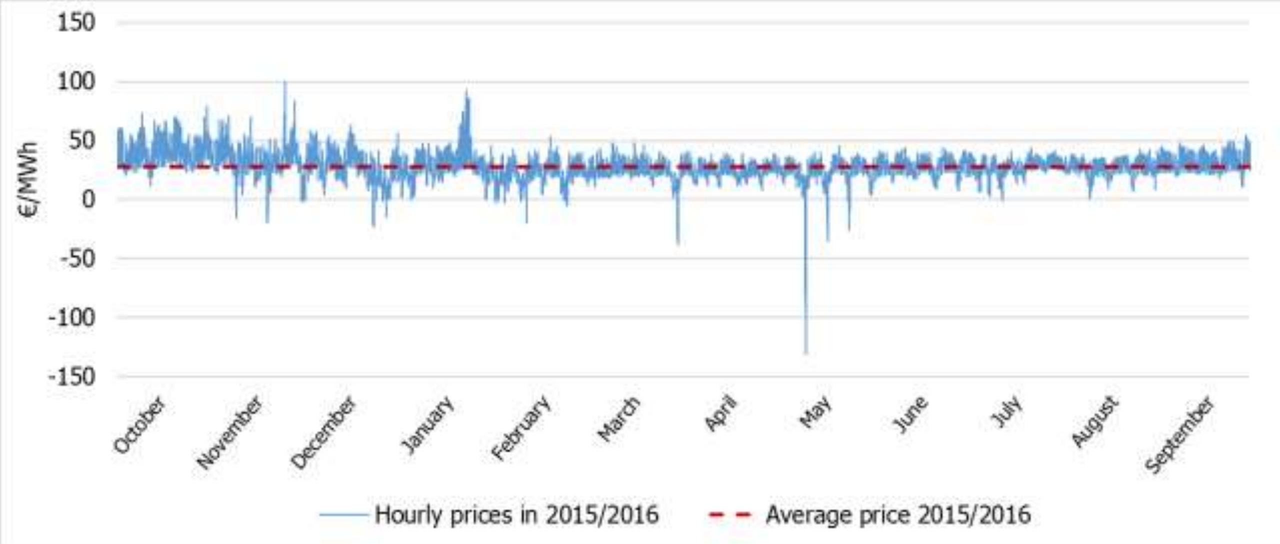



*Figure 61: Hourly prices form October 2015 to September 2016 on EPEX SPOT*

Hourly coefficients which present intra-daily price movement pattern and monthly coefficients which differ for working days and weekends are presented in the following figures.

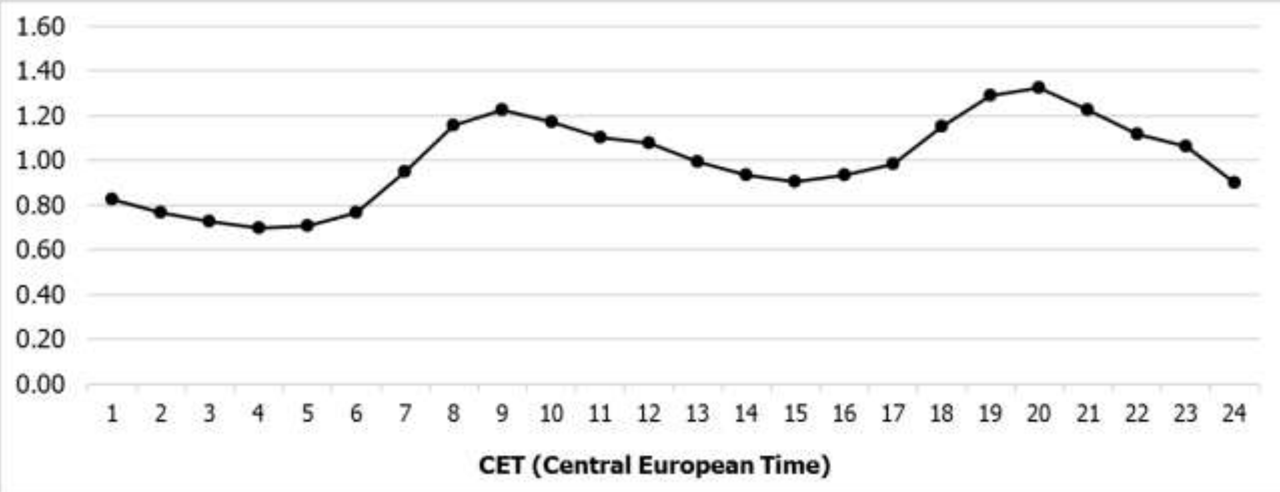



*Figure 62: Hourly coefficients for power market in Central Europe*

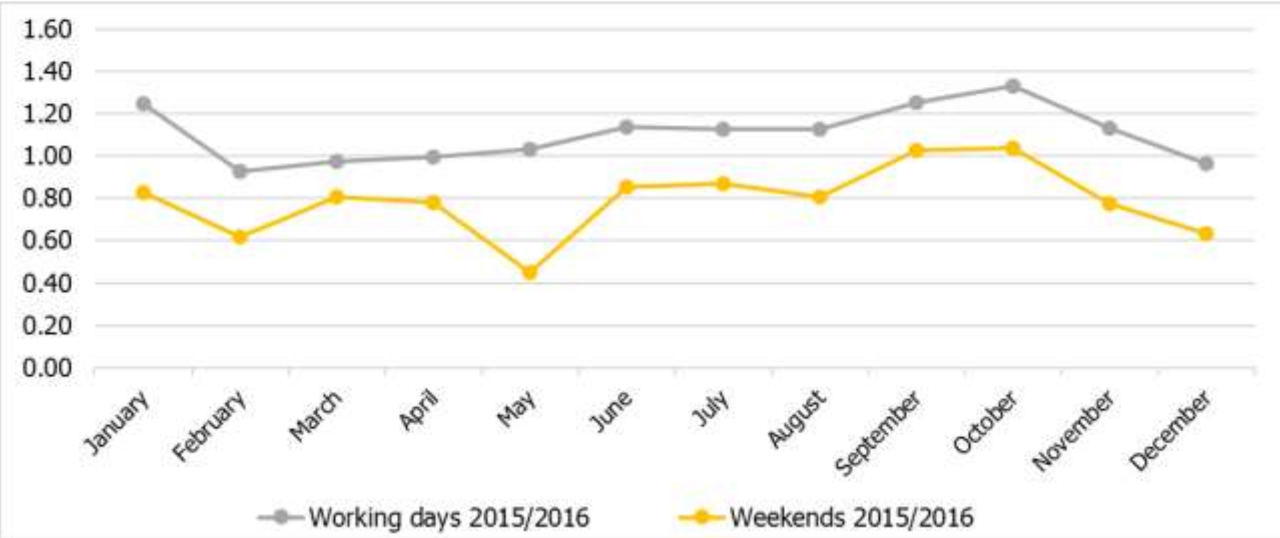



*Figure 63: Monthly coefficients for power market in Central Europe*

### 4.4.4 Market price assumptions for 2030

While prices in the SEE region are determined by marginal costs of dispatched generating units, and thus the result of the optimization, prices in Italy, Turkey and Central Europe are exogenous variable for the market analyses. Hourly prices variation throughout the year are modelled according to historical data, but in order to assume market prices level in 2030 an assumption was made that the price spread between SEE region, Italy, Turkey and Central Europe will remain the same as in 2015/2016. Since no publicly available data on SEE market prices are available for 2015, the average price for the region is taken from Hungarian HUPX market[8].

In the first step, market simulation without Italy, Turkey and Central Europe (Isolated SEE scenario) was run to determine what would be the average annual market price in the SEE region if the region was isolated i.e. no power flow outside the SEE region. Then, in the second step market prices for Italy, Turkey and Central Europe in 2030 are determined based on the relation of average historical prices in 2015/2016. In this way, average market prices in 2030 are determined as a product of the actual market price in 2015/2016 and respective price scalar. Price scalars are calculated as a ratio of assumed average market prices in 2030 and average modelled market prices for 2015/2016 as presented in sections 4.4.1, 4.4.2 and 4.4.3. Calculated price scalars for 2030 can be found in the following table.

*Table 18: Market price assumptions for 2030*

| Wholesale electricity price (€/MWh) | 2015 | 2030 | Modelled market price for 2015/2016 | Price Scalar for 2030 |
|---|---|---|---|---|
| **SEE** | 40.60 | 54.41* | | |
| **Italy (GME)** | 52.31 | 66.11 | 52.31 | 1.2639 |
| **Turkey (EPIAS)** | 45.62 | 59.42 | 41.67 | 1.4260 |
| **Central Europe (EEX)** | 31.63 | 45.43 | 27.88 | 1.6297 |

**Average annual load-weighted price in SEE region as a result of the Isolated SEE Scenario.*

[8] Hungarian Power Exchange, www.hupx.hu

# 5 MARKET MODEL OVERVIEW

## 5.1 Methodological approach and overview of main market indicators

Since the liberalization of the electricity sector, the transmission expansion planning process has become a complex task in which network planners need to handle several uncertainties and consider different risk situations. Some important criticalities make this task at the same time crucial and very delicate. For this reason, transmission planners need to fully capture all the impacts a project may have, and to examine a wide range of possible system conditions.

In South-East Europe (SEE) there are uncertainties for the East-West and North-South transmission adequacy linked with the possible new undersea HVDC connections between SEE and Italy, the connection of Ukraine to the rest of the Europe and a huge potential of RES in the overall region that could, with new transits from Ukraine, Turkey, Romania and Bulgaria, make congestions on the above mentioned directions.

Investigation in this Study will examine these uncertainties by going one step further and applying market analyses with consideration of the wider outlook of the market integration. Challenges in the market evolution process that deserves further detailed analyzes are:

- mutual influence of SEE and Italian electricity markets with focus on new HVDC connections between SEE and Italy,
- integration of renewable energy sources in SEE,
- perspective transmission corridors to support the electricity trading patterns across SEE.

Impact of regional connections towards Italy are assessed by analyzing three scenarios:

- Reference Case scenario: with existing HVDC Greece-Italy,
- Base Case scenario: with existing HVDC Greece-Italy and HVDC Montenegro-Italy (under construction) and
- Alternative Case scenario: with existing HVDC Greece-Italy, HVDC Montenegro-Italy (under construction), HVDC Croatia-Italy and HVDC Albania-Italy.

Target year for the analyses is 2030 and market simulations are performed using the SEE regional model implemented in *PLEXOS: Integrated Energy Model* modelling software (PLEXOS in further text). PLEXOS is state of the art software tool for electricity market simulation.

The following approach is applied within this Study:

**Step 1**

Assessment of the relevant load, generation and network constraints is defined on the basis of the collected TSOs questionnaires harmonized with other relevant sources (ENTSO-E pan-European market modelling database, GIS study, TYNDP and other).

The outcome of this process presents the data consolidated within the created SECI Market modelling database for South East Europe:

1. The forecasted load values for 2030
2. The list of the generating units with their technical characteristics and operational constraints
3. Short run marginal production cost of the units
4. Definition of the inter-area connection capacities for the scenarios on the basis of Net Transfer Capacities (NTC)

These values are used as input parameters for market modelling and simulations.

**Step 2**

Market simulations are carried out with the aim of obtaining optimal system dispatching subject to constraints between market areas. This step provides as the main output the optimal generation dispatch and marginal clearing prices (MCPs) as well as identification of a possible congestions of transmission capacity between the market areas.

In this Study, market simulations are carried out using PLEXOS as a software tool. Chronological simulations are carried out for 8760 hours in 2030, i.e. whole year. The "chronological" aspect refers to the preservation of the chronological sequence of events in the simulation and also by considering, in the optimization process, those constraints given by previous states. By applying inter-temporal constraints, results give more realistic amount of available energy (and capacity). In the market calculations, the analyzed power systems have been suitably represented by major demand centers, all generation plants and cross-border transmission lines.

Power system operation is simulated with an 1-hour time step and by the means of a total system cost minimization (including fuel costs and $CO_2$ emissions penalties) in user-definable sequential time steps, while taking into account the many technical constraints of the generating units and system such as minimum up and down times of power plants, ramp rates of power plants, fuel prices, available generation per week, etc.

Establishing equilibrium between the generation and demand of electricity depends on many parameters such as availability of primary energy sources, prices of fuel, bidding strategies etc. The implicit assumption applied within the market simulation in this Study is that the market operates in perfect competition, which is not the case in reality but it is the fairest guess. In that case, the system marginal price is set by the operating cost of the most expensive unit on-line during a given time period. With an almost inelastic consumer bid curve, which is typical in electricity markets, the total dispatch cost minimization provides maximization of social welfare.

**Results**

Market simulation gives the following results for analyzed scenarios:

- overview of countries electricity balance in SEE region (production, consumption and exchanges),
- average generation cost for each country,
- wholesale electricity prices for each country,
- cross-border power exchanges for each border in the region,
- HVDC link loadings for each HVDC submarine cable and
- location (border) and frequency/duration of market congestions in SEE region.

Among all simulated hours, selected cases (hours) from market model will be investigated by network analyses:

- highest consumption in SEE region,
- highest RES penetration in SEE region and
- highest cross-border exchanges in SEE region.

For this snapshot hours, market simulation produces load profile, generation dispatch and/or area interchange, as a basis for creating relevant network models for further network analyses.

## 5.2 Creation of SEE regional market model in PLEXOS

The market study investigates expected generation pattern and power exchanges in SEE region, taking into account inter-regional SEE electricity market synergies and the prospective integration with Italian market, as well as relatively high level of RES integration in SEE region. The existing main power trade corridors in the SEE region (North-South and East-West) are expected to be highly congested in the future, becoming even more so with market integration.

Namely, considerable power exchanges in East-West direction are related to the fact that Bulgaria and Romania are the main exporters in SEE. Furthermore, there are significant power exchanges in the North-South/Southeast direction are related to the fact that the GR, MK, ME, HR and AL are mainly importing, plus the influence of Italy importing over (future) HVDC cables.

Starting with the database of collected data, the following approach is adopted with regard to countries being modelled:

- Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Kosovo, Macedonia, Montenegro, Romania and Serbia are modelled on plant-by-plant level of details,
- Greece, Hungary and Slovenia are aggregated per technology clusters (thermal by fuel type, hydro by type, RES),
- Italy, Turkey and Central Europe are modelled as external spot markets where the market clearing price series is insensitive to fluctuations of prices in SEE, constrained with transmission capacity.

The target year for the analyses is 2030. The market model includes entire 2030 on an hourly basis, but for a more detailed illustration of the results four typical weeks in a year, representative for the four seasons and with average hydrology (3$^{rd}$ week of January, 3$^{rd}$ week of April, 3$^{rd}$ week of July and 3$^{rd}$ week of October) will be presented. The renewable energy sources penetration is assuming relatively high RES penetration, and the load (consumption) is modelled according to the most realistic consumption forecast (Vision 1 for 2030 from TYNDP).

The PLEXOS software is an integrated energy model designed as market simulation model. It was first developed as an electricity market simulator. Its functionality was then extended so that the recent versions of PLEXOS integrate gas and electric energy market model. The PLEXOS simulation platform is robust and extensible. PLEXOS is a high-performance simulation platform, already operationally used by energy market participants, system planners, investors, regulators, consultants and analysts worldwide. Several TSOs and other relevant entities use PLEXOS on a daily basis, and EIHP experts have more than 10 years of experience in the use of PLEXOS for the studies in Croatia, the region and the world.

The PLEXOS simulations are based on mathematical programming. The system supports various planning horizons from long-term to short-term, and several different time steps: the simulated time frames can range from minutes and hours to tens of years. The PLEXOS models can capture specifics of short-term operational limits, as well as the effects of system expansion. Further information and details on PLEXOS can be found on Energy Exemplar web site[9].

The PLEXOS system is based on an object-oriented model of all the simulated elements. PLEXOS provides a graphical user interface, slated towards model design and development and the collection of the input data.

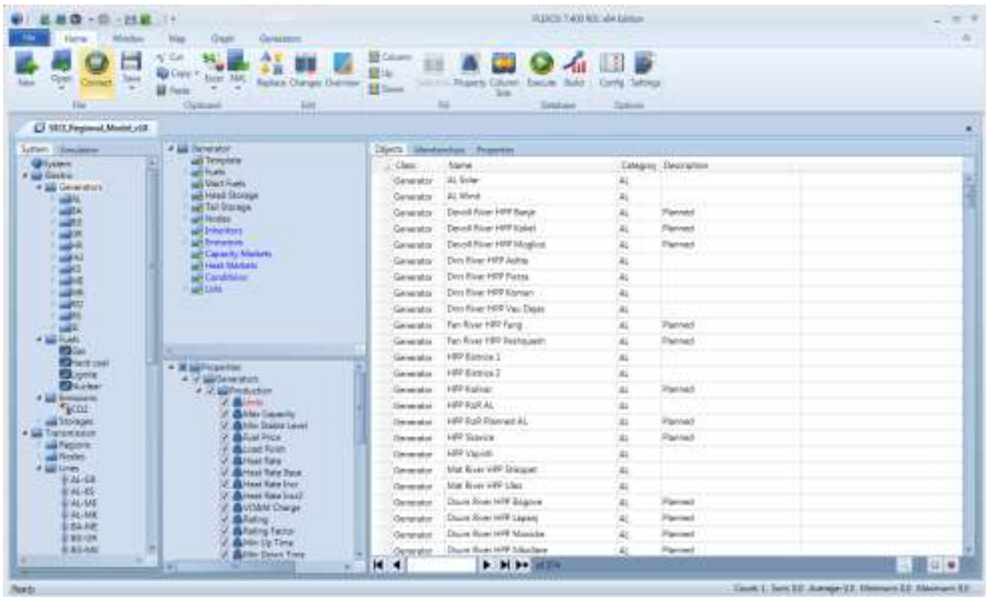


*Figure 64: PLEXOS software – Modelling user interface*

Once the model is established, the PLEXOS system formulates the mathematical programming model (a set of equations describing the system behavior) and uses a state of the art mathematical solver[10] to solve the formulated problems. Based on the input data, the PLEXOS uses mathematical programming to solve the system of equations resulting with optimal unit commitment and dispatch, respecting all the imposed constraints. Once the optimization process is finished, the PLEXOS user interface can be used to analyze, plot and export the simulation results.

With regard to modelling detail, PLEXOS supports several detail scales of the technical and operational characteristics of the power system elements (e.g. generator operational limits, interconnection line power flow limits etc.).

Considering the size of the simulated system and the amount of collected data, the general modelling assumptions and methodology are defined hereinafter.

Each of the modelled countries is modelled as a single node, i.e. no inter-country lines are modelled. All the generators within the country are connected to this aggregate node. The nodes are connected with fictitious lines whose maximum capacity is equal to the nominal transfer capacities between the two countries. PLEXOS model includes a simplified DC power flow model that is able to limit the total line flows and thus respect the interconnection capacity limits.

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[9] Energy Exemplar, PLEXOS: http://energyexemplar.com/software/plexos-desktop-edition/

[10] Xpress-MP solver is used in this study

All the relevant generator data are included in the model (e.g. minimum stable level, ramp limits etc.). This is especially important for the NPPs and large TPPs that have a limited range of flexibility. The fuel costs are modelled so that adjustments of fuel costs are correctly respected in all the generators using the fuel in question – this way different assumptions on the fuel prices can be easily simulated.

The simulation time step is hourly: the wind power, solar power and load are modelled with the hourly time series available in the input data. The total wind and solar power production will result from the resource limits embedded in the input time series. This is done my modelling one solar and one wind power plant in each country that represent aggregated generation from these renewable sources.

Storage hydro power plants operation is determined by its monthly inflow or monthly production data and additionally storage operational limits are included in the model. RoR (Run of River) HPPs generation is determined by fixed monthly generation data. For the hydro power plants where the production data is not known, the energy production limits are extrapolated from hydrology patterns, what is a realistic setup approach used in several studies by EIHP experts. A certain degree of aggregation is used for some HPPs – given that their operation is subject to restrictions of hydrology, several small RoR HPPs can be safely represented with a single HPP that sums (aggregates) their total production.

As stated above, the neighboring countries that are not the primary subject of these analyses are modelled in a different manner, with a reduced level of detail in the modelling. By using this model the influence of neighboring countries is included, while keeping the whole model complexity on a tractable scale. This means the Greek, Hungarian and Slovenian TPPs are aggregated per technology. Furthermore, in Slovenia, hydro power plants are also aggregated by the rivers system (Drava, Sava and Soča) and considered as RoR HPPs. NPP Krško in Slovenia and NPP Pakš in Hungary are modelled in detail, since their operation has a significant impact on the regional power system.

Italy, Turkey and Central Europe are modelled as three spot market nodes external to the SEE system, with possible exchanges to the modelled region constrained by the relevant NTC values. The price movement in these nodes are modelled using a simulated hourly price time series, i.e. the price movement time series in these nodes belongs to input data and the exchange is the result of simulations.

To conclude, market model includes 580 generating units in 12 countries in SEE region modelled with hourly demand. The mentioned number of generating units refers to 153 TPPs, 6 NPPs, 124 storage HPPs, 53 RoR HPPs, 12 wind and 12 solar power plants across SEE region. Additional 3 external markets representing Italy, Turkey and Central Europe are modelled using a simulated hourly price time series. Market model contains 28 cross-border lines and 4 submarine HVDC cables. Graphical presentation of the regional market model with links between countries can be seen in Figure 65.

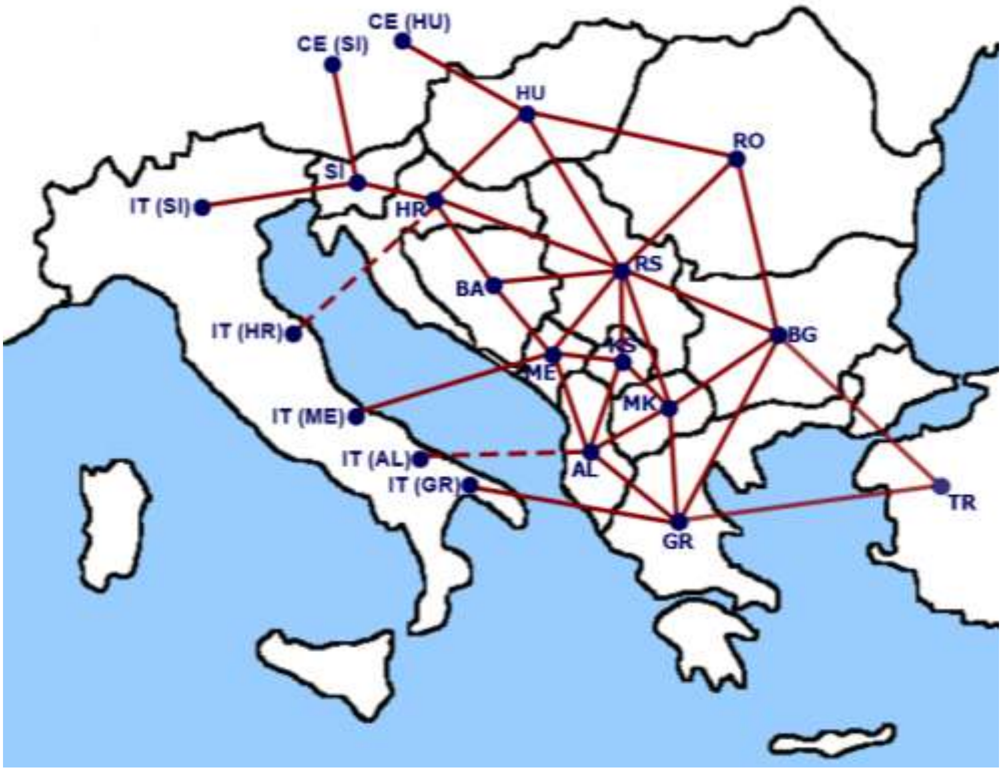


*Figure 65: Regional market model*

To avoid loop power flows closing from SEE region over Italy and Central Europe back to SEE region, Italy and Central Europe are not modelled as just one representative node like other countries, yet as several separated nodes.

# 6 MARKET ANALYSES RESULTS

This chapter presents market simulation results for Base and Alternative Case scenario and their comparison with Reference Case scenario which is only used for results comparison. Isolated SEE scenario is used to determine electricity market price assumptions for Italy, Turkey and Central Europe in 2030 and therefore presented results only contain electricity balance of SEE countries with average wholesale price. Additionally, this chapter presents results of set of scenarios without Carbon Cost which are used for evaluating the effect of $CO_2$ cost on market prices. Section 6.3 gives the most important results comparison for the respective scenarios.

Simulation timeframe is 2030 and time step is one hour, but results all mostly aggregated on a yearly basis. Weekly results for four typical weeks in a year (3rd week of January, April, July and October) are presented for generation, import and export, wholesale prices and HVDC cables flow, while hourly values are given only in a few examples (e.g. wholesale prices for three selected countries) due to huge amount of hourly data as a result of market simulations.

## 6.1 Isolated SEE scenario

Isolated SEE scenario includes 12 countries in SEE region, without any links to external markets (Italy, Turkey and Central Europe). Table 19 gives electricity balances results (load, generation and exchange) with resulting average wholesale market price. Total load includes customer load (demand) and pump load for pumped storage HPPs, so where pump load value equals zero it is evident that PSHPPs are not modelled. Net interchange is presented as the difference between export and import, hence positive net interchange value means the country is a net exporter.

*Table 19: Electricity balances of SEE countries (Isolated SEE)*

| Country | Load (GWh) | Generation (GWh) | Pump Load (GWh) | Customer Load (GWh) | Imports (GWh) | Exports (GWh) | Net Interchange (GWh) | Price (€/MWh) |
|---|---|---|---|---|---|---|---|---|
| **AL** | 10,791.50 | 10,817.14 | 0.00 | 10,791.50 | 4,367.88 | 4,393.52 | 25.64 | 54.28 |
| **BA** | 16,469.84 | 14,221.52 | 9.53 | 16,460.31 | 9,487.39 | 7,239.07 | -2,248.32 | 54.10 |
| **BG** | 39,160.84 | 50,584.06 | 366.81 | 38,794.03 | 5,232.71 | 16,655.93 | 11,423.22 | 51.63 |
| **GR** | 61,423.85 | 51,219.40 | 864.72 | 60,559.14 | 11,898.18 | 1,693.73 | -10,204.45 | 58.83 |
| **HR** | 22,058.88 | 14,972.52 | 60.17 | 21,998.70 | 12,265.34 | 5,178.98 | -7,086.36 | 54.98 |
| **HU** | 47,200.05 | 40,049.87 | 0.00 | 47,200.05 | 14,053.66 | 6,903.48 | -7,150.18 | 55.29 |
| **KS** | 8,221.60 | 12,069.76 | 0.00 | 8,221.60 | 3,368.39 | 7,216.55 | 3,848.16 | 54.27 |
| **ME** | 5,394.96 | 4,615.52 | 0.00 | 5,394.96 | 9,081.15 | 8,301.71 | -779.44 | 54.13 |
| **MK** | 11,332.27 | 10,706.90 | 42.29 | 11,289.98 | 9,414.05 | 8,788.68 | -625.37 | 54.08 |
| **RO** | 66,400.71 | 88,547.87 | 0.00 | 66,400.71 | 1,603.53 | 23,750.69 | 22,147.15 | 51.37 |
| **RS** | 44,385.84 | 35,623.29 | 91.22 | 44,294.62 | 24,448.50 | 15,685.94 | -8,762.56 | 54.13 |
| **SI** | 14,903.77 | 14,316.27 | 0.00 | 14,903.77 | 1,807.51 | 1,220.01 | -587.50 | 55.15 |
| **Total (GWh) / Average (€/MWh)** | **347,744.13** | **347,744.13** | **1,434.74** | **346,309.39** | **107,028.29** | **107,028.29** | **0.00** | **54.35** |

As this scenario does not include external markets, market price is determined only by marginal cost of generation. Average wholesale price in SEE region is 54.35 €/MWh, while the average load-weighted price used for 2030 electricity market price assumptions amounts to 54.41 €/MWh.

Average load-weighted price gives more influence to the size of the country (represented by load) when calculating average price in the region. Therefore, prices in each country have been multiplied by the load of the country, added together and divided by the total load in SEE region.

## 6.2 Main set of scenarios

### 6.2.1 Base Case scenario

Beside SEE region Base Case scenario includes three external markets (IT, TR and CE) with modelled links (IT-SI, CE-SI, CE-HU, TR-BG, TR-GR), existing HVDC Greece-Italy and with HVDC Montenegro-Italy (under construction).

Electricity generation in SEE region is depicted in Figure 66 and the total generation amounts to 351.88 TWh. The highest generation is in Romania what is expected considering the amount of installed capacities, while Montenegro has the lowest electricity generation. Regarding generation capacities type, TPPs have the highest share in total generation in SEE region (168.40 TWh or 48%), followed by HPPs (69.70 TWh or 20%) and nuclear power plants (67.09 TWh or 19%). Considerably smaller shares have variable renewable sources – wind (35.70 TWh or 10%) and solar (10.98 TWh or 3%), but in total almost 47 TWh in wind and solar certainly contributes to electricity generation (Figure 67).

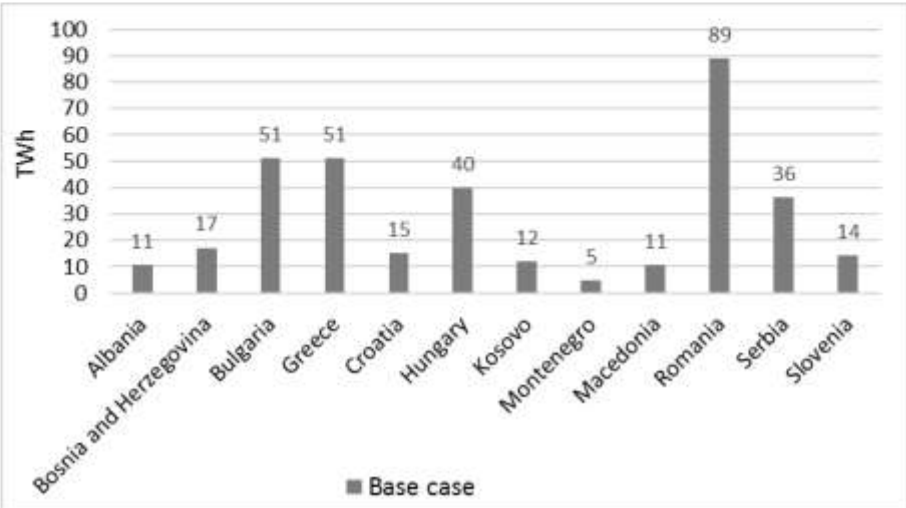


*Figure 66: Electricity generation in SEE region (Base Case)*

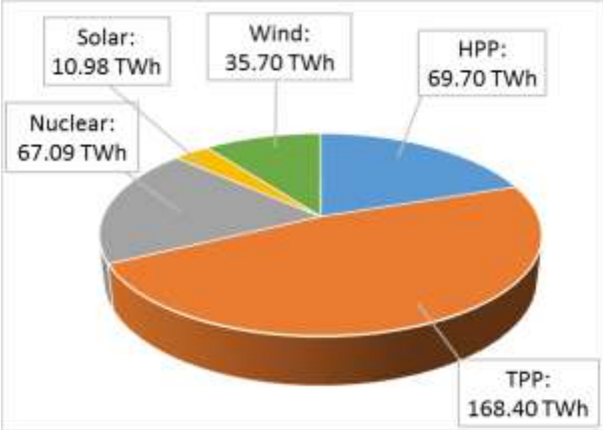


*Figure 67: Electricity generation mix in SEE region (Base Case)*

Electricity generation mix by country is presented in the following table. In most countries TPPs have the highest share, except in Albania, Croatia and Montenegro where HPPs have the highest share, and except in Hungary and Slovenia where nuclear electricity generation dominates. The least diversified generation mix has Kosovo where 95% of electricity generation comes from TPPs.

*Table 20: Electricity generation mix in SEE region by country (Base Case)*

| Yearly generation (TWh) | Albania | Bosnia and Herz-egovina | Bulgaria | Greece | Croatia | Hungary | Kosovo | Monte-negro | Mace-donia | Romania | Serbia | Slovenia | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HPP** | 10.19 | 5.04 | 3.62 | 7.62 | 8.11 | 0.00 | 0.20 | 3.03 | 2.23 | 14.95 | 10.81 | 3.92 | **69.70** |
| **TPP** | 0.00 | 10.34 | 27.39 | 23.53 | 4.26 | 10.19 | 11.53 | 1.19 | 8.05 | 43.65 | 23.93 | 4.34 | **168.40** |
| **Nuclear** | 0.00 | 0.00 | 14.43 | 0.00 | 0.00 | 28.19 | 0.00 | 0.00 | 0.00 | 18.99 | 0.00 | 5.49 | **67.09** |
| **Solar** | 0.12 | 0.11 | 2.35 | 5.07 | 0.29 | 0.08 | 0.04 | 0.03 | 0.05 | 2.54 | 0.03 | 0.27 | **10.98** |
| **Wind** | 0.43 | 1.62 | 3.51 | 14.78 | 2.59 | 1.46 | 0.30 | 0.31 | 0.33 | 8.73 | 1.33 | 0.30 | **35.70** |
| **TOTAL** | **10.74** | **17.11** | **51.30** | **50.99** | **15.24** | **39.93** | **12.07** | **4.57** | **10.66** | **88.85** | **36.10** | **14.31** | **351.88** |

Weekly generation for four typical weeks (3rd week of January, April, July and October) is illustrated in the following figures (Figure 68 to Figure 71). Romania expectedly has the highest generation values in all presented weeks and generation values are not so influenced with hydrologic conditions (winter/summer months) due to high share of TPPs. Effect of hydrologic conditions is more visible in countries with higher share of HPPs, for instance Albania.

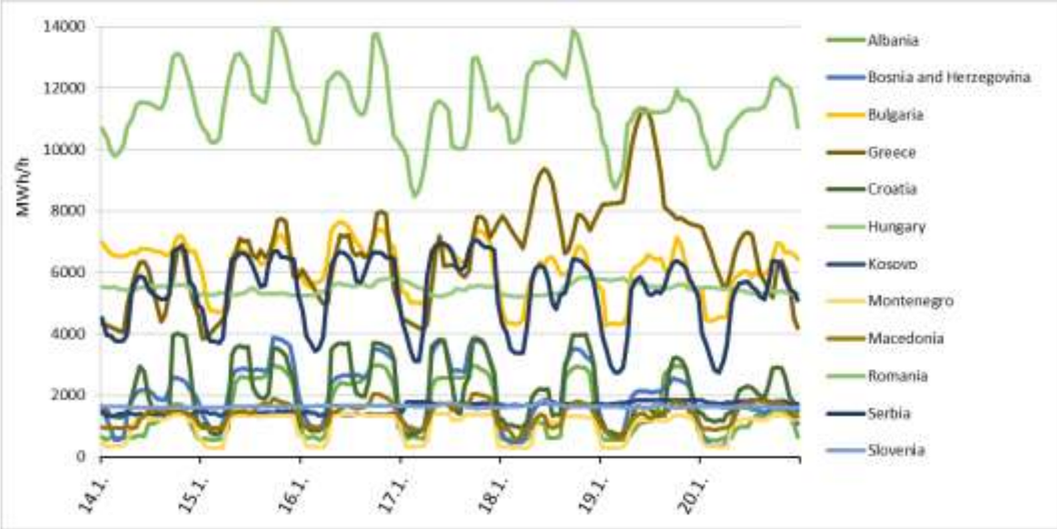


*Figure 68: Electricity generation in 3rd week of January (Base Case)*

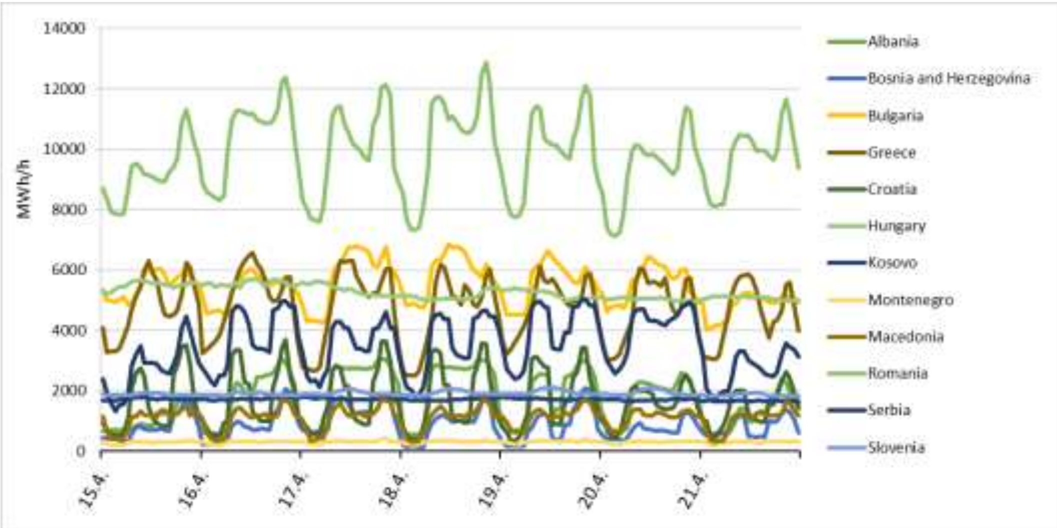


*Figure 69: Electricity generation in 3rd week of April (Base Case)*

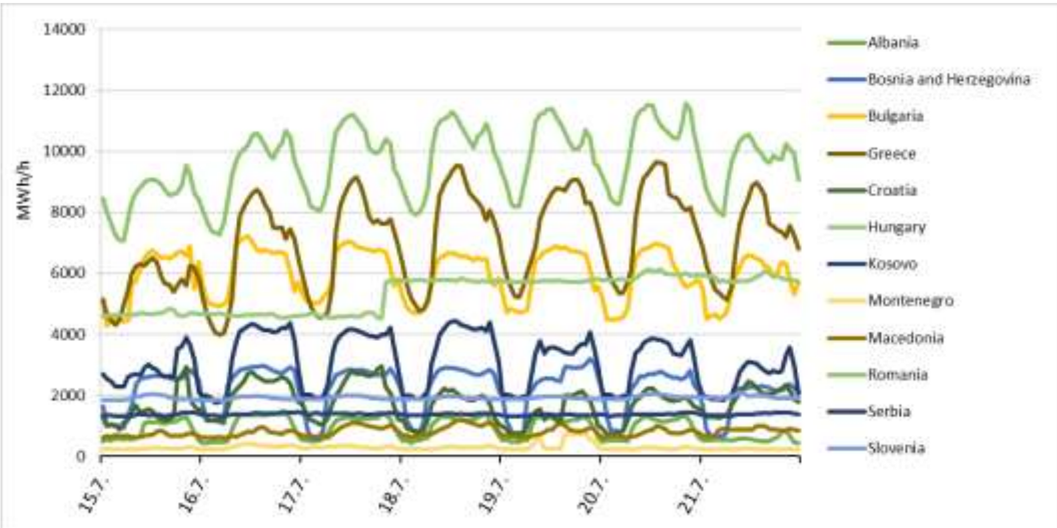


*Figure 70: Electricity generation in 3rd week of July (Base Case)*

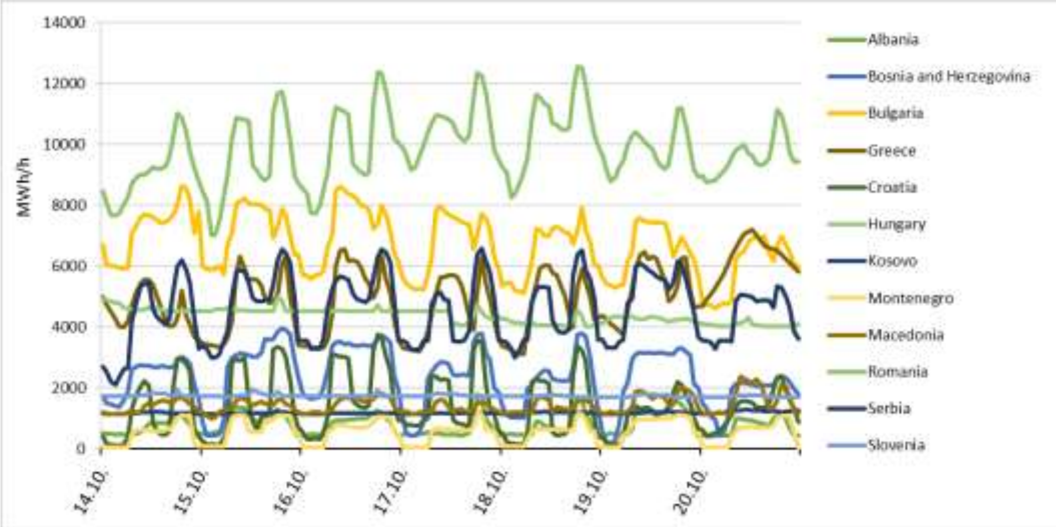


*Figure 71: Electricity generation in 3rd week of October (Base Case)*

Electricity balances i.e. yearly load, generation and exchange values, with resulting average wholesale market price for each SEE country in Base Case scenario are given in Table 21. Romania and Bulgaria have the highest net interchange value meaning they are the main net exporters in SEE region, while Greece is a significant net importer. Total sum of net interchange in SEE region is not zero since this scenario includes external markets. Market price is determined by marginal cost of generation and price on external markets. The highest average price is in Greece (60.47 €/MWh), while the lowest is in the main exporting country Romania (53.79 €/MWh). Average market price in SEE region amounts to 56.31 €/MWh in this scenario.

*Table 21: Electricity balances of SEE countries (Base Case)*

| Country | Load (GWh) | Generation (GWh) | Pump Load (GWh) | Customer Load (GWh) | Imports (GWh) | Exports (GWh) | Net Interchange (GWh) | Price (€/MWh) |
|---|---|---|---|---|---|---|---|---|
| **AL** | 10,791.50 | 10,741.15 | 0.00 | 10,791.50 | 4,407.59 | 4,357.24 | -50.35 | 56.72 |
| **BA** | 16,491.08 | 17,113.18 | 30.77 | 16,460.31 | 7,486.61 | 8,108.71 | 622.11 | 56.41 |
| **BG** | 39,555.08 | 51,301.16 | 761.05 | 38,794.03 | 8,832.56 | 20,578.64 | 11,746.09 | 54.22 |
| **GR** | 61,440.22 | 50,994.07 | 881.08 | 60,559.14 | 16,137.62 | 5,691.48 | -10,446.15 | 60.47 |
| **HR** | 22,072.06 | 15,242.53 | 73.36 | 21,998.70 | 12,797.99 | 5,968.46 | -6,829.53 | 56.63 |
| **HU** | 47,200.05 | 39,926.87 | 0.00 | 47,200.05 | 17,386.41 | 10,113.23 | -7,273.18 | 55.36 |
| **KS** | 8,221.60 | 12,071.32 | 0.00 | 8,221.60 | 3,662.44 | 7,512.15 | 3,849.71 | 56.55 |
| **ME** | 5,394.96 | 4,567.34 | 0.00 | 5,394.96 | 10,725.94 | 9,898.32 | -827.62 | 56.34 |
| **MK** | 11,354.79 | 10,662.71 | 64.81 | 11,289.98 | 9,888.59 | 9,196.51 | -692.08 | 56.24 |
| **RO** | 66,400.71 | 88,851.46 | 0.00 | 66,400.71 | 1,346.38 | 23,797.13 | 22,450.75 | 53.79 |
| **RS** | 44,414.64 | 36,096.94 | 120.02 | 44,294.62 | 23,281.98 | 14,964.27 | -8,317.71 | 56.30 |
| **SI** | 14,903.77 | 14,310.81 | 0.00 | 14,903.77 | 10,390.00 | 9,797.04 | -592.96 | 56.70 |
| **Total (GWh) / Average (€/MWh)** | **348,240.47** | **351,879.55** | **1,931.09** | **346,309.39** | **126,344.10** | **129,983.18** | **3,639.08** | **56.31** |

Total load includes customer load (demand) and pump load for pumped storage HPPs, so customer load has the same values in all scenarios since it is a predefined input time series of demand. Pump load values change in scenarios based on the operation of pump storage HPPs in pumping mode. Impact of pump storage HPPs on system load can be explained in the following examples of Bulgarian and Greek load, as Bulgaria and Greece have the highest pump load values in SEE region.

According to the 2030 Vision 1 from TYNDP 2014, Bulgarian demand is set to 38,794 GWh and that is presented as the customer load. In Bulgaria three pumped storage HPPs are modelled in 2030 – Belmeken, Chaira and Orfei, with the total installed output of 884 MW in pumping mode. Pump load for HPPs operation in pumping mode amounts to 761 GWh what results in the total system load of 39,555 GWh, as presented in Table 22.

*Table 22: Bulgarian yearly load (Base Case)*

| Bulgarian load | Yearly load (GWh) |
|---|---|
| Customer load | 38,794 |
| Pump load | 761 |
| **Total load** | **39,555** |

More details are given in hourly load values for 3rd week of January (Figure 72) and 3rd week of July (Figure 73). Load and customer load overlap most of the time meaning their values are equal, except in the periods when pumped storage HPPs operate in pumping mode (usually during night hours) and thus increase the total load value (presented by blue line in figures).

In the market model the goal is to maximize profit of all generating resources to meet a given power demand with possibilities to import and export electricity, taking into account all operational constraints. Hence, pumped storage HPPs operation depends on numerous factors, primarily on market prices, but also on operational constraints, power demand (load) and possibilities to export or import electricity.

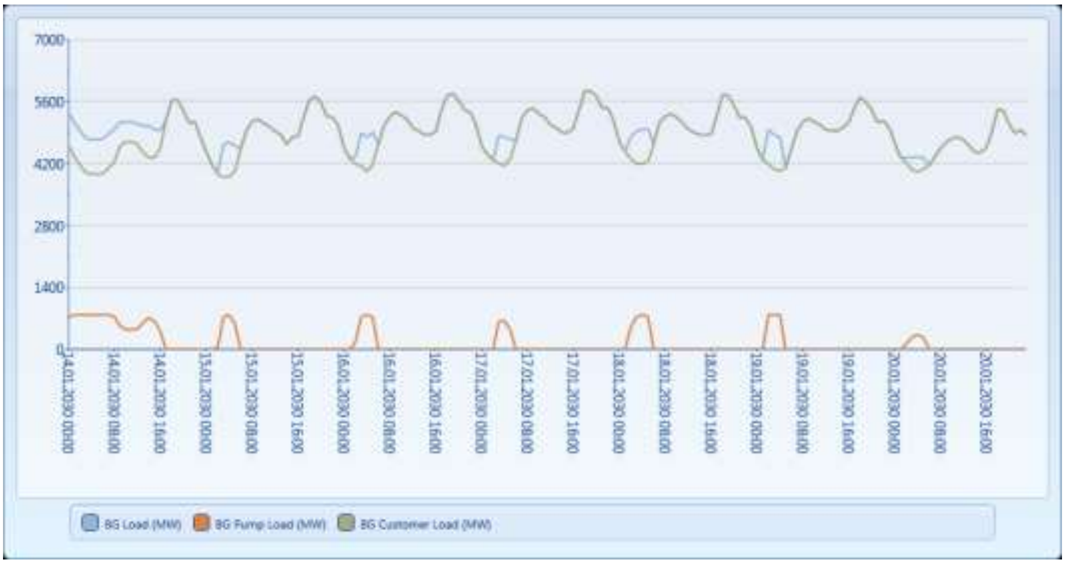


*Figure 72: Bulgarian load in 3rd week of January (Base Case)*

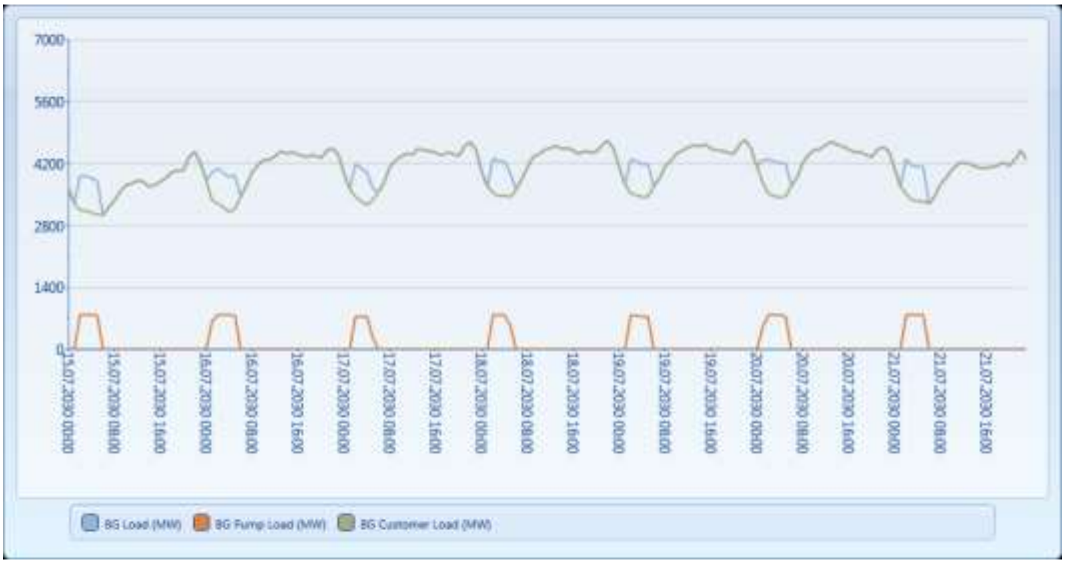


*Figure 73: Bulgarian load in 3rd week of July (Base Case)*

Example of operation in pumping mode is given for two pumped storage HPPs Belmeken and Chaira which use Belmeken storage as upper reservoir. Location of PSHPP Belmeken and scheme of surrounding hydropower system is shown in the following figure.

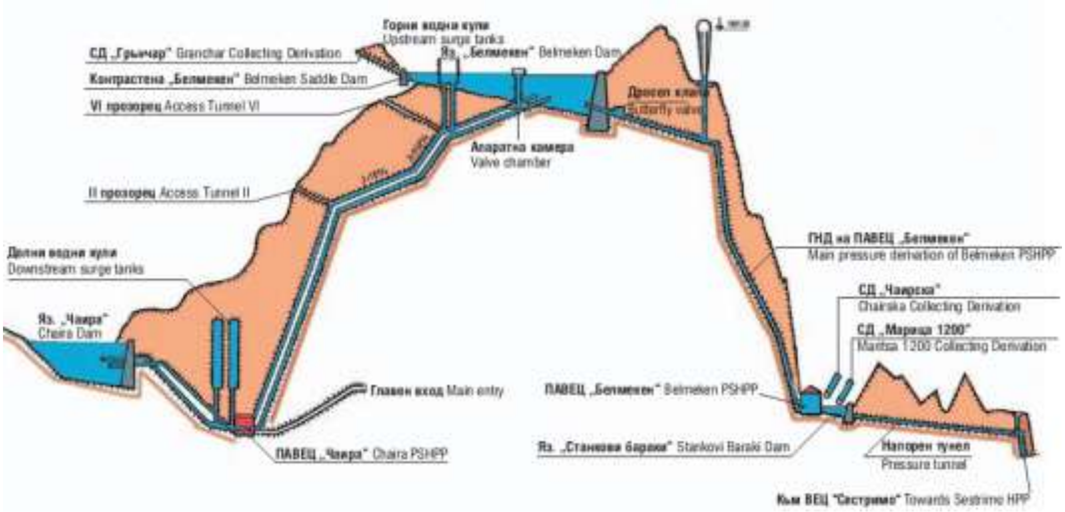


*Figure 74: Belmeken - Sestrimo cascade[11]*

Belmeken storage size (max volume) and volume in every hour (end volume) in GWh are shown on left ordinate scale. Right ordinate scale presents values for storage inflow, release, natural inflow and pump load in MW. Storage size is set to 237 GWh, while end volume in certain hour changes according to reservoir inflow and release. Inflow represents the sum of natural inflow and pump load when pumped storage HPPs (in this case PSHPP Belmeken and PSHPP Chaira) pump water to the upper reservoir. Release from storage refers to generation release when HPPs are operating in generating mode. Maximum possible generation output amounts to 1,215 MW when both PSHPP Belmeken and PSHPP Chaira are generating electricity. Simulation results for 3rd week of January are depicted in Figure 75.

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[11] NEK, Hydro Power Cascades and Dams: http://www.nek.bg/images/content/pdf/2-hpcd.pdf


*Figure 75: Belmeken storage in 3rd week of January (Base Case)*

Similarly to Bulgarian example, customer load in Greece refers to Greek demand which is set to 60,559 GWh (according to the 2030 Vision 1 from TYNDP 2016). Greek generation capacities are aggregated per technology clusters, thus pumped storage HPPs are modelled as one generating unit with total installed output of 1,579 MW in pumping mode. Pump load for HPPs operation in pumping mode amounts to 881 GWh what results in the total system load of 61,440 GWh, as presented in Table 23.

*Table 23: Greek yearly load (Base Case)*

| Greek load | Yearly load (GWh) |
|---|---|
| Customer load | 60,559 |
| Pump load | 881 |
| **Total load** | **61,440** |

More details are given in hourly load values for 3rd week of January, April, July and October (Figure 76 to Figure 79). As in Bulgaria, load and customer load overlap most of the time, except in the periods when pumped storage HPP operates in pumping mode and thus increase the total load value.

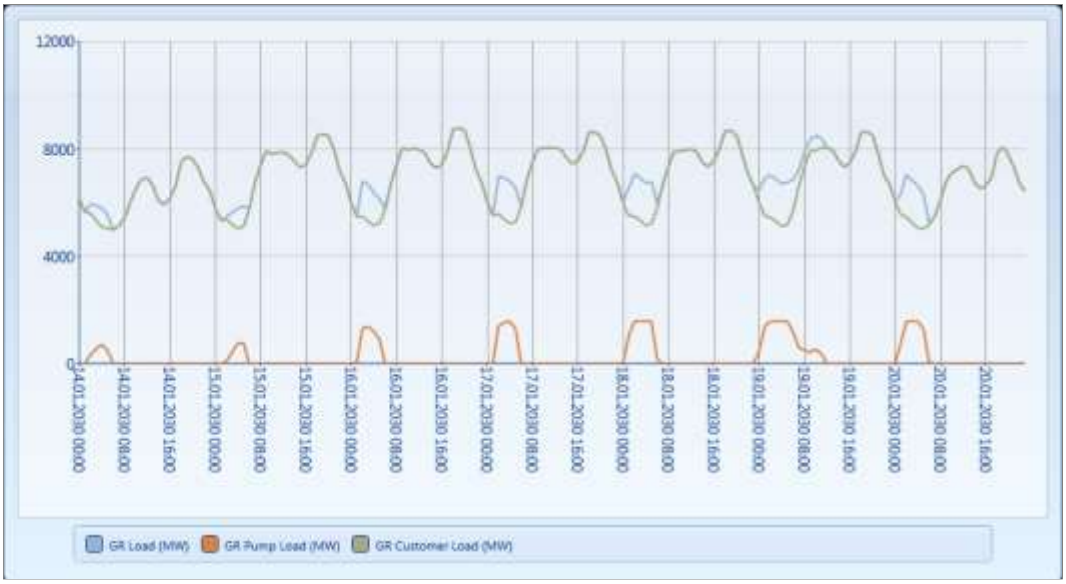



*Figure 76: Greek load in 3rd week of January (Base Case)*

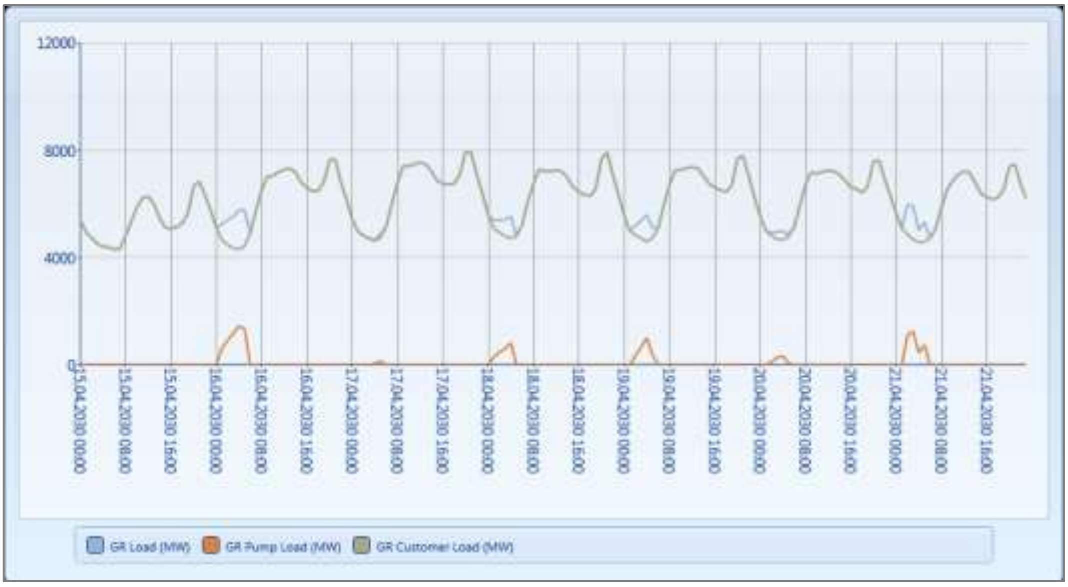



*Figure 77: Greek load in 3rd week of April (Base Case)*


*Figure 78: Greek load in 3rd week of July (Base Case)*

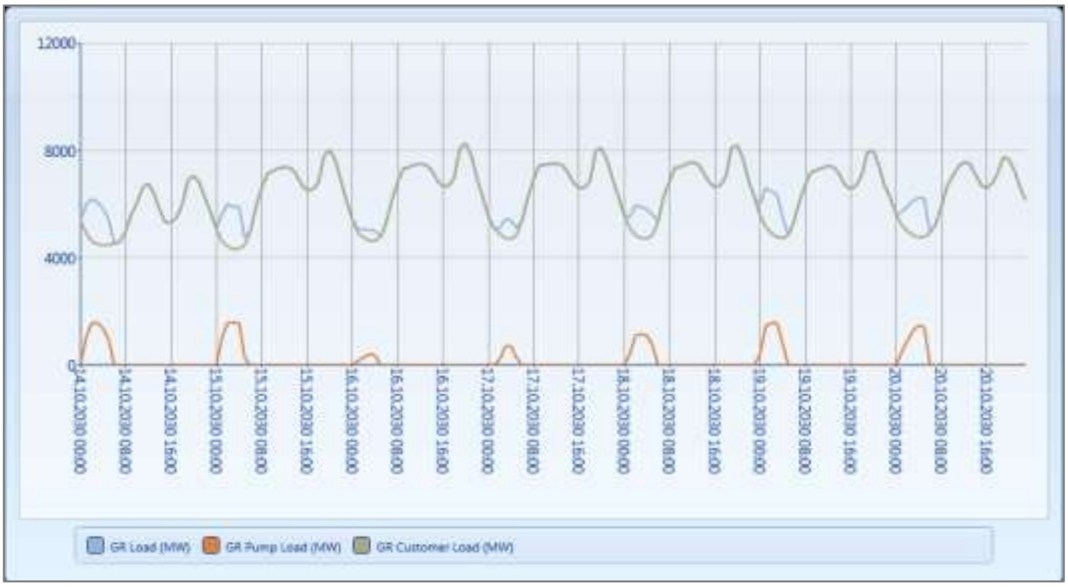



*Figure 79: Greek load in 3rd week of October (Base Case)*

When observing differences among SEE countries the important factor is generation cost, for which yearly simulation results are presented in Table 24. Market price is determined by marginal cost of generation and price on external markets, and calculation of generation costs themselves is based on variable cost including fuel and O&M cost of generating units.

Average generation costs in SEE region amount to 13.04 €/MWh. The lowest generation cost is in Albania (4.74 €/MWh) what is expected considering the high share of HPPs in generation mix, while the highest is in Macedonia (22 €/MWh) where TPPs have the highest share and in particular gas TPPs (high fuel costs). Total average generation costs, which include also carbon costs, amount to 20.71 €/MWh in SEE region. In terms of total average generation cost, Albania also has the lowest values, while Bosnia and Herzegovina has the highest (33.23 €/MWh) followed by Serbia (32.28 €/MWh). This is due to carbon cost which mostly affects countries with high share of coal-based TPPs.

*Table 24: Generation costs of SEE countries (Base Case)*

| Country | Generation (GWh) | Generation Cost (M€) | Emissions Cost (M€) | Total Generation Cost (M€) | Average Generation Cost (€/MWh) | Total Average Generation Cost (€/MWh) |
|---|---|---|---|---|---|---|
| **AL** | 10,741.15 | 50.93 | 0.00 | 50.93 | 4.74 | 4.74 |
| **BA** | 17,113.18 | 345.54 | 223.18 | 568.72 | 20.19 | 33.23 |
| **BG** | 51,301.16 | 765.37 | 426.55 | 1,191.93 | 14.92 | 23.23 |
| **GR** | 50,994.07 | 456.79 | 367.11 | 823.90 | 8.96 | 16.16 |
| **HR** | 15,242.53 | 164.97 | 60.45 | 225.42 | 10.82 | 14.79 |
| **HU** | 39,926.87 | 512.34 | 124.46 | 636.80 | 12.83 | 15.95 |
| **KS** | 12,071.32 | 99.03 | 208.50 | 307.54 | 8.20 | 25.48 |
| **ME** | 4,567.34 | 47.27 | 19.27 | 66.54 | 10.35 | 14.57 |
| **MK** | 10,662.71 | 234.54 | 99.65 | 334.19 | 22.00 | 31.34 |
| **RO** | 88,851.46 | 1,211.68 | 642.38 | 1,854.06 | 13.64 | 20.87 |
| **RS** | 36,096.94 | 693.94 | 471.41 | 1,165.34 | 19.22 | 32.28 |
| **SI** | 14,310.81 | 151.16 | 76.67 | 227.84 | 10.56 | 15.92 |
| **Total (GWh) (M€) / Average (€/MWh)** | **351,879.55** | **4,733.55** | **2,719.65** | **7,453.20** | **13.04** | **20.71** |

In Base Case scenario there are 28 cross-border lines and 2 submarine HVDC cables (one existing GR-IT and one under construction ME-IT). Yearly cross-border exchange and congestions results are given in the following tables. Highest cross-border exchange has Serbia, i.e. 38,246 GWh (14,964 GWh from Serbia to neighboring countries and 23,282 GWh in the opposite direction). Cross-border congestions represent the number of hours in a year flow on interconnections equals NTC. Significant congestions can be noticed, especially on the BG-GR border and HVDC cable ME-IT, but only in one direction – to Greece and to Italy, respectively.

*Table 25: Cross-border exchange (Base Case)*

| Base Case | Flow (GWh) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** | **Total** |
| **AL** | - | | | 1639 | | | 989 | 1206 | 523 | | | | | | | **4357** |
| **BA** | | - | | | 2574 | | | 4984 | | | 551 | | | | | **8109** |
| **BG** | | | - | 5975 | | | | | 3950 | 886 | 5411 | | | 4357 | | **20579** |
| **GR** | 316 | | 296 | - | | | | | 618 | | | | 2808 | 1653 | | **5691** |
| **HR** | | 1602 | | | - | 1275 | | | | | 584 | 2508 | | | | **5968** |
| **HU** | | | | | 5932 | - | | | | 434 | 2725 | | | | 1022 | **10113** |
| **KS** | 1087 | | | | | | - | 1354 | 3119 | | 1952 | | | | | **7512** |
| **ME** | 714 | 410 | | | | | 616 | - | | | 1365 | | 6793 | | | **9898** |
| **MK** | 2290 | | 244 | 5692 | | | 443 | | - | | 529 | | | | | **9197** |
| **RO** | | | 5978 | | | 7653 | | | | - | 10166 | | | | | **23797** |
| **RS** | | 5475 | 216 | | 1914 | 1979 | 1615 | 2060 | 1679 | 27 | - | | | | | **14964** |
| **SI** | | | | | 2379 | | | | | | | - | 6906 | | 512 | **9797** |
| **IT** | | | | 1142 | | | | 1122 | | | | 929 | - | | | **3194** |
| **TR** | | | 2099 | 1690 | | | | | | | | | | - | | **3788** |
| **CE** | | | | | | 6479 | | | | | | 6953 | | | - | **13432** |
| **Total** | **4408** | **7487** | **8833** | **16138** | **12798** | **17386** | **3662** | **10726** | **9889** | **1346** | **23282** | **10390** | **16507** | **6010** | **1535** | |

*Table 26: Cross-border congestions (Base Case)*

| Base Case | Hours Congested (h) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** |
| **AL** | - | | | 6044 | | | 163 | 715 | 496 | | | | | | |
| **BA** | | - | | | 603 | | | 211 | | | 36 | | | | |
| **BG** | | | - | 6495 | | | | | 4576 | 47 | 4522 | | | 5237 | |
| **GR** | 828 | | 130 | - | | | | | 385 | | | | 5405 | 4033 | |
| **HR** | | 48 | | | - | 421 | | | | | 160 | 728 | | | |
| **HU** | | | | | 2713 | - | | | | 23 | 2581 | | | | 739 |
| **KS** | 33 | | | | | | - | 408 | 29 | | 335 | | | | |
| **ME** | 383 | 0 | | | | | 144 | - | | | 34 | | 6432 | | |
| **MK** | 422 | | 144 | 5634 | | | 0 | | - | | 778 | | | | |
| **RO** | | | 1284 | | | 2881 | | | | - | 5397 | | | | |
| **RS** | | 116 | 20 | | 1273 | 1294 | 303 | 81 | 453 | 0 | - | | | | |
| **SI** | | | | | 478 | | | | | | | - | 6316 | | 261 |
| **IT** | | | | 2081 | | | | 913 | | | | 632 | - | | |
| **TR** | | | 2112 | 3758 | | | | | | | | | | - | |
| **CE** | | | | | | 5790 | | | | | | 6376 | | | - |

Graphical representation of the most congested borders, i.e. interconnections with more than 65% of hours congested per year, is given in the following figure.

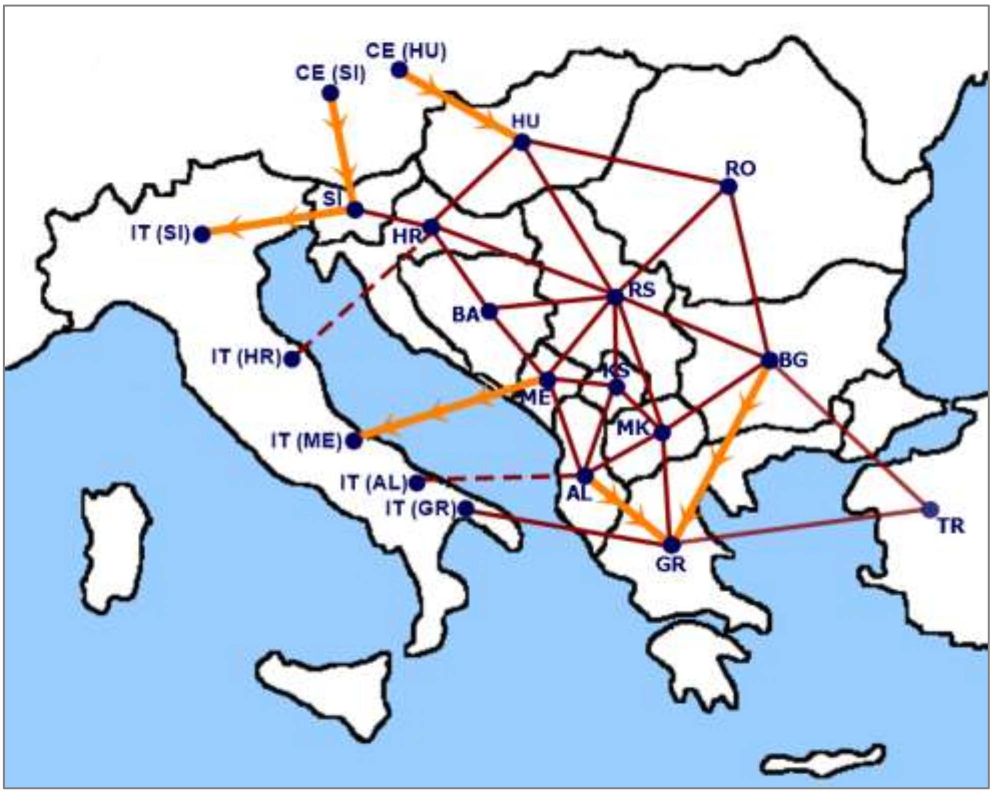



*Figure 80: Graphical representation of the most congested borders (Base Case)*

More details regarding HVDC cables flow are given in hourly values for 3rd week of January, April, July and October in the following figures (Figure 81 to Figure 84). As already mentioned, Base Case includes two HVDC cables IT-GR and IT-ME. Maximum allowed flow for IT-GR HVDC cable is set to 500 MW in both directions, while for IT-ME HVDC cable it is set to 1,000 MW. In all presented weeks flow is mostly directed toward Italy, what is especially visible in July when both HVDC cables show maximum allowed flow practically during the entire presented week.

Figure 81: HVDC cables flow in 3rd week of January (Base Case)

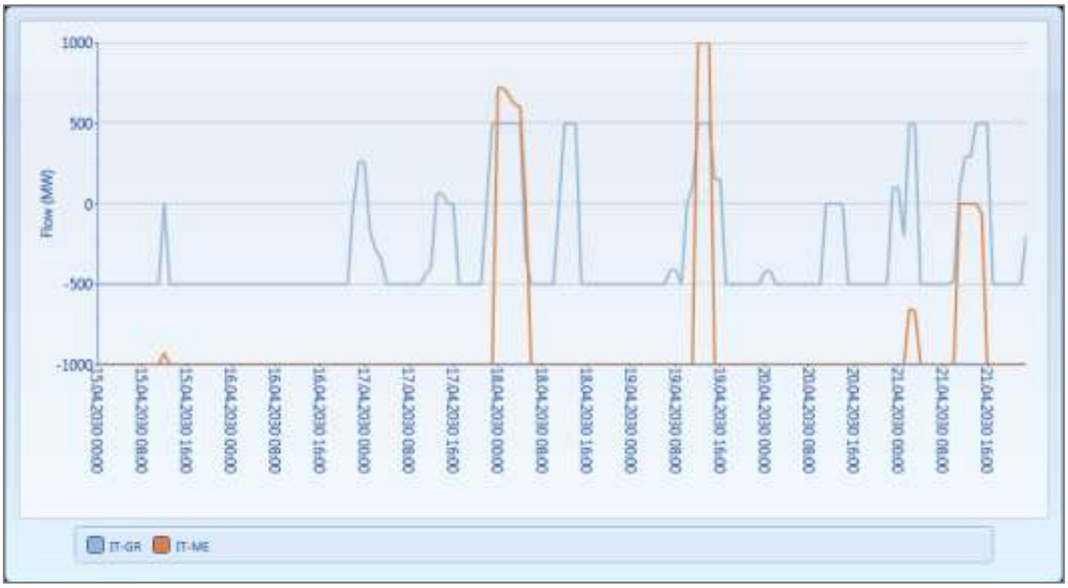


Figure 82: HVDC cables flow in 3rd week of April (Base Case)

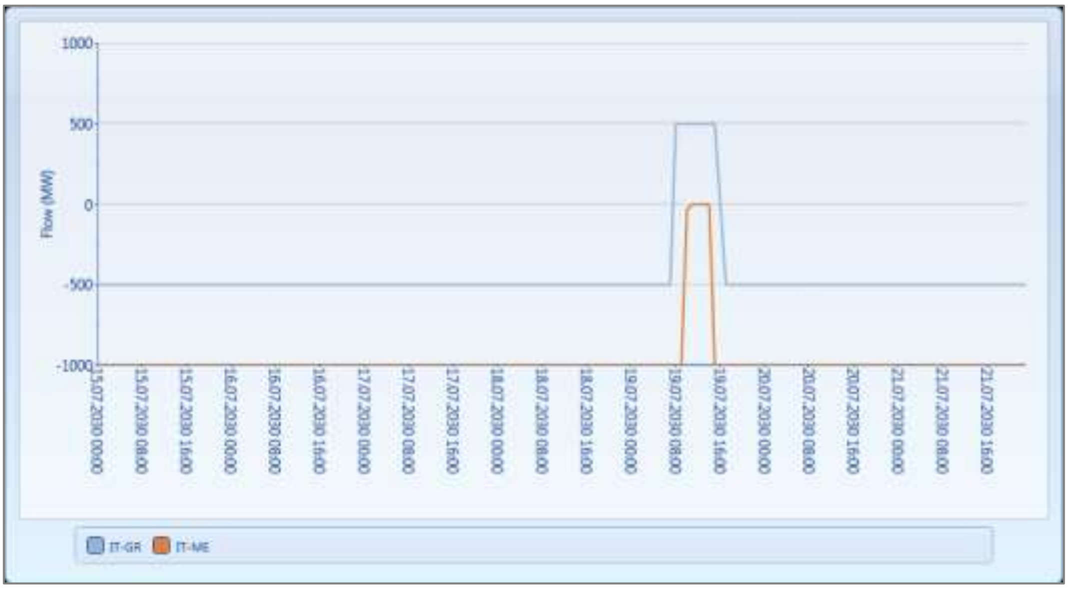



*Figure 83: HVDC cables flow in 3rd week of July (Base Case)*

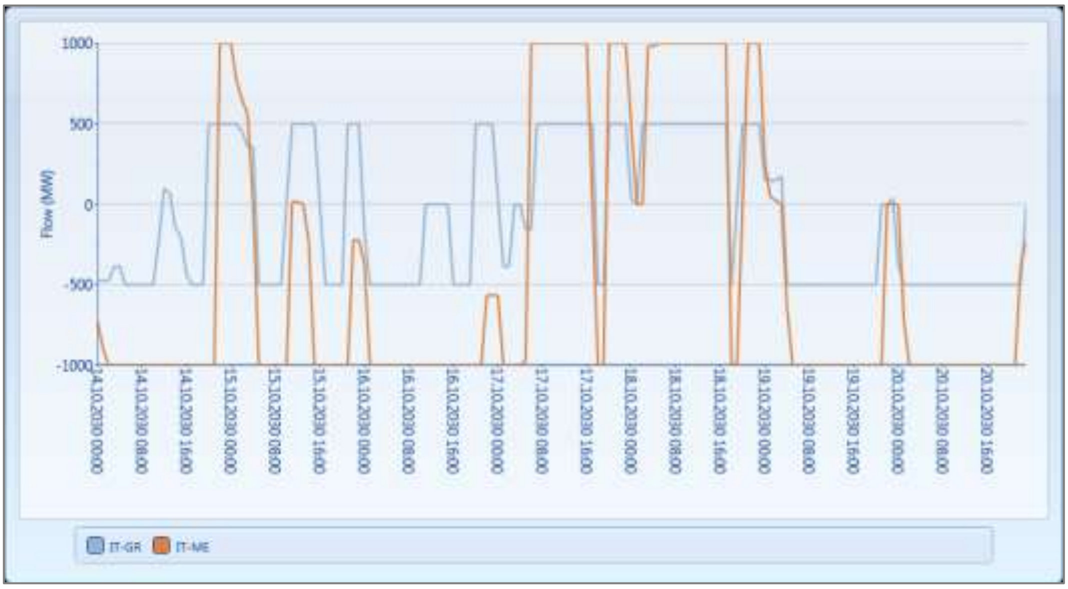



*Figure 84: HVDC cables flow in 3rd week of October (Base Case)*

Yearly values for exports, imports and net interchange for SEE countries are previously shown in Table 21, but below are presented also for three external markets and in more details, not only on yearly basis but also for four selected weeks.

Exports and imports values are depicted in the Figure 85, and net interchange in Figure 86. Export refers to positive values, while import refers to negative values. In SEE region Greece is the highest net importer and Romania is the highest net exporter, what is easier to observe from Figure 86. Figure 85 shows that the highest power transit is through Serbia, because of the high import and export values. Regarding external markets, the highest power transit is to Italian market due to high wholesale market price in Italy (66.11 €/MWh is the assumed average price in 2030) compared to prices in SEE region. Thus while Italy mostly imports electricity from SEE region, Central Europe mostly exports electricity to SEE region what is expected considering assumed average price in 2030 in the amount of 45.43 €/MWh.

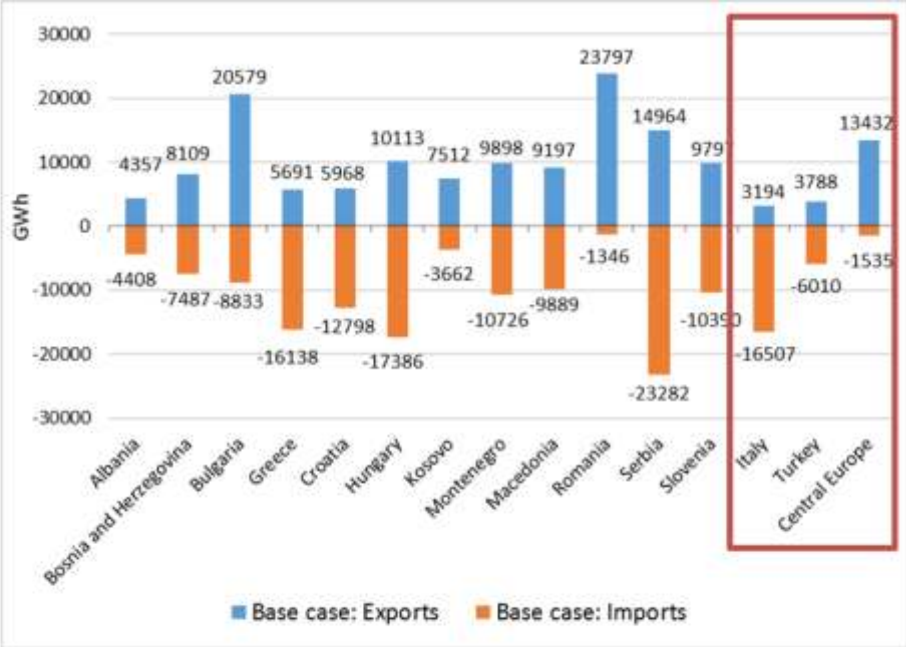



*Figure 85: Imports and exports (Base Case)*

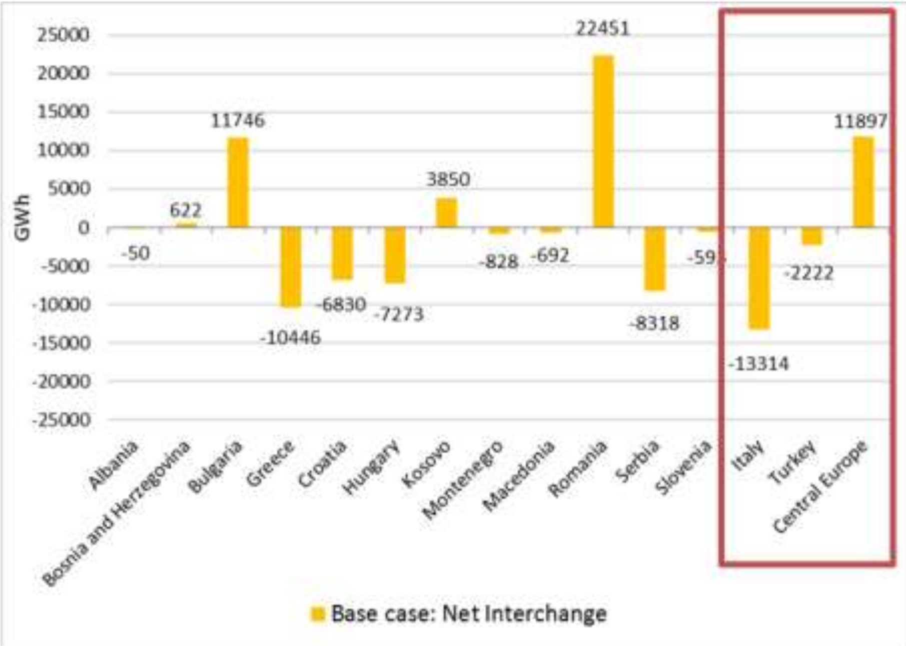



*Figure 86: Net interchange (Base Case)*

Weekly imports and exports simulation results for Base Case are given in the following figures for 3rd week of January, April, July and October, but big differences cannot be noticed.

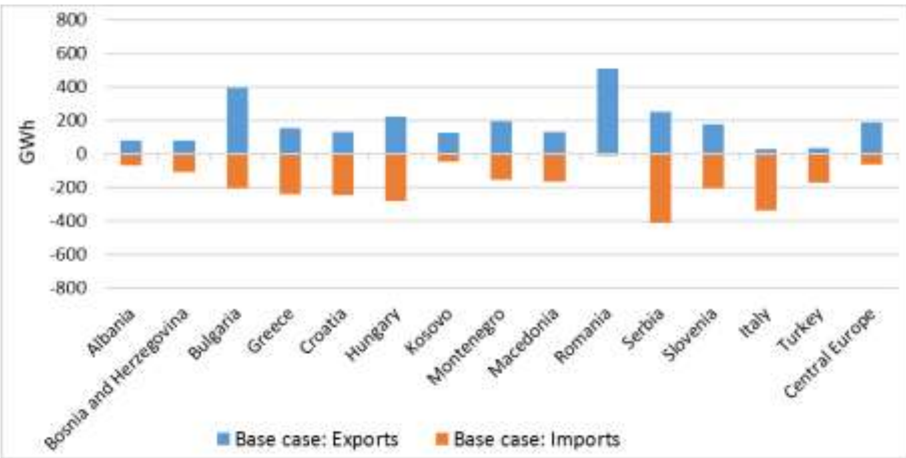



*Figure 87: Imports and exports in 3rd week of January (Base Case)*

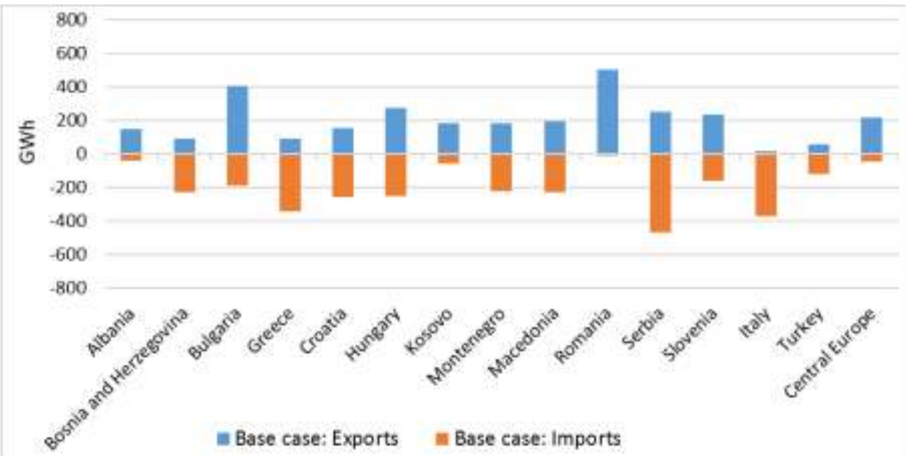



*Figure 88: Imports and exports in 3rd week of April (Base Case)*

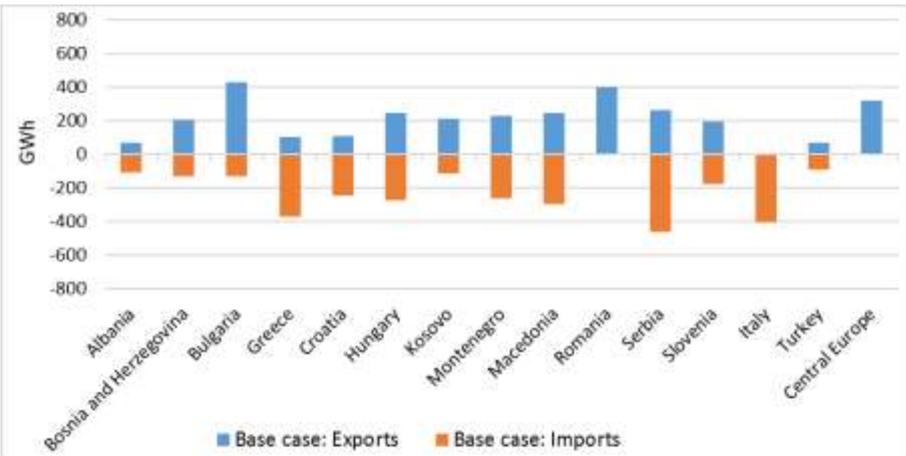



*Figure 89: Imports and exports in 3rd week of July (Base Case)*

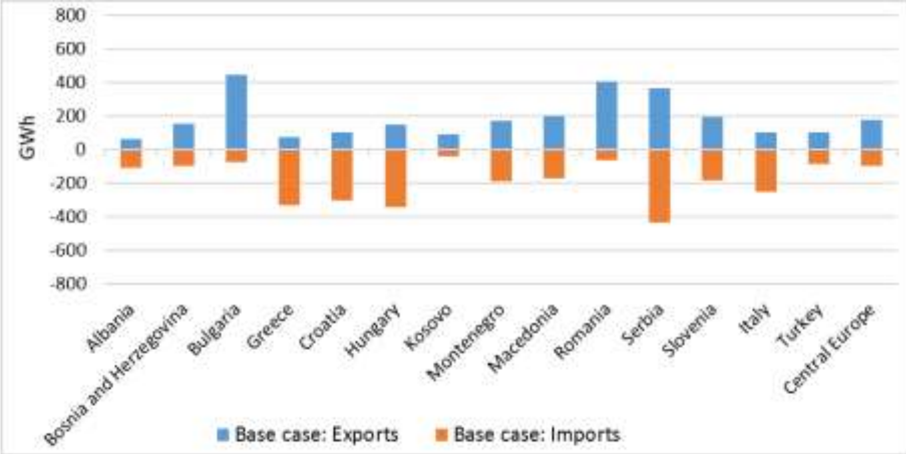



*Figure 90: Imports and exports in 3rd week of October (Base Case)*

In the following, more details on wholesale prices are presented for SEE countries and for external markets. As already mentioned, market price is determined by marginal cost of generation and price on external markets. Average SEE regional price is 56.31 €/MWh without taking into account external markets (Figure 91). Generally, wholesale electricity prices are harmonized in the region, but certain variations can be noticed. The highest prices are in Greece (60.47 €/MWh on average) and the lowest are in Romania (53.79 €/MWh). Average realized price on markets in Italy and Turkey is higher than SEE region average, while on market in Central Europe is significantly lower.

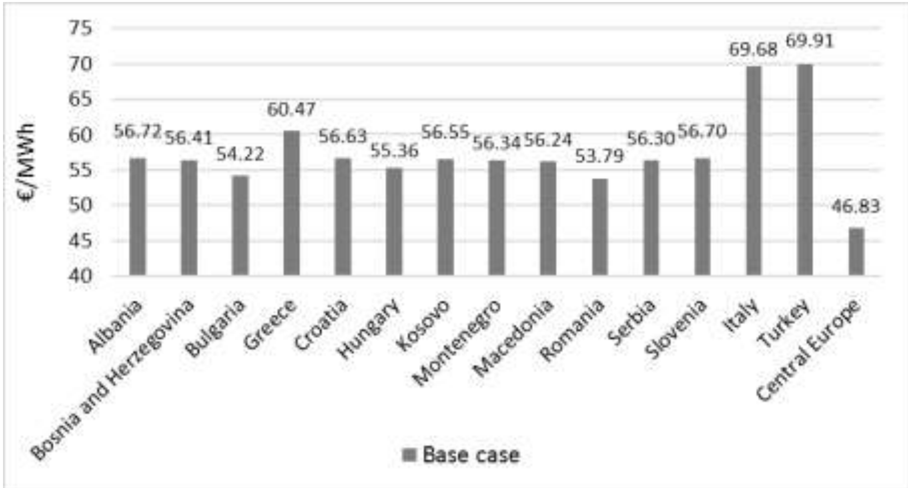



*Figure 91: Average wholesale prices (Base Case)*

Weekly average wholesale prices in SEE region and external markets for 3rd week of January, April, July and October are depicted from Figure 92 to Figure 95. In all presented weeks Greece has the highest weekly prices in SEE region, especially in July when it imports more electricity. Figure 94 also shows high average weekly price on market in Italy what is expected considering the input data for market model shown in Table 17.

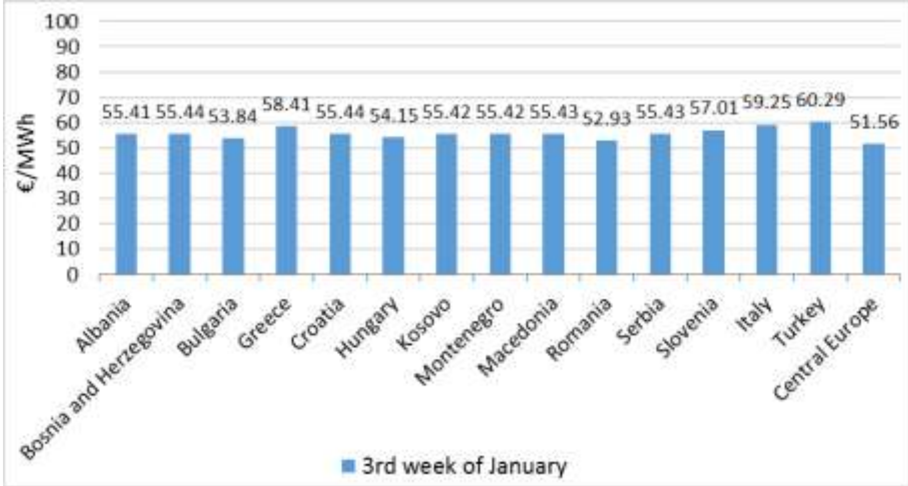



*Figure 92: Weekly average wholesale prices in 3rd week of January (Base Case)*

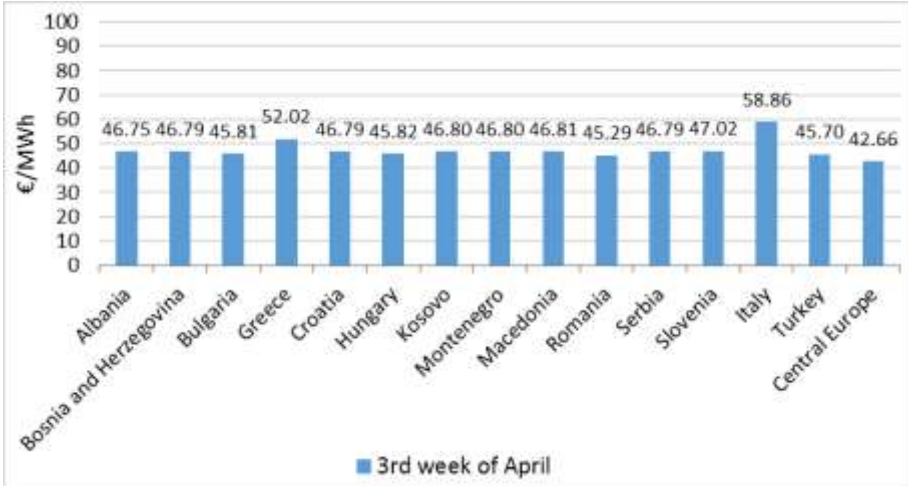



*Figure 93: Weekly average wholesale prices in 3rd week of April (Base Case)*

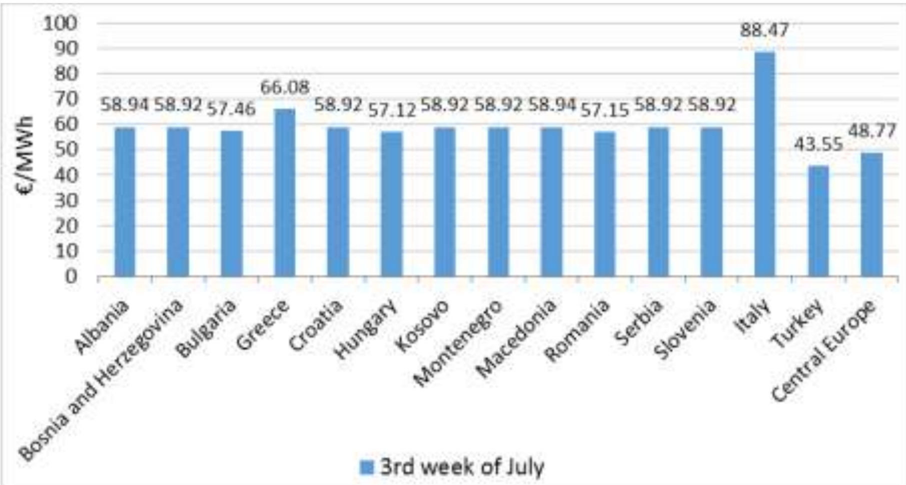



*Figure 94: Weekly average wholesale prices in 3rd week of July (Base Case)*

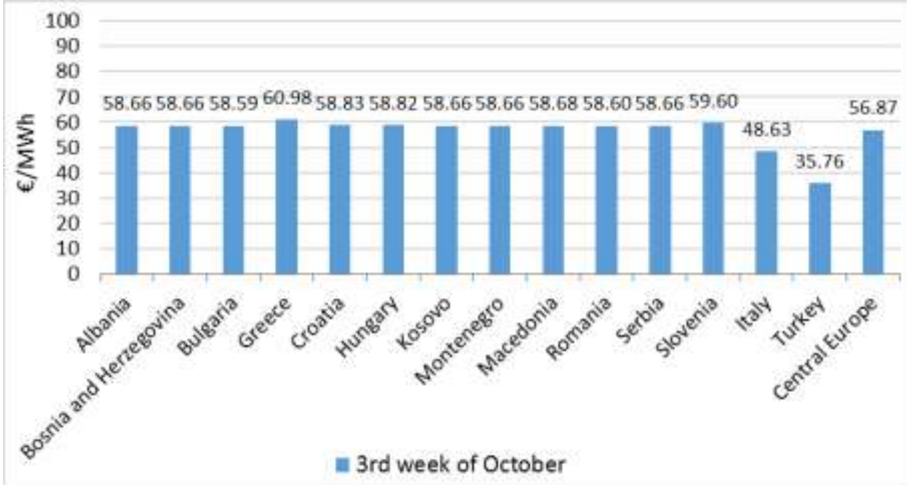



*Figure 95: Weekly average wholesale prices in 3rd week of October (Base Case)*

Market model simulation results provide hourly values for every modelled country, but here are selected three of them as an example of hourly prices variations – Bosnia and Herzegovina, Bulgaria and Greece. Hourly prices for 3rd week of January, April, July and October are presented in the following figures. Generally, prices in Greece are higher than in other two countries especially in peak hours, while prices in Bosnia and Herzegovina and Bulgaria often overlap.

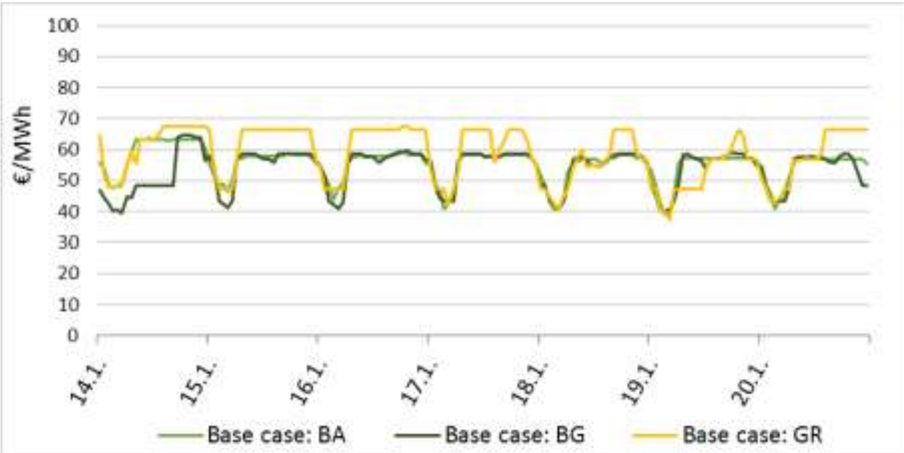



*Figure 96: Hourly wholesale prices in 3rd week of January (Base Case)*

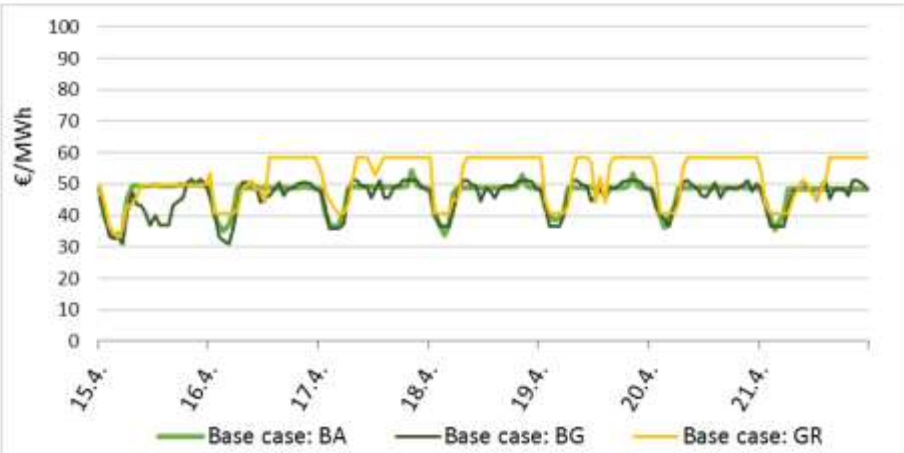



*Figure 97: Hourly wholesale prices in 3rd week of April (Base Case)*

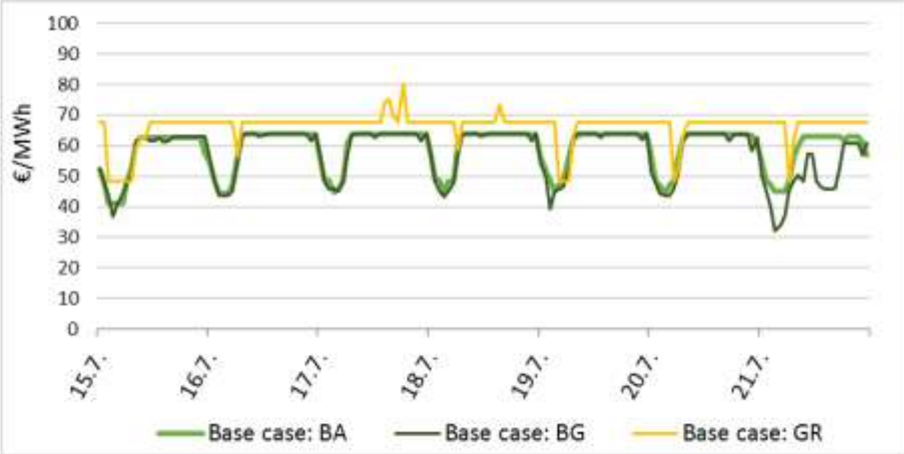



*Figure 98: Hourly wholesale prices in 3rd week of July (Base Case)*

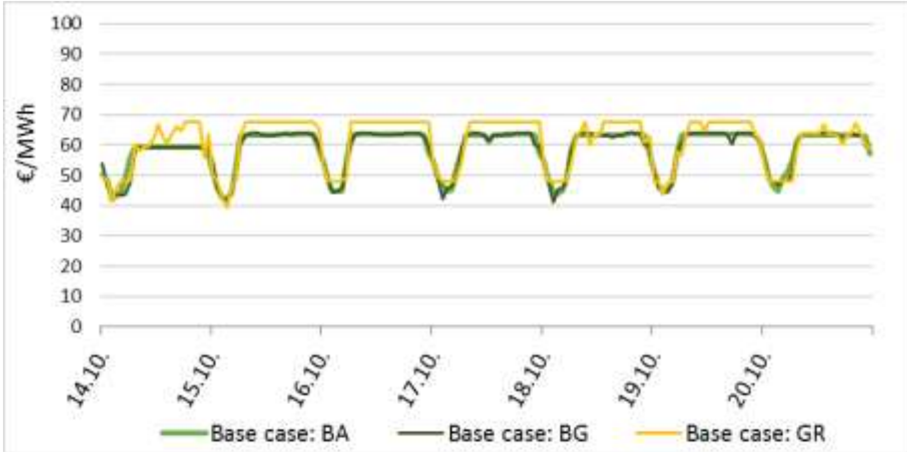



*Figure 99: Hourly wholesale prices in 3rd week of October (Base Case)*

### 6.2.2 Alternative Case scenario

Compared to Base Case, Alternative Case scenario includes two additional links to Italy – HVDC Croatia-Italy and HVDC Albania-Italy. Simulation results for electricity generation in SEE region are depicted in Figure 100 and the total generation amounts to 357.50 TWh. As in Base Case, the highest generation is in Romania, while Montenegro has the lowest electricity generation.

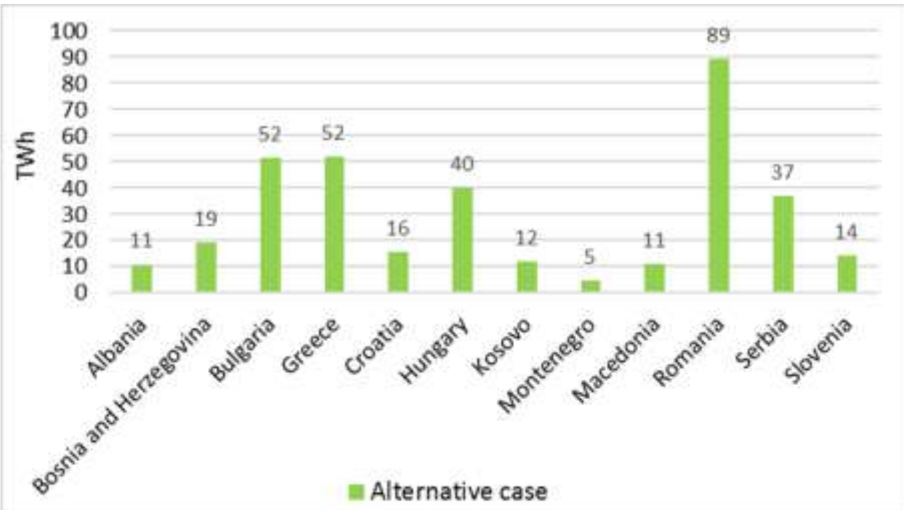



*Figure 100: Electricity generation in SEE region (Alternative Case)*

Total electricity generation is higher than in Base Case because generation from TPPs is increased due to higher exporting possibilities (two additional HVDC cables to Italy).

In electricity generation mix, TPPs have the highest share (173.52 TWh or 49%), followed by HPPs (70.22 TWh or 20%) and nuclear power plants (67.09 TWh or 19%). Wind and solar plants have the smallest shares in total electricity generation in SEE region. Since wind and solar generation is predefined using hourly time series of capacity factor during the year, electricity generation is the same as in Base Case. From wind is generated 35.70 TWh electricity (10% share), while from solar 10.98 TWh (3% share).

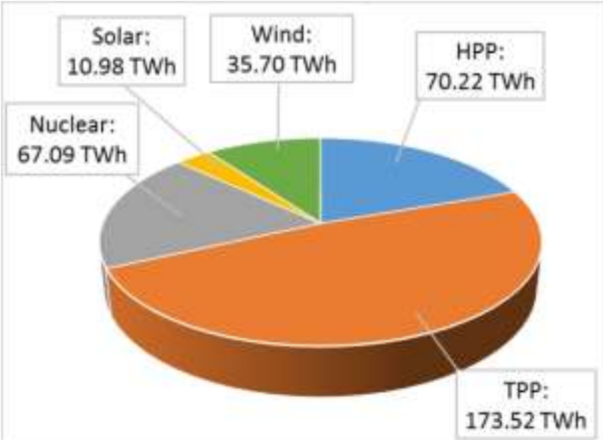



*Figure 101: Electricity generation mix in SEE region (Alternative Case)*

Electricity generation mix by country is presented in Table 27. Generation mix is similar as in Base Case, in most countries TPPs have the highest share. Compared to Base Case scenario results, electricity generation is increased in Bosnia and Herzegovina i.e. in its TPPs.

*Table 27: Electricity generation mix in SEE region by country (Alternative Case)*

| Yearly generation (TWh) | Albania | Bosnia and Herz-egovina | Bulgaria | Greece | Croatia | Hungary | Kosovo | Monte-negro | Mace-donia | Romania | Serbia | Slovenia | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **HPP** | 10.24 | 5.10 | 3.78 | 7.52 | 8.14 | 0.00 | 0.20 | 3.09 | 2.29 | 14.95 | 11.00 | 3.92 | **70.22** |
| **TPP** | 0.00 | 12.26 | 27.54 | 24.52 | 4.51 | 10.48 | 11.51 | 1.23 | 8.38 | 44.16 | 24.59 | 4.34 | **173.52** |
| **Nuclear** | 0.00 | 0.00 | 14.43 | 0.00 | 0.00 | 28.19 | 0.00 | 0.00 | 0.00 | 18.99 | 0.00 | 5.49 | **67.09** |
| **Solar** | 0.12 | 0.11 | 2.35 | 5.07 | 0.29 | 0.08 | 0.04 | 0.03 | 0.05 | 2.54 | 0.03 | 0.27 | **10.98** |
| **Wind** | 0.43 | 1.62 | 3.51 | 14.78 | 2.59 | 1.46 | 0.30 | 0.31 | 0.33 | 8.73 | 1.33 | 0.30 | **35.70** |
| **TOTAL** | **10.79** | **19.09** | **51.61** | **51.89** | **15.52** | **40.21** | **12.06** | **4.66** | **11.04** | **89.36** | **36.95** | **14.32** | **357.50** |

Weekly generation results for four typical weeks ($3^{rd}$ week of January, April, July and October) are presented in the following figures (Figure 102 to Figure 105). As in Base Case, Romania has the highest generation values in all presented weeks, while Montenegro has the lowest with a noticeable straight line depicting generation in April (Figure 103). In most countries generation significantly varies during day expect in Hungary and Slovenia. Reasons for this we can find in modelling approach (they are modelled aggregated per technology clusters), but also in generation mix since they both have nuclear power plants with no storage HPPs.

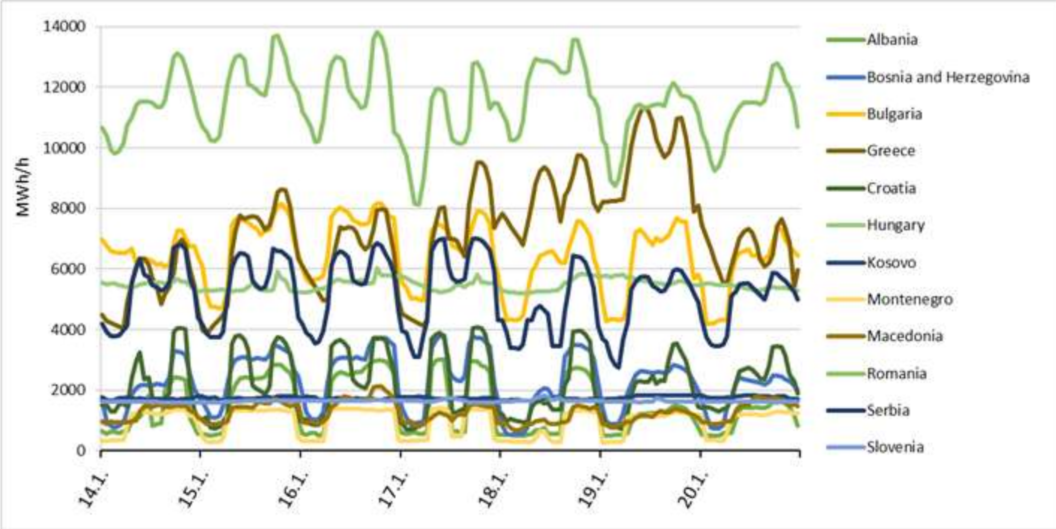



*Figure 102: Electricity generation in 3rd week of January (Alternative Case)*

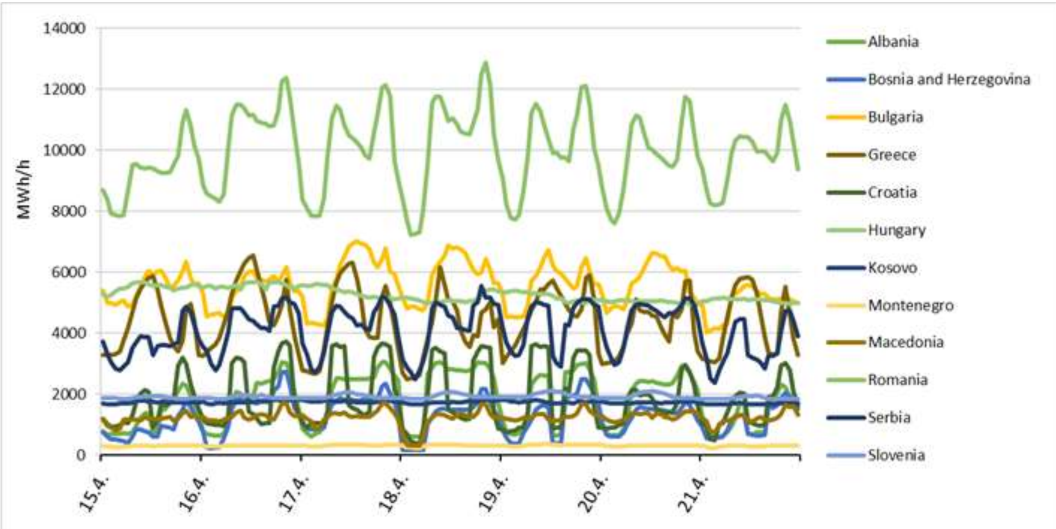



*Figure 103: Electricity generation in 3rd week of April (Alternative Case)*

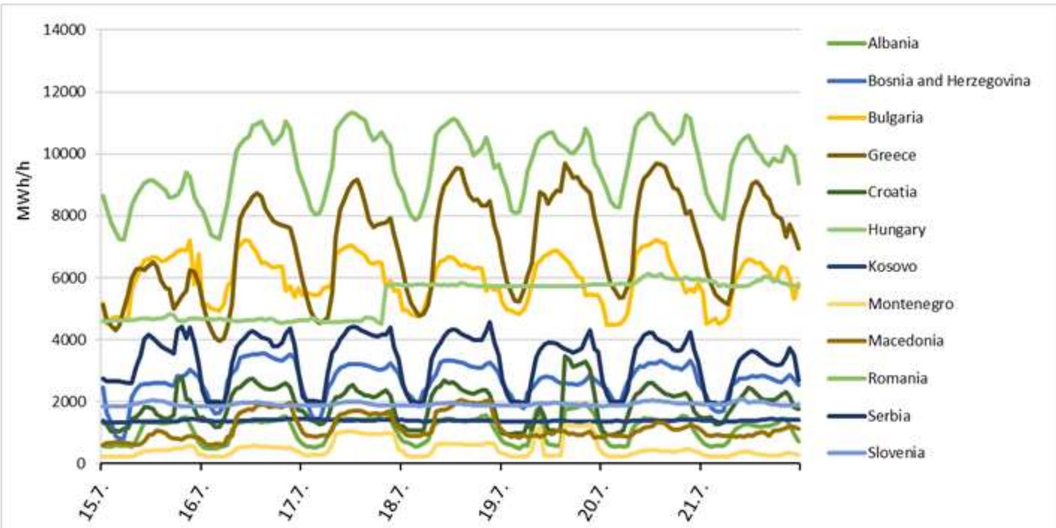



*Figure 104: Electricity generation in 3rd week of July (Alternative Case)*

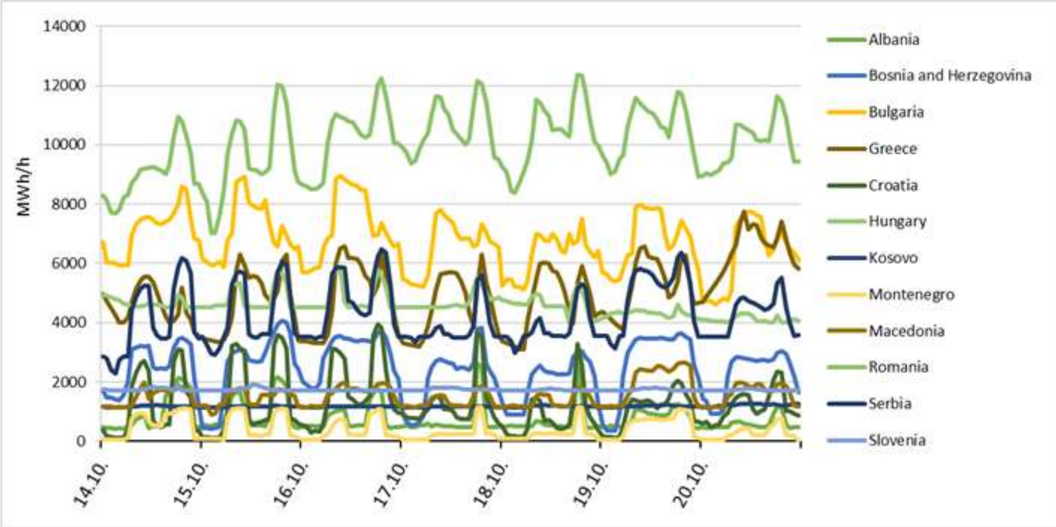



*Figure 105: Electricity generation in 3rd week of October (Alternative Case)*

Electricity balances with resulting average wholesale market price for each SEE country in Alternative Case scenario are given in Table 28. Romania and Bulgaria are the main net exporters in SEE region, while Greece is the main net importer, as in Base Case. Average market price in SEE region amounts to 56.46 €/MWh in this scenario, what is 2.15 €/MWh higher than in Base Case. Prices increase in all countries but especially in Croatia and Albania what clearly shows the effect of HVDC cables to Italy. The highest average price is in Greece (61.55 €/MWh), while the lowest is in Romania (54.84 €/MWh), as in Base Case scenario.

*Table 28: Electricity balances of SEE countries (Alternative Case)*

| Country | Load (GWh) | Generation (GWh) | Pump Load (GWh) | Customer Load (GWh) | Imports (GWh) | Exports (GWh) | Net Interchange (GWh) | Price (€/MWh) |
|---|---|---|---|---|---|---|---|---|
| **AL** | 10,791.50 | 10,792.58 | 0.00 | 10,791.50 | 8,460.59 | 8,461.66 | 1.07 | 59.41 |
| **BA** | 16,523.61 | 19,094.24 | 63.30 | 16,460.31 | 6,279.24 | 8,849.87 | 2,570.63 | 59.04 |
| **BG** | 39,669.04 | 51,607.54 | 875.00 | 38,794.03 | 8,978.87 | 20,917.37 | 11,938.51 | 55.39 |
| **GR** | 61,349.18 | 51,889.21 | 790.04 | 60,559.14 | 15,430.86 | 5,970.90 | -9,459.97 | 61.55 |
| **HR** | 22,087.13 | 15,519.19 | 88.43 | 21,998.70 | 16,695.44 | 10,127.51 | -6,567.94 | 59.41 |
| **HU** | 47,200.05 | 40,208.92 | 0.00 | 47,200.05 | 17,563.60 | 10,572.47 | -6,991.13 | 56.86 |
| **KS** | 8,221.60 | 12,057.65 | 0.00 | 8,221.60 | 3,590.79 | 7,426.83 | 3,836.04 | 59.15 |
| **ME** | 5,394.96 | 4,663.36 | 0.00 | 5,394.96 | 10,957.14 | 10,225.54 | -731.59 | 58.88 |
| **MK** | 11,382.21 | 11,044.07 | 92.22 | 11,289.98 | 9,622.96 | 9,284.82 | -338.14 | 58.81 |
| **RO** | 66,400.71 | 89,361.17 | 0.00 | 66,400.71 | 1,486.60 | 24,447.06 | 22,960.46 | 54.84 |
| **RS** | 44,472.21 | 36,950.84 | 177.59 | 44,294.62 | 23,873.17 | 16,351.80 | -7,521.37 | 58.88 |
| **SI** | 14,903.77 | 14,315.09 | 0.00 | 14,903.77 | 10,201.40 | 9,612.73 | -588.68 | 59.33 |
| **Total (GWh) / Average (€/MWh)** | **348,395.98** | **357,503.87** | **2,086.59** | **346,309.39** | **133,140.65** | **142,248.55** | **9,107.90** | **58.46** |

As already mentioned, in electricity balances total load includes customer load (demand) and pump load for pumped storage HPPs. Pump load values change in scenarios based on the operation of pump storage HPPs in pumping mode. In the following is provided example of Greek load values in Alternative Case.

Customer load in Greece is set to 60,559 GWh, while pump load for HPPs operation in pumping mode in this scenario amounts to 790 GWh and thus results in the total system load of

61,349 GWh, as presented in Table 29. Simulation results show that yearly pump load in Greece is 91 GWh lower than in Base Case scenario.

*Table 29: Greek yearly load (Alternative Case)*

| Greek load | Yearly load (GWh) |
|---|---|
| Customer load | 60,559 |
| Pump load | 790 |
| **Total load** | **61,349** |

More details are given in hourly load values for 3rd week of January, April, July and October (Figure 106 to Figure 109). When pumped storage HPP operates in pumping mode it increases the total load value, what happens in periods of low electricity prices.


*Figure 106: Greek load in 3rd week of January (Alternative Case)*

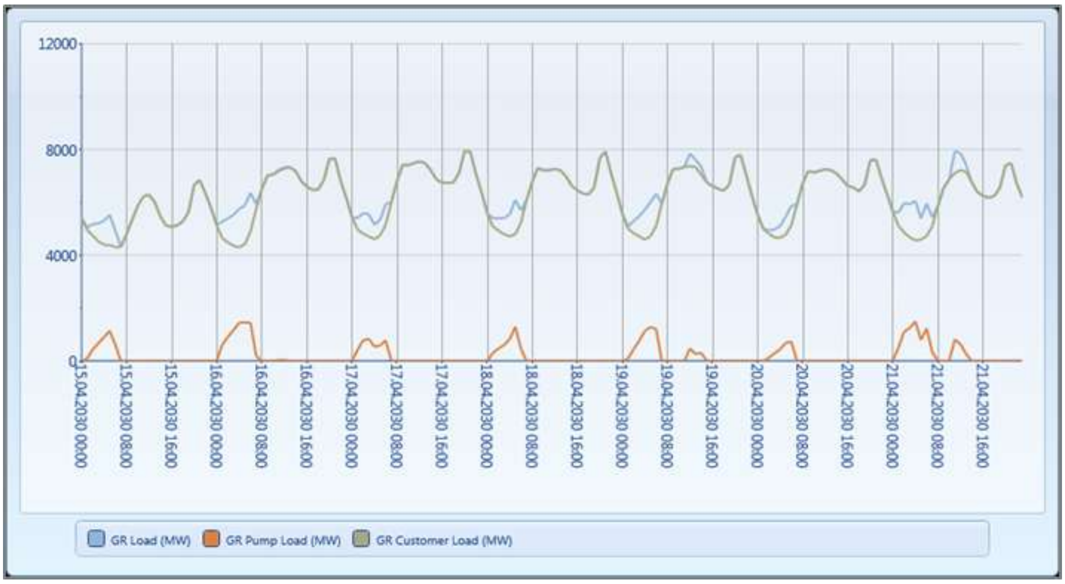



*Figure 107: Greek load in 3rd week of April (Alternative Case)*


*Figure 108: Greek load in 3rd week of July (Alternative Case)*

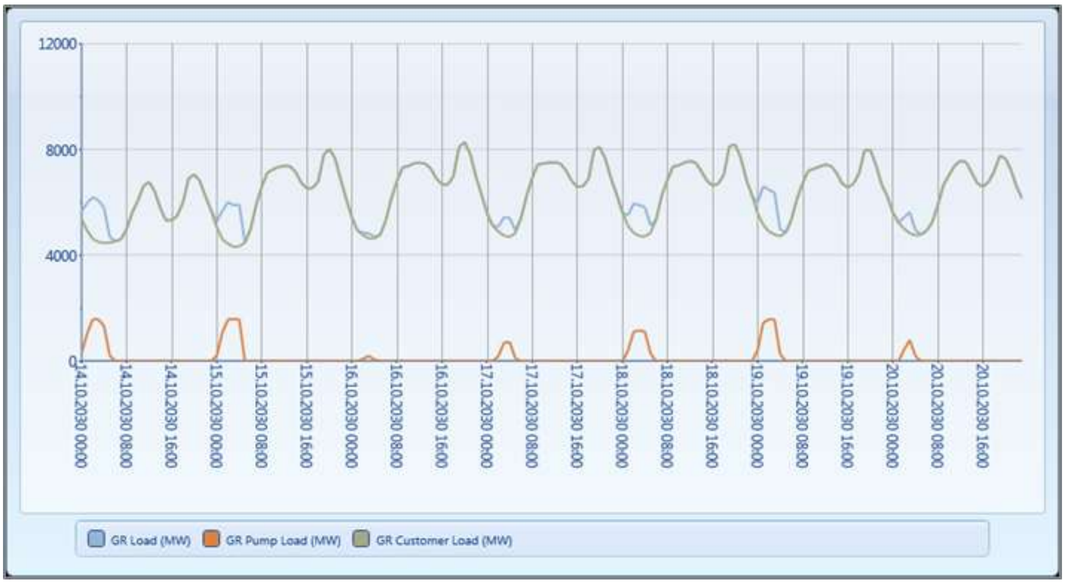



*Figure 109: Greek load in 3rd week of October (Alternative Case)*

Generation costs in SEE countries in this scenario are presented in Table 30. Average generation costs are based on variable cost including fuel and O&M cost of generating units, and on average in SEE region they amount to 13.38 €/MWh, what is slightly higher than in Base Case scenario as a result of increased TPPs generation.

As in Base Case, the lowest generation cost is in Albania (4.74 €/MWh), while the highest is in Macedonia (22.69 €/MWh). When carbon costs are included, total average generation costs in SEE region amount to 21.14 €/MWh. In terms of total average generation cost, Albania also has the lowest values, while Bosnia and Herzegovina has the highest (35.30 €/MWh) followed by Serbia (32.44 €/MWh), as in Base Case. As a reminder, Bosnia and Herzegovina and Serbia both have high share of coal-based TPPs in their generation mix.

*Table 30: Generation costs of SEE countries (Alternative Case)*

| Country | Generation (GWh) | Generation Cost (M€) | Emissions Cost (M€) | Total Generation Cost (M€) | Average Generation Cost (€/MWh) | Total Average Generation Cost (€/MWh) |
|---|---|---|---|---|---|---|
| **AL** | 10,792.58 | 51.19 | 0.00 | 51.19 | 4.74 | 4.74 |
| **BA** | 19,094.24 | 409.30 | 264.72 | 674.01 | 21.44 | 35.30 |
| **BG** | 51,607.54 | 771.38 | 428.65 | 1,200.03 | 14.95 | 23.25 |
| **GR** | 51,889.21 | 516.60 | 373.13 | 889.73 | 9.96 | 17.15 |
| **HR** | 15,519.19 | 173.83 | 64.13 | 237.96 | 11.20 | 15.33 |
| **HU** | 40,208.92 | 530.05 | 126.24 | 656.29 | 13.18 | 16.32 |
| **KS** | 12,057.65 | 98.93 | 208.20 | 307.13 | 8.20 | 25.47 |
| **ME** | 4,663.36 | 48.58 | 19.90 | 68.47 | 10.42 | 14.68 |
| **MK** | 11,044.07 | 250.64 | 102.50 | 353.14 | 22.69 | 31.98 |
| **RO** | 89,361.17 | 1,235.04 | 648.11 | 1,883.15 | 13.82 | 21.07 |
| **RS** | 36,950.84 | 714.51 | 484.14 | 1,198.64 | 19.34 | 32.44 |
| **SI** | 14,315.09 | 151.49 | 76.70 | 228.19 | 10.58 | 15.94 |
| **Total (GWh) (M€) / Average (€/MWh)** | **357,503.87** | **4,951.53** | **2,796.42** | **7,747.94** | **13.38** | **21.14** |

Alternative Case scenario includes 28 cross-border lines and 4 submarine HVDC cables (one existing GR-IT, one under construction ME-IT and two planned AL-IT and HR-IT). Yearly cross-border exchange and congestions results are given in the following tables. Generally, cross-border flows are increased in this scenario. As in Base Case, highest cross-border exchange has Serbia, i.e. 40,2225 GWh (16,352 GWh from Serbia to neighboring countries and 23,873 GWh in the opposite direction). Cross-border congestions represent the number of hours in a year flow on interconnections equals NTC. Significant congestions can be noticed, even more than in Base Case scenario. The most congestions occur on CE-SI link in the direction to Slovenia, and on the BG-GR border in the direction to Greece.

*Table 31: Cross-border exchange (Alternative Case)*

| Alternative Case | Flow (GWh) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** | **Total** |
| **AL** | - | | | 1482 | | | 318 | 249 | 581 | | | | 5832 | | | **8462** |
| **BA** | | - | | | 4473 | | | 3946 | | | 430 | | | | | **8850** |
| **BG** | | | - | 5902 | | | | | 4269 | 969 | 5717 | | | 4060 | | **20917** |
| **GR** | 472 | | 380 | - | | | | | 994 | | | | 2584 | 1541 | | **5971** |
| **HR** | | 630 | | | - | 892 | | | | | 911 | 1759 | 5936 | | | **10128** |
| **HU** | | | | | 6351 | - | | | | 445 | 3018 | | | | 758 | **10572** |
| **KS** | 2504 | | | | | | - | 1125 | 1983 | | 1815 | | | | | **7427** |
| **ME** | 1839 | 625 | | | | | 794 | - | | | 1043 | | 5924 | | | **10226** |
| **MK** | 2393 | | 98 | 5007 | | | 1260 | | - | | 527 | | | | | **9285** |
| **RO** | | | 5970 | | | 8065 | | | | - | 10412 | | | | | **24447** |
| **RS** | | 5024 | 231 | | 1775 | 1775 | 1219 | 4458 | 1796 | 72 | - | | | | | **16352** |
| **SI** | | | | | 2884 | | | | | | | - | 6292 | | 436 | **9613** |
| **IT** | 1253 | | | 1229 | 1212 | | | 1178 | | | | 946 | - | | | **5817** |
| **TR** | | | 2300 | 1811 | | | | | | | | | | - | | **4111** |
| **CE** | | | | | | 6831 | | | | | | 7497 | | | - | **14328** |
| **Total** | **8461** | **6279** | **8979** | **15431** | **16695** | **17564** | **3591** | **10957** | **9623** | **1487** | **23873** | **10201** | **26568** | **5601** | **1195** | |

*Table 32: Cross-border congestions (Alternative Case)*

| Alternative Case | Hours Congested (h) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** |
| **AL** | - | | | 5215 | | | 4 | 42 | 450 | | | | 5259 | | |
| **BA** | | - | | | 1121 | | | 104 | | | 39 | | | | |
| **BG** | | | - | 6385 | | | | | 5551 | 61 | 5535 | | | 4790 | |
| **GR** | 1466 | | 165 | - | | | | | 780 | | | | 4869 | 3722 | |
| **HR** | | 26 | | | - | 270 | | | | | 408 | 327 | 5361 | | |
| **HU** | | | | | 3412 | - | | | | 15 | 3028 | | | | 529 |
| **KS** | 651 | | | | | | - | 332 | 58 | | 224 | | | | |
| **ME** | 1138 | 0 | | | | | 238 | - | | | 29 | | 5305 | | |
| **MK** | 1209 | | 8 | 4490 | | | 84 | | - | | 592 | | | | |
| **RO** | | | 1397 | | | 3401 | | | | - | 6002 | | | | |
| **RS** | | 74 | 43 | | 1799 | 1170 | 182 | 251 | 699 | 0 | - | | | | |
| **SI** | | | | | 457 | | | | | | | - | 5292 | | 285 |
| **IT** | 847 | | | 2200 | 966 | | | 897 | | | | 623 | - | | |
| **TR** | | | 2287 | 4075 | | | | | | | | | | - | |
| **CE** | | | | | | 6115 | | | | | | 7118 | | | - |

Graphical representation of the most congested borders, i.e. interconnections with more than 65% of hours congested per year, is given in the following figure.

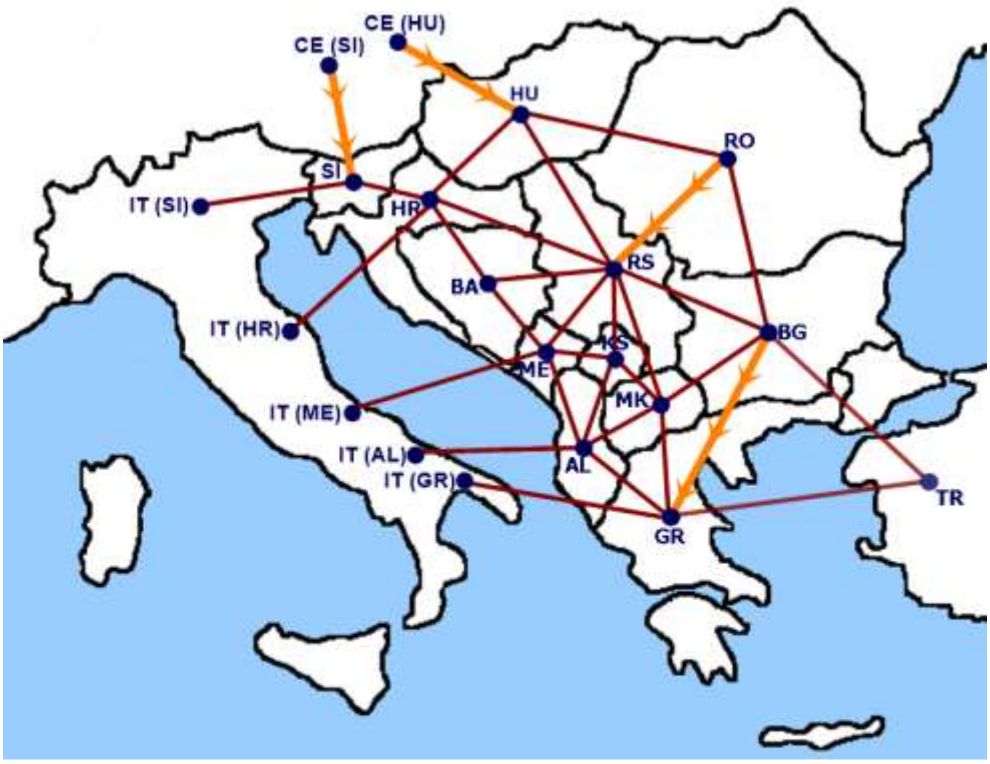



*Figure 110: Graphical representation of the most congested borders (Alternative Case)*

More details regarding HVDC cables flow are given in hourly values for 3rd week of January, April, July and October in the following figures (Figure 111 to Figure 114). As already mentioned, Alternative Case includes four HVDC cables – IT-GR, IT-ME, IT-AL and IT-HR. For all HVDC cables maximum allowed flow is set to 1,000 MW in both directions, while for IT-GR HVDC cable is set to 500 MW. As in Base Case, flow is mostly directed toward Italy, what is especially visible in July when all four HVDC cables show maximum allowed flow practically during the entire presented week, in periods of high market prices in Italy.


*Figure 111: HVDC cables flow in 3rd week of January (Alternative Case)*

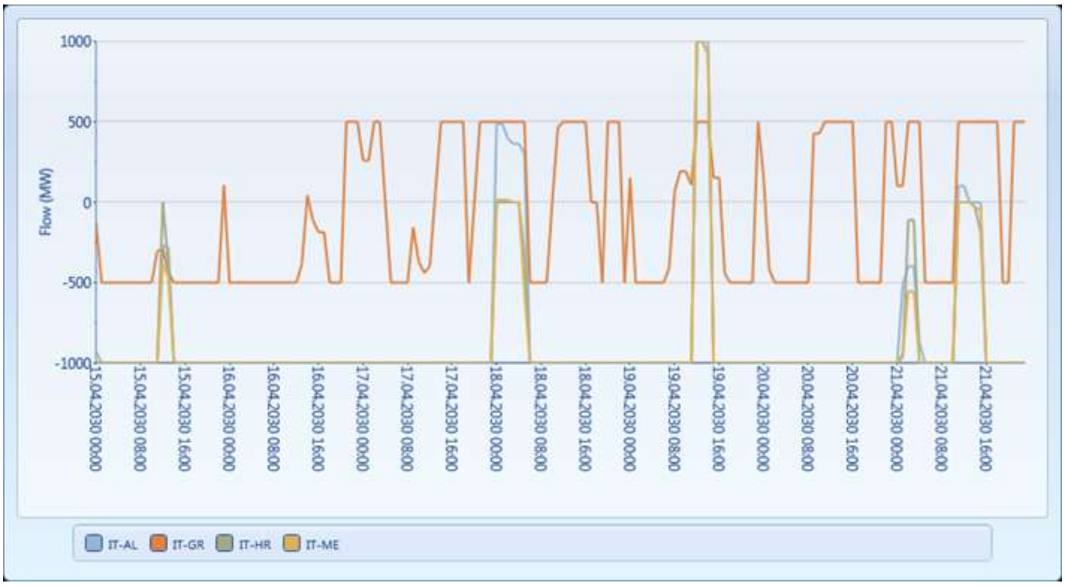



*Figure 112: HVDC cables flow in 3rd week of April (Alternative Case)*

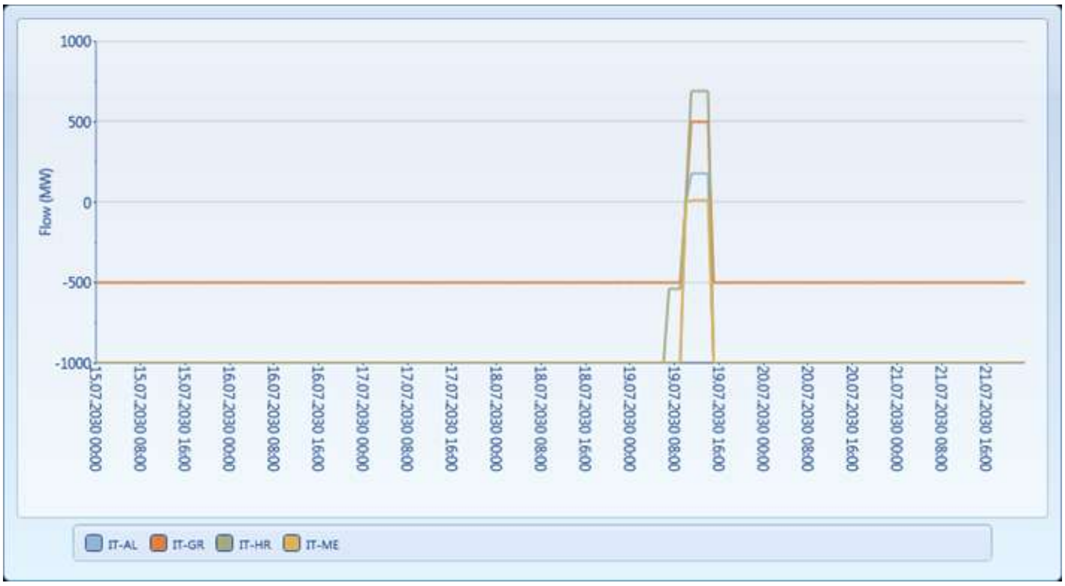



*Figure 113: HVDC cables flow in 3rd week of July (Alternative Case)*


*Figure 114: HVDC cables flow in 3rd week of October (Alternative Case)*

In the following are presented yearly values for exports, imports and net interchange for SEE countries and also for three external markets in more details.

Exports and imports values are depicted in the Figure 115, and net interchange in Figure 116. As in Base Case, Greece is the highest net importer in SEE region and Romania is the highest net exporter. From Figure 115 it can be also seen that the highest power transit is through Serbia, because of the high import and export values. Regarding external markets, the highest power transit is to Italian market and Italy mainly imports, while Central Europe mostly exports electricity to SEE region.

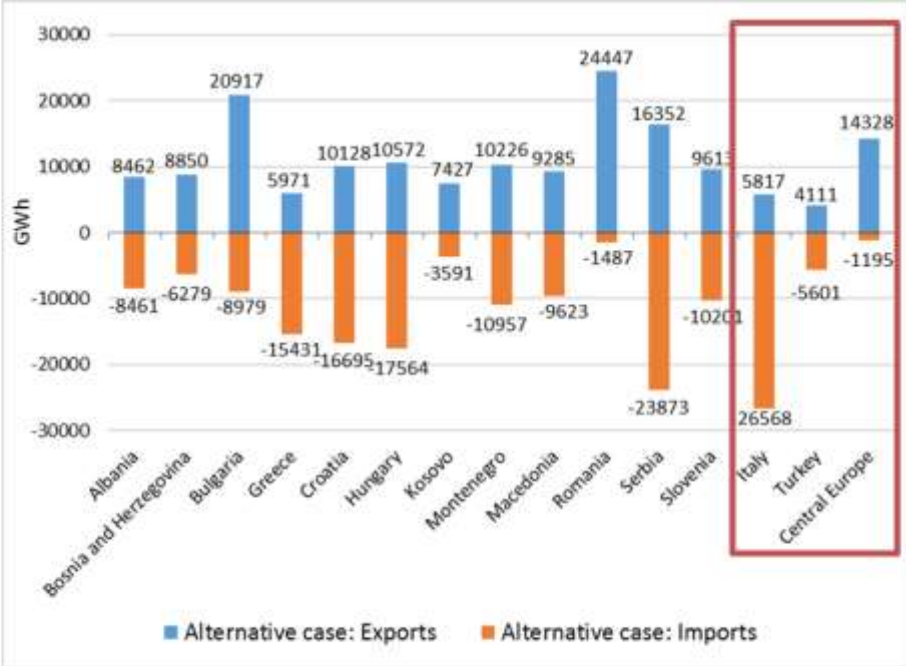



*Figure 115: Imports and exports (Alternative Case)*

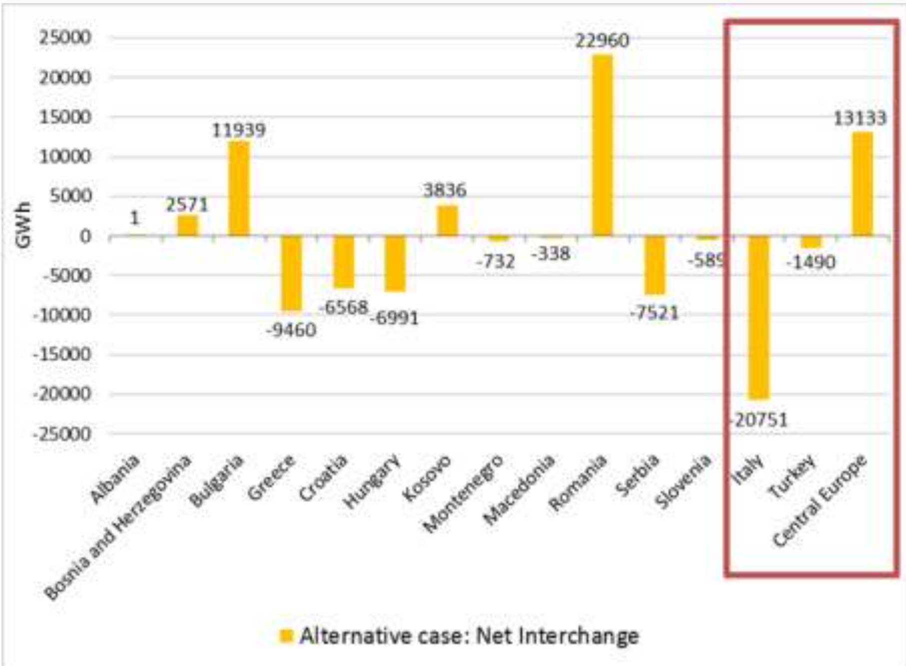



*Figure 116: Net interchange (Alternative Case)*

Weekly imports and exports simulation results for Alternative Case are given in the following figures for 3rd week of January, April, July and October.

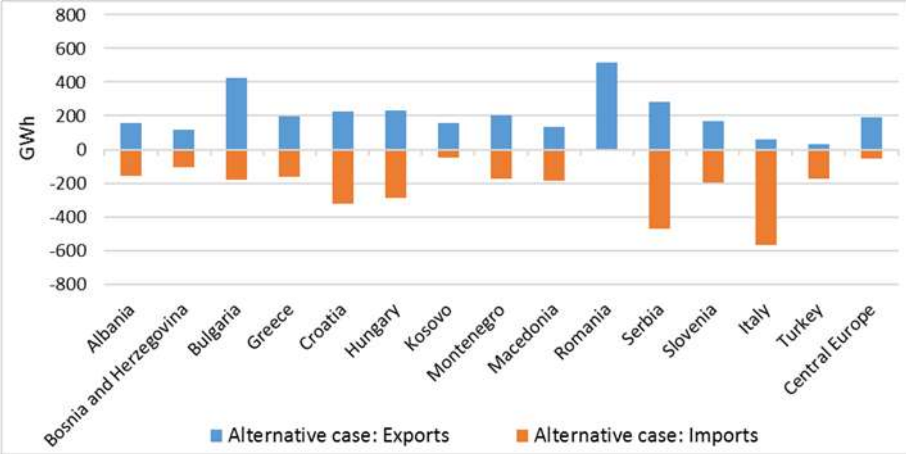



*Figure 117: Imports and exports in 3rd week of January (Alternative Case)*

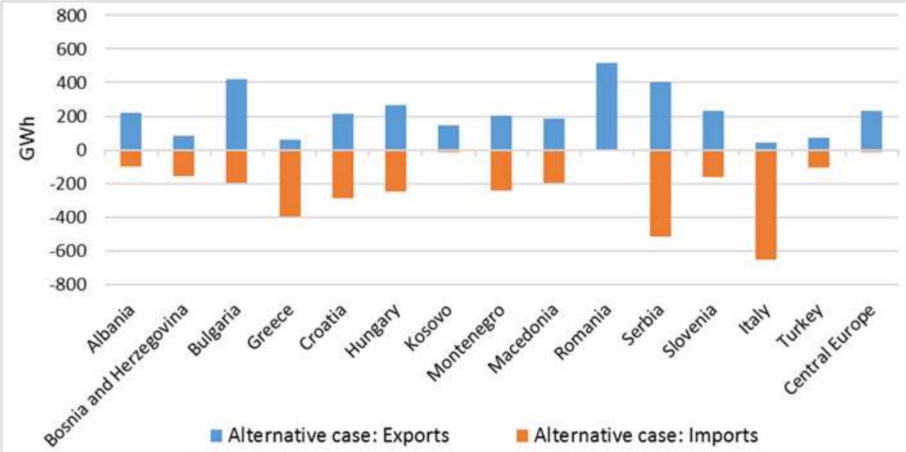



*Figure 118: Imports and exports in 3rd week of April (Alternative Case)*

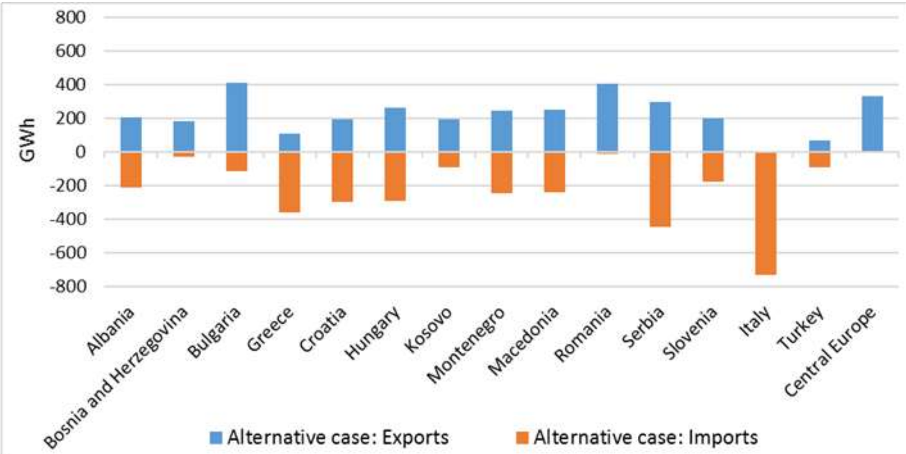



*Figure 119: Imports and exports in 3rd week of July (Alternative Case)*

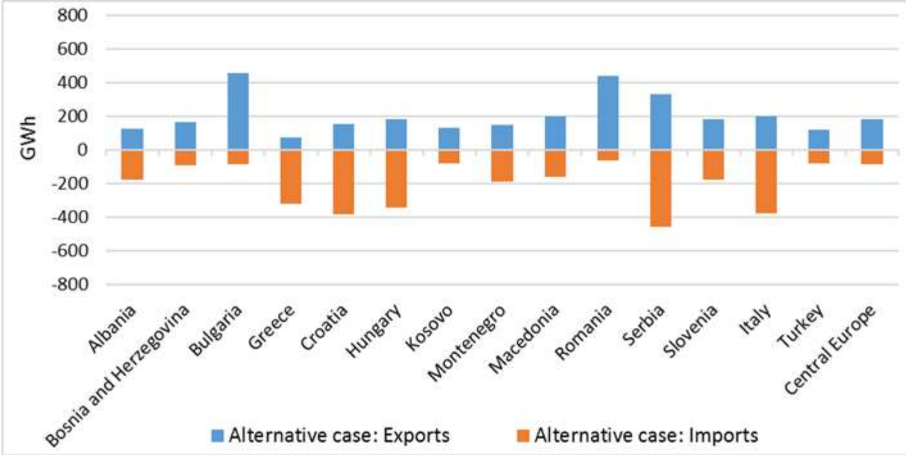



*Figure 120: Imports and exports in 3rd week of October (Alternative Case)*

In the following, more details on wholesale prices are presented for SEE countries and for external markets. Average SEE regional price is 58.46 €/MWh without taking into account external markets (Figure 121), what is 2.15 €/MWh higher than in Base Case. As in Base Case, the highest prices are in Greece (61.55 €/MWh on average) and the lowest are in Romania (54.84 €/MWh). In Base Case prices in Turkey slightly exceeded those in Italy, what is not the case in this scenario, but both of them are higher than the SEE region prices.

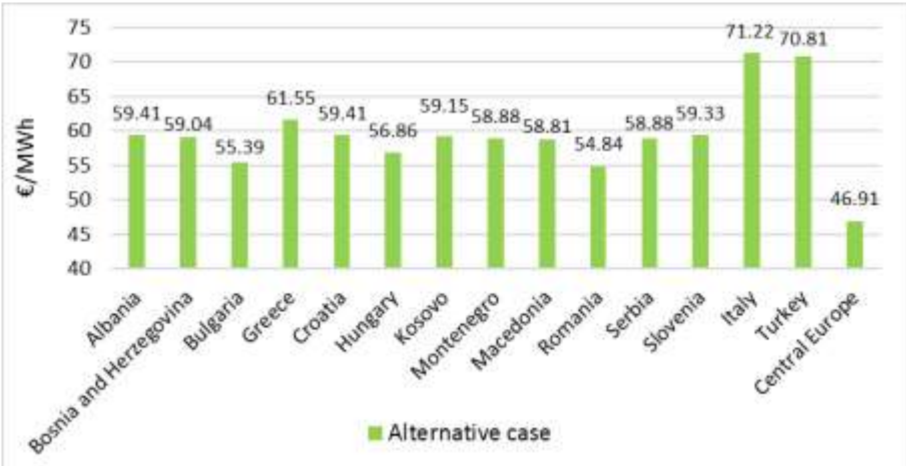



*Figure 121: Average wholesale prices (Alternative Case)*

Weekly average wholesale prices in SEE region and external markets for 3rd week of January, April, July and October are depicted in the following figures. In Base Case, Greece has the highest weekly prices in SEE region in all presented weeks, but this is not so in Alternative Case. In 3rd week of January prices in a number of countries exceed the price in Greece. Among SEE countries the highest price variations occur in April and July, while in October prices are more harmonized.

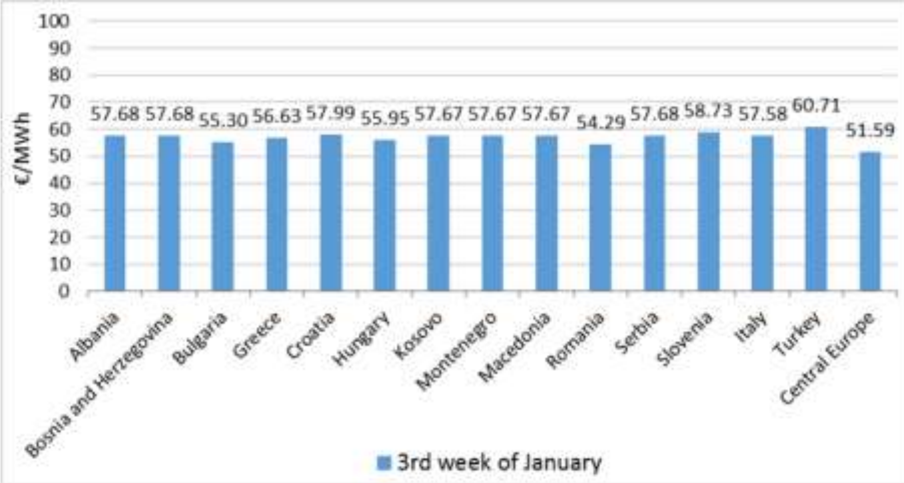



*Figure 122: Weekly average wholesale prices in 3rd week of January (Alternative Case)*

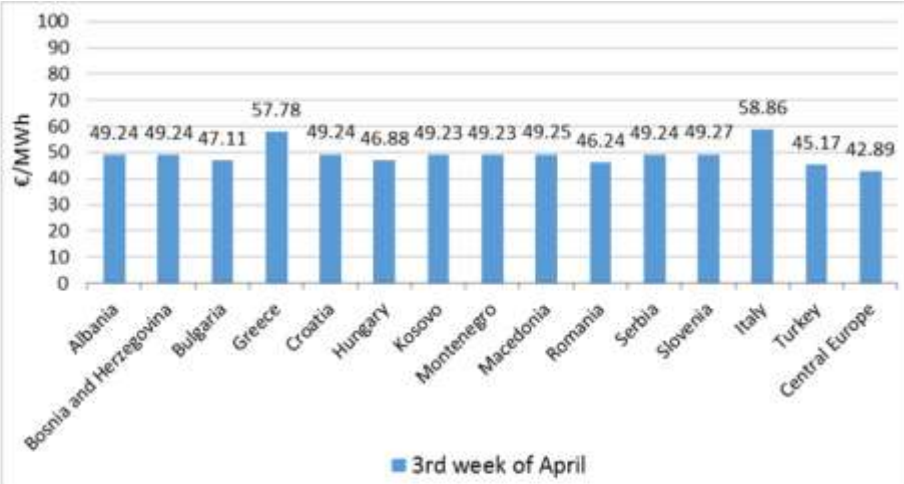



*Figure 123: Weekly average wholesale prices in 3rd week of April (Alternative Case)*

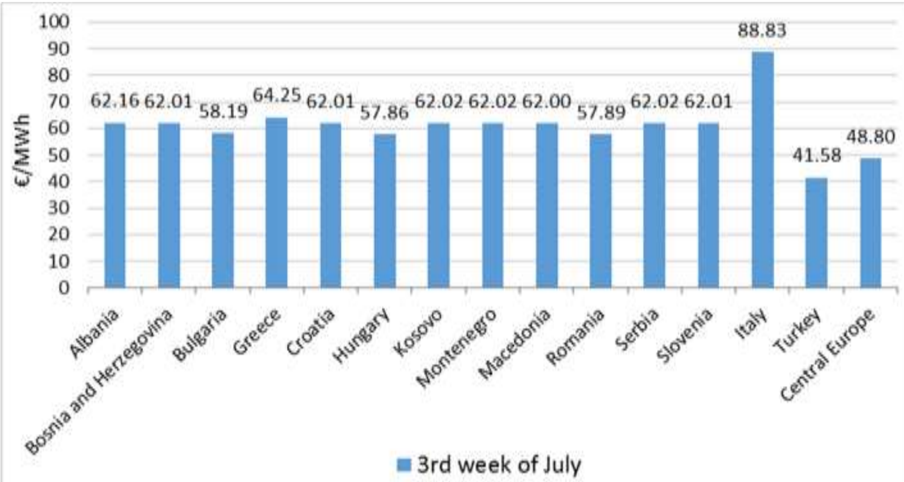



*Figure 124: Weekly average wholesale prices in 3rd week of July (Alternative Case)*

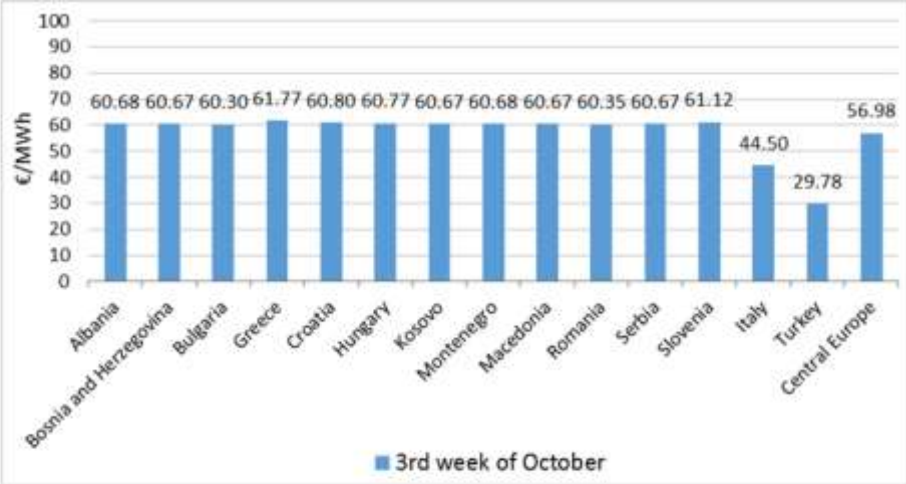



*Figure 125: Weekly average wholesale prices in 3rd week of October (Alternative Case)*

Simulation results for hourly prices in 3rd week of January, April, July and October (Figure 126 to Figure 129) are given for three selected countries – Bosnia and Herzegovina, Bulgaria and Greece.

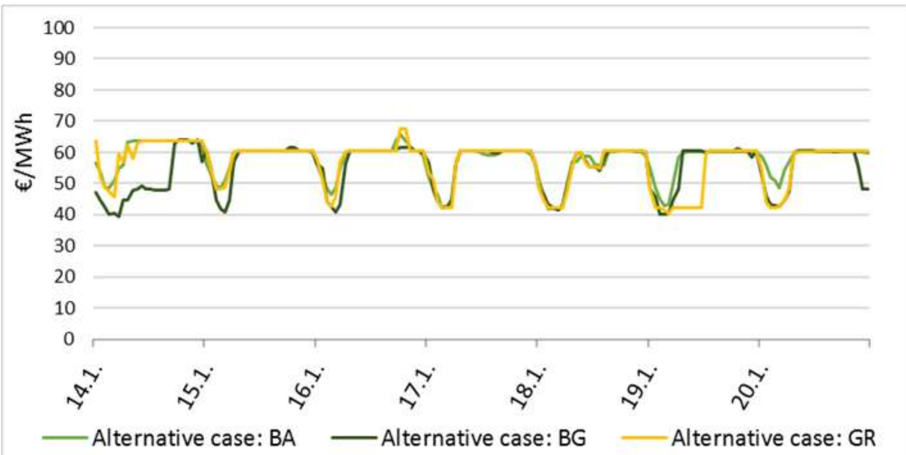



*Figure 126: Hourly wholesale prices in 3rd week of January (Alternative Case)*

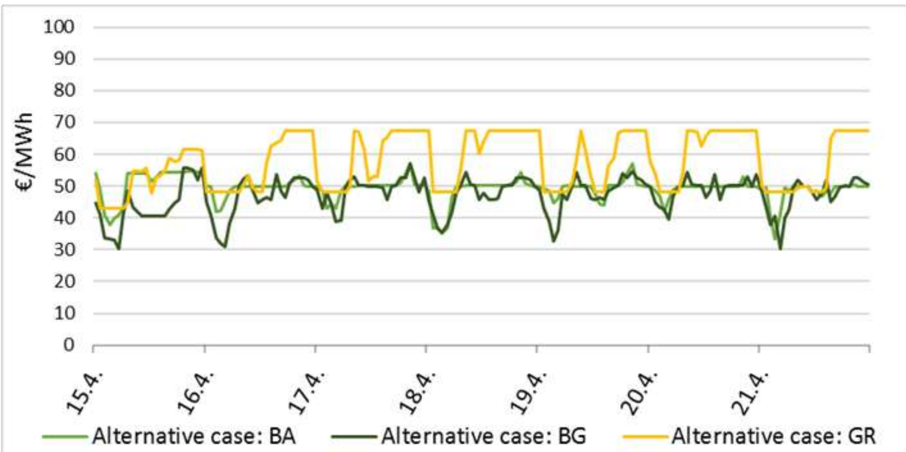



*Figure 127: Hourly wholesale prices in 3rd week of April (Alternative Case)*

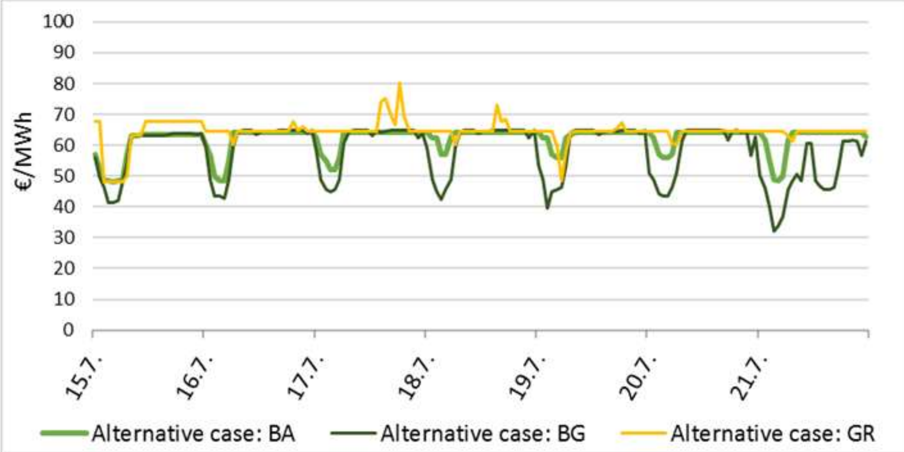


*Figure 128: Hourly wholesale prices in 3rd week of July (Alternative Case)*

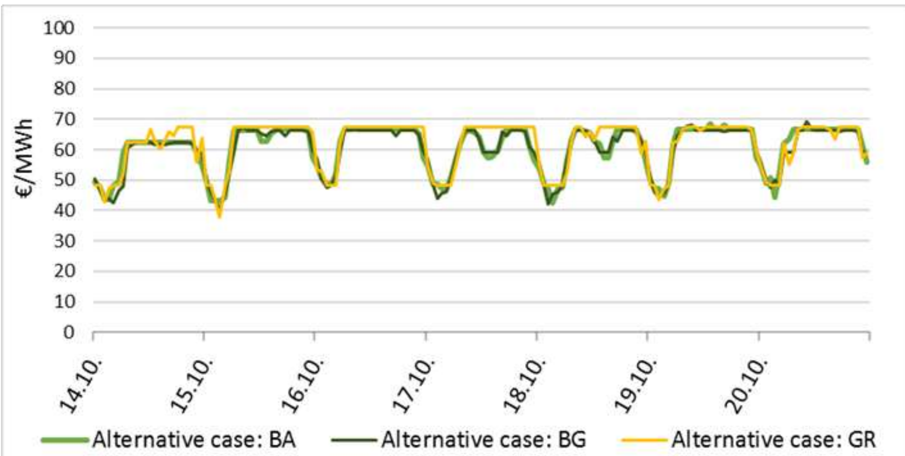


*Figure 129: Hourly wholesale prices in 3rd week of October (Alternative Case)*

## 6.2.3 Comparison of scenario results

For purposes of comparison of Base and Alternative Case scenario results, Reference Case scenario was created. Reference Case scenario only includes the existing HVDC cable Greece-Italy and thus it presents current regional interconnections with Italy. In the following Base and Alternative Case scenario are going to be compared in terms of yearly electricity generation, average wholesale prices, net interchange, total transfer and cross-border loadings.


*Figure 130: Illustration of different analyzed scenarios*

As already shown in previous chapters, electricity generation in SEE region in Base Case amounts to 351.88 TWh and in Alternative Case scenario 357.50 TWh. Simulation results for Reference Case scenario show total generation in SEE region in amount of 348.53 TWh, therefore increase in Base Case is 3.35 TWh (0.96%) while in Alternative Case it is 8.98 TWh (2.58%) compared to Reference Case. Total electricity generation in SEE region for different analyzed scenarios is depicted in Figure 131.

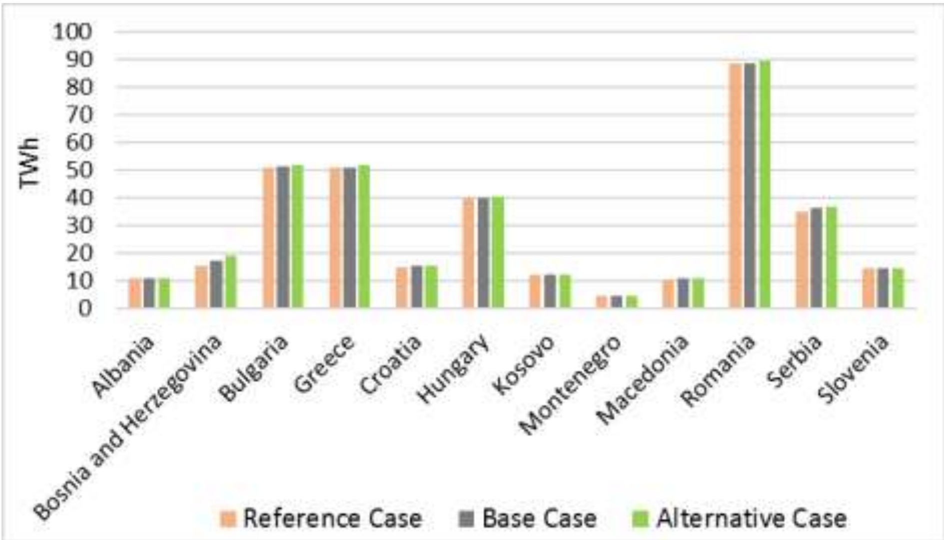



*Figure 131: Comparison of electricity generation in SEE region*

Detailed results for electricity generation together with comparison in absolute values (TWh) as well as in percentages (%) can be found in the following table. In all scenarios the highest generation is in Romania and the lowest in Montenegro, but it is important to evaluate the effect of different interconnection capacities on generation in SEE countries. The most significant change occurs in Bosnia and Herzegovina – in Base Case yearly generation is increased by 1.53 TWh (9.79%) compared to Reference Case, while in Alternative Case by 3.51 TWh (22.50%). Notable increases of electricity generation can be also observed in Bulgaria, Romania and Serbia. In several countries any significant changes cannot be noticed, for example in Albania, Hungary, Kosovo, Montenegro and Slovenia. It can be concluded that increased interconnection capacities in Base and Alternative Case mainly affect countries with high share of TPPs which increase their production. Even though Kosovo has an extremely high share of TPPs, its TPPs operate at maximum capacity almost during entire simulated year so there is no possibility of increasing electricity generation in Base and Alternative Case scenarios.

*Table 33: Comparison of electricity generation in SEE region by country*

| Yearly generation (TWh) | AL | BA | BG | GR | HR | HU | KS | ME | MK | RO | RS | SI | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 10.75 | 15.59 | 50.99 | 51.11 | 15.06 | 40.04 | 12.07 | 4.57 | 10.42 | 88.44 | 35.18 | 14.31 | **348.53** |
| **Base Case** | 10.74 | 17.11 | 51.30 | 50.99 | 15.24 | 39.93 | 12.07 | 4.57 | 10.66 | 88.85 | 36.10 | 14.31 | **351.88** |
| **Change (TWh)** | -0.01 | 1.53 | 0.32 | -0.11 | 0.18 | -0.11 | 0.00 | 0.00 | 0.24 | 0.41 | 0.92 | 0.00 | **3.35** |
| **Change (%)** | -0.12 | 9.79 | 0.62 | -0.22 | 1.18 | -0.27 | 0.00 | -0.01 | 2.33 | 0.46 | 2.61 | 0.01 | **0.96** |
| **Alternative Case** | 10.79 | 19.09 | 51.61 | 51.89 | 15.52 | 40.21 | 12.06 | 4.66 | 11.04 | 89.36 | 36.95 | 14.32 | **357.50** |
| **Change (TWh)** | 0.04 | 3.51 | 0.62 | 0.78 | 0.45 | 0.17 | -0.01 | 0.10 | 0.62 | 0.92 | 1.77 | 0.01 | **8.98** |
| **Change (%)** | 0.36 | 22.50 | 1.22 | 1.53 | 3.02 | 0.43 | -0.11 | 2.09 | 5.99 | 1.04 | 5.03 | 0.04 | **2.58** |

Comparison of average wholesale prices in different scenarios is depicted in Figure 132. In market model, market price is determined by marginal cost of generation and price on external markets. Average market price in SEE region amounts to 56.31 €/MWh in Base Case and 58.46 €/MWh in Alternative Case scenario. In Reference Case average market price in SEE region amounts to 54.71 €/MWh what makes average SEE market price in Base Case increased by 1.60 €/MWh and in Alternative Case by 3.75 €/MWh.

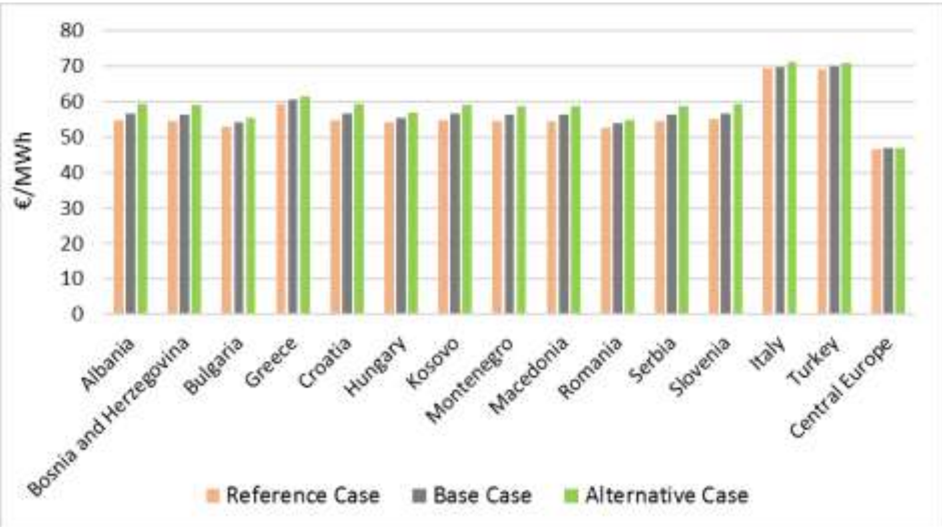



*Figure 132: Comparison of average wholesale prices*

More details on wholesale prices for SEE countries and for external markets are presented in Table 34. In all scenarios the highest average price among SEE countries is in Greece, while the lowest is in the main exporting country Romania. Average realized price on markets in Italy and Turkey is higher than SEE region average, while on market in Central Europe is significantly lower. The most significant change in Base and Alternative Case occurs in Bosnia and Herzegovina what is directly connected with increased TPPs production in these scenarios, and what causes increase of average market price by 1.87 €/MWh in Base and by 4.50 €/MWh in Alternative Case scenario. The effect of additional HVDC cables HR-IT and AL-IT in Alternative Case can be observed on increased market prices in Albania and Croatia especially in that scenario. Different scenarios have the least impact on prices in Greece and Romania.

*Table 34: Comparison of average wholesale prices by country*

| Price (€/MWh) | AL | BA | BG | GR | HR | HU | KS | ME | MK | RO | RS | SI | IT | TR | CE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 54.84 | 54.54 | 52.96 | 59.41 | 54.87 | 54.14 | 54.71 | 54.49 | 54.38 | 52.61 | 54.45 | 55.18 | 69.35 | 69.12 | 46.75 |
| **Base Case** | 56.72 | 56.41 | 54.22 | 60.47 | 56.63 | 55.36 | 56.55 | 56.34 | 56.24 | 53.79 | 56.30 | 56.70 | 69.68 | 69.91 | 46.83 |
| **Change (€/MWh)** | **1.88** | **1.87** | **1.26** | **1.06** | **1.76** | **1.22** | **1.84** | **1.85** | **1.86** | **1.18** | **1.85** | **1.52** | **0.33** | **0.78** | **0.08** |
| **Change (%)** | **3.42** | **3.43** | **2.38** | **1.78** | **3.21** | **2.26** | **3.37** | **3.39** | **3.42** | **2.24** | **3.40** | **2.75** | **0.47** | **1.13** | **0.17** |
| **Alternative Case** | 59.41 | 59.04 | 55.39 | 61.55 | 59.41 | 56.86 | 59.15 | 58.88 | 58.81 | 54.84 | 58.88 | 59.33 | 71.22 | 70.81 | 46.91 |
| **Change (€/MWh)** | **4.56** | **4.50** | **2.43** | **2.14** | **4.54** | **2.72** | **4.44** | **4.39** | **4.43** | **2.23** | **4.43** | **4.15** | **1.87** | **1.69** | **0.16** |
| **Change (%)** | **8.32** | **7.97** | **4.48** | **3.54** | **8.02** | **4.91** | **7.85** | **7.79** | **7.87** | **4.15** | **7.87** | **7.31** | **2.69** | **2.42** | **0.35** |

Figure 133 illustrates net interchange values for analyzed scenarios, while more details by country are given in Table 35. As already mentioned, net interchange is presented as the difference between export and import, hence positive net interchange value means the country is a net exporter. It is interesting to observe the high increase of Italian net interchange in Base and Alternative Case scenario as a clear effect of additional HVDC cable in respective scenarios. In Base Case scenario Italy net imports 5,214 GWh more than in Reference, while in Alternative Italy net imports 12,652 GWh more than in Reference Case scenario. On the other hand, Bosnia and Herzegovina form net importing country in Reference Case, becomes a net exporter in Base Case and even more in Alternative Case scenario. Increased net interchange value as a result of more exports in Base and Alternative Case can be also observed in Bulgaria and Romania.

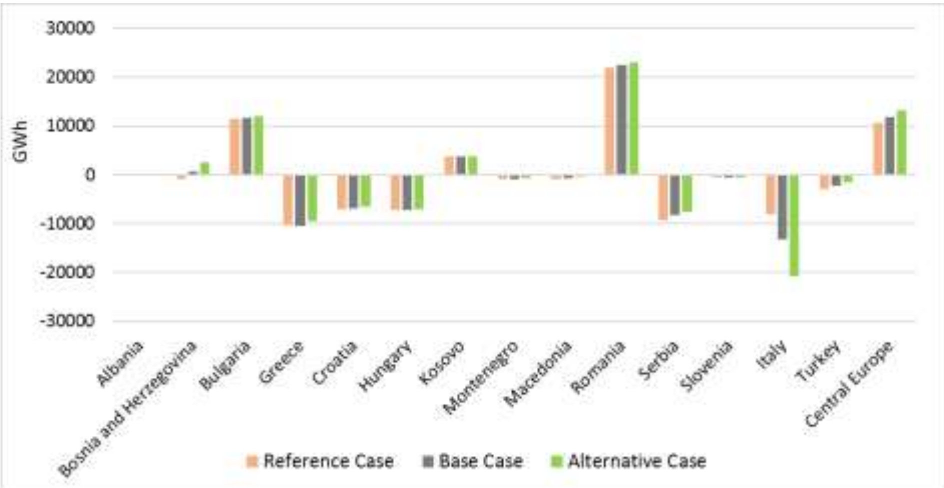



*Figure 133: Comparison of net interchange*

*Table 35: Comparison of net interchange by country*

| Net interchange (GWh) | AL | BA | BG | GR | HR | HU | KS | ME | MK | RO | RS | SI | IT | TR | CE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | -38 | -907 | 11542 | -10367 | -7014 | -7164 | 3850 | -827 | -927 | 22042 | -9240 | -594 | -8100 | -2966 | 10710 |
| **Base Case** | -50 | 622 | 11746 | -10446 | -6830 | -7273 | 3850 | -828 | -692 | 22451 | -8318 | -593 | -13314 | -2222 | 11897 |
| **Change (GWh)** | **-13** | **1529** | **204** | **-80** | **184** | **-109** | **0** | **-1** | **235** | **409** | **923** | **1** | **-5214** | **743** | **1187** |
| **Alternative Case** | 1 | 2571 | 11939 | -9460 | -6568 | -6991 | 3836 | -732 | -338 | 22960 | -7521 | -589 | -20751 | -1490 | 13133 |
| **Change (GWh)** | **39** | **3478** | **397** | **907** | **446** | **173** | **-14** | **95** | **588** | **919** | **1719** | **6** | **-12652** | **1476** | **2423** |

In some countries, for example Albania, Kosovo, Montenegro and Slovenia hardly any significant change can be noticed in terms of net interchange. Thus, to have a better understanding of exchange it is important to observe total transfer through country. Total transfer which sums up the absolute values of total yearly import and export is presented in the following figure. From Figure 134 high increase of total transfer can be seen in Albania and Croatia in Alternative Case scenario as a clear result of HVDC cables AL-IT and HR-IT. HVDC cable ME-IT also increases total transfer through Montenegro what can be observed in values for Base Case compared to Reference Case scenario.

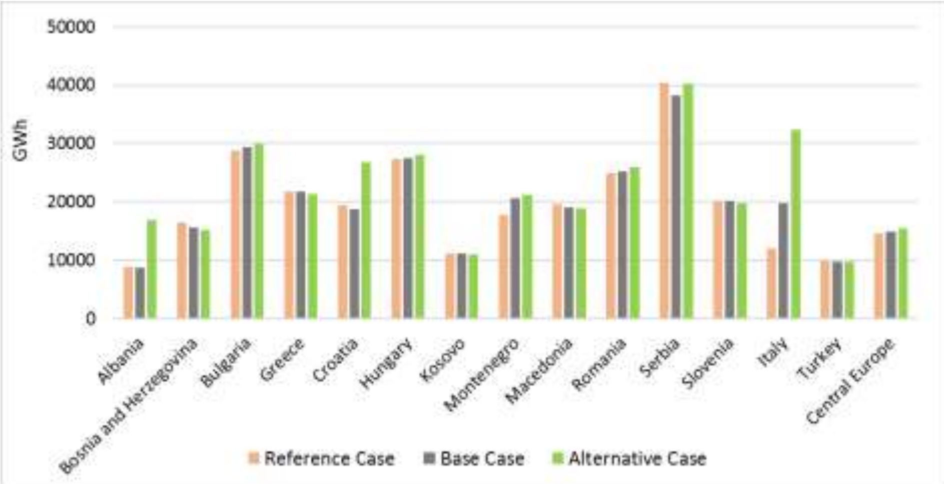



*Figure 134: Comparison of total transfer*

More details on total transfer by country are provided in Table 36. Serbia has the highest total transfer in all scenarios, but transfer decreases in Base (-2,109 GWh) and Alternative Case (-130 GWh) compared to Reference Case. Significant decrease of total transfer is also noticeable in Bosnia and Herzegovina (-866 GWh in Base and -1,332 GWh in Alternative Case compared to Reference). Increase of total transfer is expectedly visible in countries with increased interconnection capacities in respective scenarios, i.e. Albania and Croatia in Alternative Case as well as Montenegro and Italy in both Base and Alternative Case, for example Italian total transfer is increased by a substantial amount of 20,400 GWh in Alternative Case.

*Table 36: Comparison of total transfer by country*

| **Total transfer (GWh)** | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 8862 | 16461 | 28826 | 21744 | 19498 | 27414 | 11116 | 17795 | 19579 | 24893 | 40355 | 20192 | 11985 | 9843 | 14596 |
| **Base Case** | 8765 | 15595 | 29411 | 21829 | 18766 | 27500 | 11175 | 20624 | 19085 | 25144 | 38246 | 20187 | 19701 | 9798 | 14966 |
| **Change (GWh)** | **-97** | **-866** | **585** | **85** | **-732** | **85** | **58** | **2830** | **-494** | **251** | **-2109** | **-5** | **7716** | **-45** | **370** |
| **Alternative Case** | 16922 | 15129 | 29896 | 21402 | 26823 | 28136 | 11018 | 21183 | 18908 | 25934 | 40225 | 19814 | 32385 | 9712 | 15523 |
| **Change (GWh)** | **8061** | **-1332** | **1071** | **-342** | **7325** | **722** | **-99** | **3388** | **-672** | **1041** | **-130** | **-378** | **20400** | **-131** | **927** |

Italy, Turkey and Central Europe exchange with SEE region is depicted in the following figures for Reference, Base and Alternative Case scenarios (Figure 135 to Figure 137). Yearly net interchange values are presented inside the respective text boxes, while import and export values are shown next to arrows presenting exchange direction.

With increased interconnection capacities in Base and Alternative Case, SEE region becomes a stronger net exporter. In Base Case net interchange of SEE region amounts to 3,639 GWh what is 3,284 GWh more than in Reference, while in Alternative it amounts to 9,108 GWh i.e. 8,753 GWh more than in Reference Case scenario. With regard to external markets, Central Europe represents a significant net exporter to SEE region while Italy represents a net importer of energy from SEE region, and both of those markets are increasing their role in Base and Alternative Case compared to Reference Case scenario. Turkey on the other hand is a net importer of energy from SEE region in Reference Case, but in Base and Alternative Case imports from SEE region are reduced.

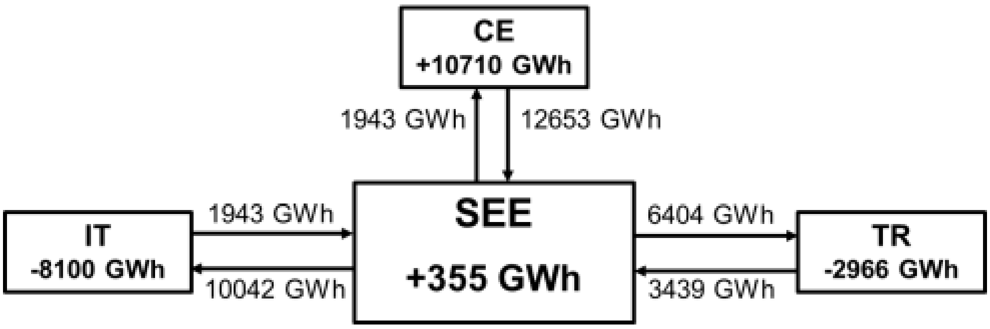



*Figure 135: Italy, Turkey, Central Europe and SEE region exchange (Reference Case)*

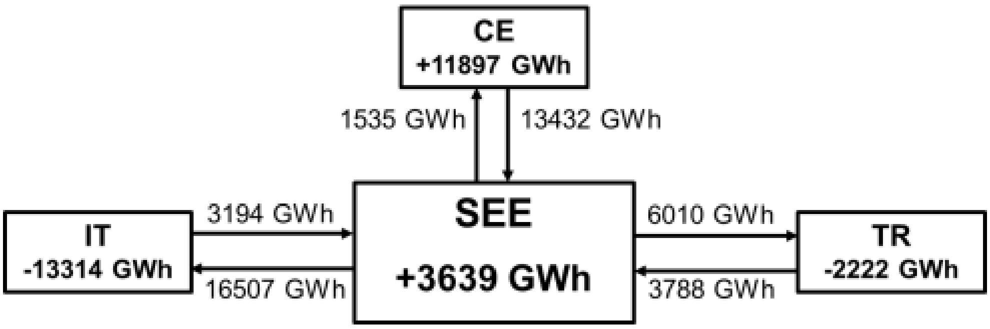



*Figure 136: Italy, Turkey, Central Europe and SEE region exchange (Base Case)*

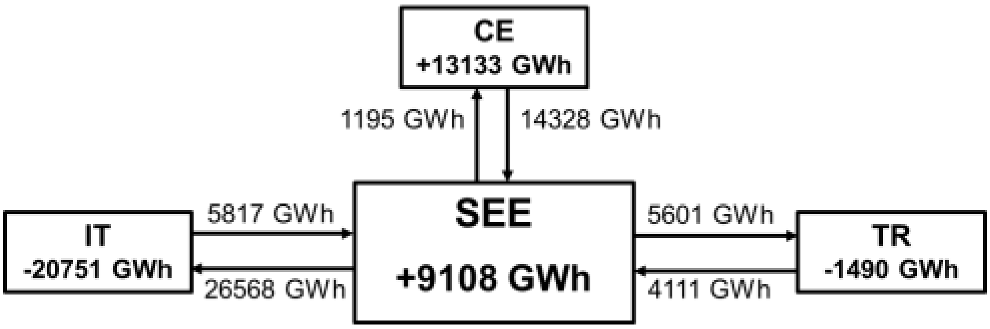



*Figure 137: Italy, Turkey, Central Europe and SEE region exchange (Alternative Case)*

Yearly average cross-border loadings are given in the following tables for Reference, Base and Alternative Case scenario. There are 29 cross-border links in Reference Case, 30 in Base Case and 32 in Alternative Case scenario. Values shown in red color refer to high flow i.e. loading above 60%, while values shown in green refer to low flow i.e. loading below 20%.

In Reference Case (Table 37), highest cross-border loading values occur on BG-GR border (85%, direction to Greece) and on RO-RS border (85%, direction to Serbia). Generally, almost all links to Greece and Italy are highly loaded as well as links from Central Europe. Romanian cross-border lines have notably low loading values in the direction to Romania (range 1-7%), while significantly higher in the opposite direction (range 46-85%).

*Table 37: Cross-border loading (Reference Case)*

| Reference Case | Loading (%) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** |
| **AL** | - | | | 75 | | | 19 | 38 | 11 | | | | | | |
| **BA** | | - | | | 37 | | | 3 | | | 31 | | | | |
| **BG** | | | - | 85 | | | | | 73 | 7 | 67 | | | 66 | |
| **GR** | 13 | | 3 | - | | | | | 6 | | | | 66 | 50 | |
| **HR** | | 10 | | | - | 15 | | | | | 19 | 27 | | | |
| **HU** | | | | | 55 | - | | | | 4 | 41 | | | | 16 |
| **KS** | 17 | | | | | | - | 23 | 41 | | 28 | | | | |
| **ME** | 20 | 45 | | | | | 28 | - | | | 4 | | | | |
| **MK** | 48 | | 6 | 80 | | | 2 | | - | | 21 | | | | |
| **RO** | | | 46 | | | 64 | | | | - | 85 | | | | |
| **RS** | | 11 | 6 | | 38 | 32 | 21 | 60 | 31 | 1 | - | | | | |
| **SI** | | | | | 18 | | | | | | | - | 81 | | 7 |
| **IT** | | | | 25 | | | | | | | | 10 | - | | |
| **TR** | | | 25 | 41 | | | | | | | | | | - | |
| **CE** | | | | | | 70 | | | | | | 75 | | | - |

In Base Case (Table 38) any significant changes in cross-border loadings cannot be observed. Although Base Case scenario includes additional HVDC cable ME-IT, links to Italy are still highly loaded meaning Italy imports even more electricity due to high prices on Italian market. With regard to other cross-border lines, situation is similar as in Base Case, for example links to Greece have high loading values especially on the BG-GR border.

*Table 38: Cross-border loading (Base Case)*

| Base Case | Loading (%) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** |
| **AL** | - | | | 75 | | | 18 | 34 | 15 | | | | | | |
| **BA** | | - | | | 26 | | | 45 | | | 5 | | | | |
| **BG** | | | - | 85 | | | | | 75 | 7 | 75 | | | 62 | |
| **GR** | 14 | | 3 | - | | | | | 9 | | | | 64 | 47 | |
| **HR** | | 15 | | | - | 15 | | | | | 12 | 23 | | | |
| **HU** | | | | | 56 | - | | | | 4 | 44 | | | | 12 |
| **KS** | 20 | | | | | | - | 34 | 32 | | 32 | | | | |
| **ME** | 20 | 3 | | | | | 16 | - | | | 12 | | 78 | | |
| **MK** | 44 | | 6 | 79 | | | 6 | | - | | 20 | | | | |
| **RO** | | | 47 | | | 65 | | | | - | 86 | | | | |
| **RS** | | 41 | 3 | | 44 | 28 | 26 | 18 | 32 | 0 | - | | | | |
| **SI** | | | | | 21 | | | | | | | - | 79 | | 6 |
| **IT** | | | | 26 | | | | 13 | | | | 11 | - | | |
| **TR** | | | 28 | 45 | | | | | | | | | | - | |
| **CE** | | | | | | 74 | | | | | | 79 | | | - |

Average cross-border loading values for Alternative Case are given in Table 39. Links to Italy have lower loading values compared to Reference and Base Case, especially HVDC cable GR-IT, as a result of additional two HVDC cables. In this scenario the highest cross-border loading value is on RO-RS border (88%, direction to Serbia), while links to Greece and Italy have somewhat lower loadings. As in previous presented scenario, links to Romania have the lowest loadings especially on the RS-RO border (1%, direction to Romania).

*Table 39: Cross-border loading (Alternative Case)*

| Alternative Case | Loading (%) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **IT** | **TR** | **CE** |
| **AL** | - | | | 68 | | | 6 | 7 | 17 | | | | 67 | | |
| **BA** | | - | | | 44 | | | 35 | | | 4 | | | | |
| **BG** | | | - | 84 | | | | | 81 | 8 | 79 | | | 58 | |
| **GR** | 22 | | 4 | - | | | | | 14 | | | | 59 | 44 | |
| **HR** | | 6 | | | - | 10 | | | | | 19 | 16 | 68 | | |
| **HU** | | | | | 60 | - | | | | 4 | 49 | | | | 9 |
| **KS** | 45 | | | | | | - | 29 | 21 | | 30 | | | | |
| **ME** | 52 | 5 | | | | | 20 | - | | | 9 | | 68 | | |
| **MK** | 46 | | 2 | 69 | | | 16 | | - | | 20 | | | | |
| **RO** | | | 47 | | | 68 | | | | - | 88 | | | | |
| **RS** | | 38 | 4 | | 41 | 25 | 20 | 40 | 34 | 1 | - | | | | |
| **SI** | | | | | 25 | | | | | | | - | 72 | | 5 |
| **IT** | 14 | | | 28 | 14 | | | 13 | | | | 11 | - | | |
| **TR** | | | 30 | 48 | | | | | | | | | | - | |
| **CE** | | | | | | 78 | | | | | | 86 | | | - |

## 6.3 Additional set of scenarios without Carbon Cost

Market simulations have been run for additional set of scenarios (Reference, Base and Alternative Case) without Carbon Cost, in order to evaluate impact of Carbon Cost i.e. the effect of $CO_2$ cost on market prices. In the following are going to be presented results for electricity balances, electricity generation, average wholesale prices and $CO_2$ emissions for Reference, Base and Alternative Case w/o Carbon Cost and compared with respective results from the main set of scenarios which include Carbon Cost.

Electricity balances of SEE countries for Reference, Base and Alternative Case w/o Carbon Cost are given from Table 40 to Table 42. Since these scenarios do not include Carbon Cost, cost of generation is lower and thus market prices, which are determined by marginal cost of generation and price on external markets, are lower. Lower market prices in SEE region have an effect on SEE region exchange making SEE region a higher net exporter of electricity, especially due to lower market prices in countries with high share of TPPs, for example Bosnia and Herzegovina.

Total SEE region net interchange in Reference Case amounted to 355 GWh, while in Reference Case w/o Carbon Cost it is 13,594 GWh higher and it amounts to 13,949 GWh. Similarly, total SEE region net interchange in Base Case w/o Carbon Cost amounts to 16,786 GWh what is 13,147 GWh higher than in main set of scenarios, while in Alternative Case w/o Carbon Cost net interchange value amounts to 22,913 GWh i.e. 13,806 GWh higher than in main set of scenarios which include Carbon Cost.

In electricity balances is presented also data on electricity generation and load. Total system load is increased in this set of scenarios w/o Carbon Cost due to higher pump load values in countries with pumped storage HPPs, especially in Reference and Base Case.

*Table 40: Electricity balances of SEE countries (Reference Case w/o Carbon Cost)*

| Country | Load (GWh) | Generation (GWh) | Pump Load (GWh) | Customer Load (GWh) | Imports (GWh) | Exports (GWh) | Net Interchange (GWh) | Price (€/MWh) |
|---|---|---|---|---|---|---|---|---|
| **AL** | 10,791.50 | 10,791.16 | 0.00 | 10,791.50 | 4,278.85 | 4,278.50 | -0.34 | 47.09 |
| **BA** | 16,593.19 | 21,637.52 | 132.88 | 16,460.31 | 5,183.39 | 10,227.72 | 5,044.33 | 46.73 |
| **BG** | 39,719.69 | 52,525.72 | 925.65 | 38,794.03 | 7,987.80 | 20,793.83 | 12,806.03 | 44.83 |
| **GR** | 61,776.16 | 52,431.97 | 1,217.02 | 60,559.14 | 15,785.85 | 6,441.66 | -9,344.19 | 53.95 |
| **HR** | 22,228.91 | 15,694.85 | 230.20 | 21,998.70 | 14,414.34 | 7,880.29 | -6,534.06 | 48.06 |
| **HU** | 47,200.05 | 40,199.83 | 0.00 | 47,200.05 | 17,252.75 | 10,252.53 | -7,000.22 | 47.64 |
| **KS** | 8,221.60 | 12,070.16 | 0.00 | 8,221.60 | 4,049.88 | 7,898.43 | 3,848.55 | 46.90 |
| **ME** | 5,394.96 | 4,584.28 | 0.00 | 5,394.96 | 7,455.15 | 6,644.48 | -810.67 | 46.75 |
| **MK** | 11,468.36 | 10,848.78 | 178.38 | 11,289.98 | 10,384.80 | 9,765.22 | -619.58 | 46.63 |
| **RO** | 66,400.71 | 90,532.99 | 0.00 | 66,400.71 | 1,050.95 | 25,183.22 | 24,132.27 | 44.28 |
| **RS** | 44,685.81 | 37,681.20 | 391.19 | 44,294.62 | 22,366.75 | 15,362.13 | -7,004.62 | 46.67 |
| **SI** | 14,903.77 | 14,335.18 | 0.00 | 14,903.77 | 10,414.45 | 9,845.86 | -568.59 | 50.90 |
| **Total (GWh) / Average (€/MWh)** | **349,384.71** | **363,333.63** | **3,075.32** | **346,309.39** | **120,624.94** | **134,573.87** | **13,948.92** | **47.54** |

*Table 41: Electricity balances of SEE countries (Base Case w/o Carbon Cost)*

| Country | Load (GWh) | Generation (GWh) | Pump Load (GWh) | Customer Load (GWh) | Imports (GWh) | Exports (GWh) | Net Interchange (GWh) | Price (€/MWh) |
|---|---|---|---|---|---|---|---|---|
| **AL** | 10,791.50 | 10,736.09 | 0.00 | 10,791.50 | 4,458.96 | 4,403.55 | -55.41 | 51.06 |
| **BA** | 16,613.66 | 22,344.64 | 153.35 | 16,460.31 | 5,258.89 | 10,989.87 | 5,730.98 | 50.71 |
| **BG** | 39,934.30 | 52,996.93 | 1,140.27 | 38,794.03 | 8,298.78 | 21,361.41 | 13,062.63 | 47.70 |
| **GR** | 61,617.27 | 52,513.52 | 1,058.14 | 60,559.14 | 15,604.22 | 6,500.47 | -9,103.75 | 55.26 |
| **HR** | 22,248.27 | 15,791.71 | 249.56 | 21,998.70 | 13,356.44 | 6,899.88 | -6,456.56 | 51.37 |
| **HU** | 47,200.05 | 40,152.76 | 0.00 | 47,200.05 | 17,602.67 | 10,555.39 | -7,047.29 | 50.31 |
| **KS** | 8,221.60 | 12,071.07 | 0.00 | 8,221.60 | 3,502.85 | 7,352.32 | 3,849.47 | 50.85 |
| **ME** | 5,394.96 | 4,550.39 | 0.00 | 5,394.96 | 11,688.42 | 10,843.85 | -844.57 | 50.63 |
| **MK** | 11,485.51 | 11,062.08 | 195.52 | 11,289.98 | 10,184.69 | 9,761.26 | -423.43 | 50.49 |
| **RO** | 66,400.71 | 91,589.86 | 0.00 | 66,400.71 | 996.91 | 26,186.05 | 25,189.14 | 46.91 |
| **RS** | 44,771.40 | 38,227.22 | 476.78 | 44,294.62 | 22,490.94 | 15,946.75 | -6,544.18 | 50.56 |
| **SI** | 14,903.77 | 14,332.95 | 0.00 | 14,903.77 | 10,245.75 | 9,674.93 | -570.82 | 52.71 |
| **Total (GWh) / Average (€/MWh)** | **349,583.01** | **366,369.22** | **3,273.62** | **346,309.39** | **123,689.51** | **140,475.72** | **16,786.21** | **50.71** |

*Table 42: Electricity balances of SEE countries (Alternative Case w/o Carbon Cost)*

| Country | Load (GWh) | Generation (GWh) | Pump Load (GWh) | Customer Load (GWh) | Imports (GWh) | Exports (GWh) | Net Interchange (GWh) | Price (€/MWh) |
|---|---|---|---|---|---|---|---|---|
| **AL** | 10,791.50 | 10,775.78 | 0.00 | 10,791.50 | 9,217.26 | 9,201.54 | -15.72 | 55.79 |
| **BA** | 16,590.65 | 22,686.25 | 130.34 | 16,460.31 | 6,290.15 | 12,385.74 | 6,095.59 | 55.43 |
| **BG** | 40,023.44 | 53,168.75 | 1,229.40 | 38,794.03 | 8,708.22 | 21,853.54 | 13,145.31 | 50.45 |
| **GR** | 61,384.74 | 54,226.30 | 825.60 | 60,559.14 | 14,315.21 | 7,156.77 | -7,158.44 | 57.30 |
| **HR** | 22,176.86 | 15,872.49 | 178.15 | 21,998.70 | 17,417.38 | 11,113.02 | -6,304.37 | 56.06 |
| **HU** | 47,200.05 | 41,134.31 | 0.00 | 47,200.05 | 17,657.59 | 11,591.85 | -6,065.74 | 53.29 |
| **KS** | 8,221.60 | 12,058.07 | 0.00 | 8,221.60 | 3,686.45 | 7,522.92 | 3,836.47 | 55.57 |
| **ME** | 5,394.96 | 4,627.50 | 0.00 | 5,394.96 | 12,151.99 | 11,384.53 | -767.46 | 55.29 |
| **MK** | 11,404.77 | 11,665.39 | 114.79 | 11,289.98 | 9,718.82 | 9,979.44 | 260.62 | 55.23 |
| **RO** | 66,400.71 | 92,728.91 | 0.00 | 66,400.71 | 865.71 | 27,193.90 | 26,328.20 | 49.36 |
| **RS** | 44,617.21 | 38,743.04 | 322.59 | 44,294.62 | 23,547.18 | 17,673.02 | -5,874.16 | 55.29 |
| **SI** | 14,903.77 | 14,336.89 | 0.00 | 14,903.77 | 10,078.85 | 9,511.98 | -566.88 | 56.43 |
| **Total (GWh) / Average (€/MWh)** | **349,110.26** | **372,023.68** | **2,800.87** | **346,309.39** | **133,654.81** | **156,568.23** | **22,913.42** | **54.63** |

Comparison of yearly electricity generation in SEE countries is presented in the following figures (Figure 138 to Figure 140) and in more details in Table 43.

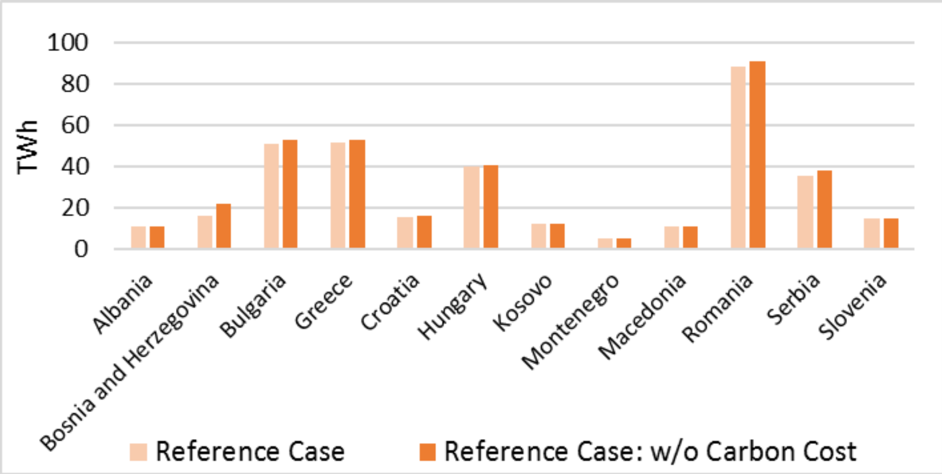



*Figure 138: Comparison of electricity generation (Reference Case w/o Carbon Cost)*

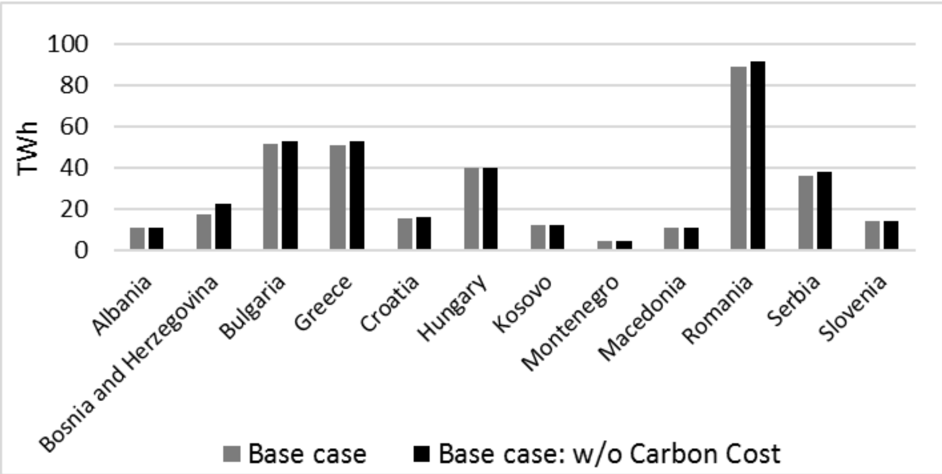



*Figure 139: Comparison of electricity generation (Base Case w/o Carbon Cost)*

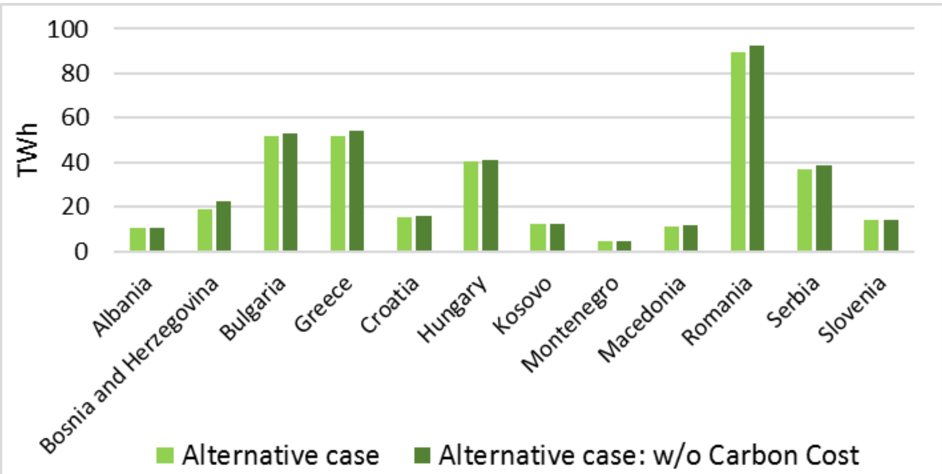



*Figure 140: Comparison of electricity generation (Alternative Case w/o Carbon Cost)*

In all scenarios w/o Carbon Cost electricity generation is expectedly increased. In Reference Case total SEE region generation is 14.81 TWh higher, 14.49 TWh in Base Case and 14.52 TWh in Alternative Case compared to main set of scenarios.

The most significant generation increase occurs in Bosnia and Herzegovina and Serbia, due to increased generation of TPPs. Electricity generation increases in almost all countries in scenarios w/o Carbon Cost, except for Albania and Kosovo which show negligible decrease in certain scenarios. TPPs in Kosovo operate at maximum capacity almost during entire simulated year in all scenarios with or w/o Carbon Cost so there is no possibility of additional increasing of electricity generation as a result of lower generation costs.

*Table 43: Comparison of electricity generation by country (w/o Carbon Cost)*

| Yearly generation (TWh) | AL | BA | BG | GR | HR | HU | KS | ME | MK | RO | RS | SI | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 10.75 | 15.59 | 50.99 | 51.11 | 15.06 | 40.04 | 12.07 | 4.57 | 10.42 | 88.44 | 35.18 | 14.31 | **348.53** |
| **Reference Case: w/o Carbon Cost** | 10.79 | 21.64 | 52.53 | 52.43 | 15.69 | 40.20 | 12.07 | 4.58 | 10.85 | 90.53 | 37.68 | 14.34 | **363.33** |
| **Change (TWh)** | **0.04** | **6.05** | **1.54** | **1.32** | **0.63** | **0.16** | **0.00** | **0.02** | **0.43** | **2.09** | **2.50** | **0.03** | **14.81** |
| **Change (%)** | **0.35** | **38.81** | **3.02** | **2.59** | **4.18** | **0.41** | **-0.01** | **0.36** | **4.11** | **2.36** | **7.11** | **0.18** | **4.25** |
| **Base Case** | 10.74 | 17.11 | 51.30 | 50.99 | 15.24 | 39.93 | 12.07 | 4.57 | 10.66 | 88.85 | 36.10 | 14.31 | **351.88** |
| **Base Case: w/o Carbon Cost** | 10.74 | 22.34 | 53.00 | 52.51 | 15.79 | 40.15 | 12.07 | 4.55 | 11.06 | 91.59 | 38.23 | 14.33 | **366.37** |
| **Change (TWh)** | **-0.01** | **5.23** | **1.70** | **1.52** | **0.55** | **0.23** | **0.00** | **-0.02** | **0.40** | **2.74** | **2.13** | **0.02** | **14.49** |
| **Change (%)** | **-0.05** | **30.57** | **3.31** | **2.98** | **3.60** | **0.57** | **0.00** | **-0.37** | **3.75** | **3.08** | **5.90** | **0.15** | **4.12** |
| **Alternative Case** | 10.79 | 19.09 | 51.61 | 51.89 | 15.52 | 40.21 | 12.06 | 4.66 | 11.04 | 89.36 | 36.95 | 14.32 | **357.50** |
| **Alternative Case: w/o Carbon Cost** | 10.78 | 22.69 | 53.17 | 54.23 | 15.87 | 41.13 | 12.06 | 4.63 | 11.67 | 92.73 | 38.74 | 14.34 | **372.02** |
| **Change (TWh)** | **-0.02** | **3.59** | **1.56** | **2.34** | **0.35** | **0.93** | **0.00** | **-0.04** | **0.62** | **3.37** | **1.79** | **0.02** | **14.52** |
| **Change (%)** | **-0.16** | **18.81** | **3.03** | **4.50** | **2.28** | **2.30** | **0.00** | **-0.77** | **5.63** | **3.77** | **4.85** | **0.15** | **4.06** |

Average wholesale prices comparison is presented for Reference, Base and Alternative Case scenarios in the following figures, while more details with differences in absolute values (€/MWh) as well as in percentages (%) can be found in Table 44.

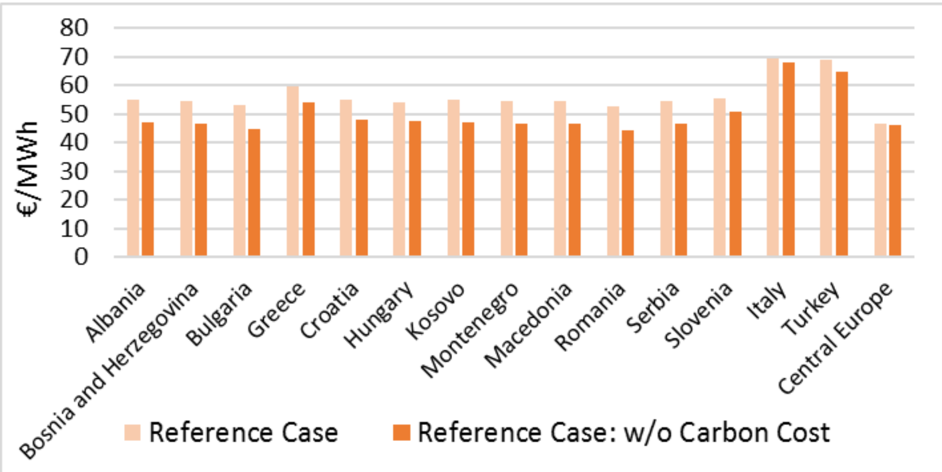



*Figure 141: Comparison of average wholesale prices (Reference Case w/o Carbon Cost)*

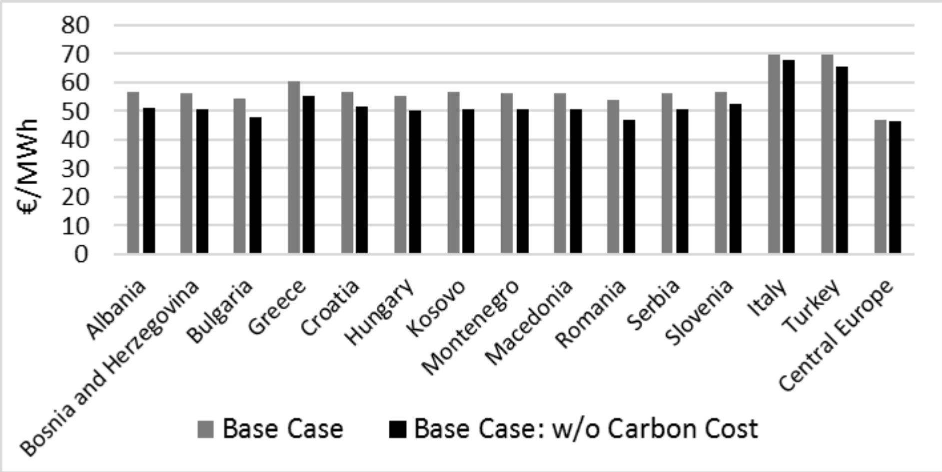



*Figure 142: Comparison of average wholesale prices (Base Case w/o Carbon Cost)*

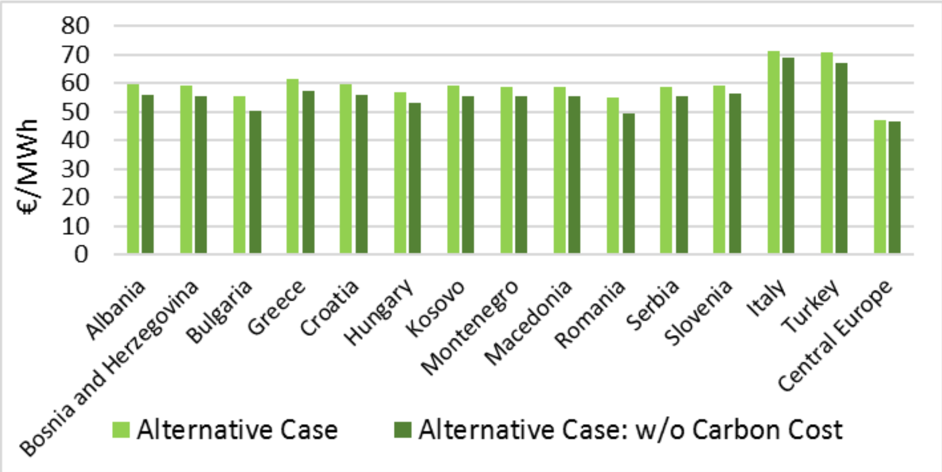



*Figure 143: Comparison of average wholesale prices (Alternative Case w/o Carbon Cost)*

Among SEE countries Bulgaria, Romania and Serbia show the most significant decrease of average market price in scenarios w/o Carbon Cost, for example in Reference Case w/o Carbon Cost market prices in Romania are decreased by 8.33 €/MWh (almost 16%). In SEE region the smallest market price change in scenarios w/o Carbon Cost can be observed in Slovenia.

*Table 44: Comparison of average wholesale prices by country (w/o Carbon Cost)*

| Price (€/MWh) | AL | BA | BG | GR | HR | HU | KS | ME | MK | RO | RS | SI | IT | TR | CE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 54.84 | 54.54 | 52.96 | 59.41 | 54.87 | 54.14 | 54.71 | 54.49 | 54.38 | 52.61 | 54.45 | 55.18 | 69.35 | 69.12 | 46.75 |
| **Reference Case: w/o Carbon Cost** | 47.09 | 46.73 | 44.83 | 53.95 | 48.06 | 47.64 | 46.90 | 46.75 | 46.63 | 44.28 | 46.67 | 50.90 | 67.77 | 64.64 | 46.22 |
| **Change (€/MWh)** | **-7.75** | **-7.82** | **-8.13** | **-5.46** | **-6.81** | **-6.49** | **-7.81** | **-7.74** | **-7.75** | **-8.33** | **-7.78** | **-4.29** | **-1.58** | **-4.49** | **-0.52** |
| **Change (%)** | **-14.13** | **-14.33** | **-15.35** | **-9.18** | **-12.41** | **-12.00** | **-14.28** | **-14.20** | **-14.24** | **-15.84** | **-14.29** | **-7.77** | **-2.28** | **-6.49** | **-1.12** |
| **Base Case** | 56.72 | 56.41 | 54.22 | 60.47 | 56.63 | 55.36 | 56.55 | 56.34 | 56.24 | 53.79 | 56.30 | 56.70 | 69.68 | 69.91 | 46.83 |
| **Base Case: w/o Carbon Cost** | 51.06 | 50.71 | 47.70 | 55.26 | 51.37 | 50.31 | 50.85 | 50.63 | 50.49 | 46.91 | 50.56 | 52.71 | 67.78 | 65.75 | 46.42 |
| **Change (€/MWh)** | **-5.67** | **-5.71** | **-6.52** | **-5.20** | **-5.26** | **-5.04** | **-5.71** | **-5.71** | **-5.75** | **-6.88** | **-5.73** | **-3.99** | **-1.90** | **-4.15** | **-0.40** |
| **Change (%)** | **-9.99** | **-10.12** | **-12.03** | **-8.60** | **-9.29** | **-9.11** | **-10.09** | **-10.13** | **-10.23** | **-12.78** | **-10.18** | **-7.05** | **-2.73** | **-5.94** | **-0.86** |
| **Alternative Case** | 59.41 | 59.04 | 55.39 | 61.55 | 59.41 | 56.86 | 59.15 | 58.88 | 58.81 | 54.84 | 58.88 | 59.33 | 71.22 | 70.81 | 46.91 |
| **Alternative Case: w/o Carbon Cost** | 55.79 | 55.43 | 50.45 | 57.30 | 56.06 | 53.29 | 55.57 | 55.29 | 55.23 | 49.36 | 55.29 | 56.43 | 68.83 | 67.30 | 46.64 |
| **Change (€/MWh)** | **-3.62** | **-3.61** | **-4.94** | **-4.25** | **-3.35** | **-3.56** | **-3.58** | **-3.58** | **-3.58** | **-5.48** | **-3.59** | **-2.89** | **-2.40** | **-3.51** | **-0.27** |
| **Change (%)** | **-6.09** | **-6.11** | **-8.92** | **-6.90** | **-5.63** | **-6.27** | **-6.05** | **-6.08** | **-6.08** | **-9.99** | **-6.09** | **-4.88** | **-3.36** | **-4.96** | **-0.58** |

As for the total SEE region, average wholesale price in analyzed scenarios with and w/o Carbon Cost and their comparison is given in Table 45. In Reference Case can be observed the highest price difference which amounts to 7.18 €/MWh, while price difference is lower in Base and Alternative Case – 5.60 €/MWh and 3.84 €/MWh respectively. As a reminder, $CO_2$ allowances price is set to 17 €/t in this market study.

*Table 45: Comparison of average wholesale prices in SEE region (w/o Carbon Cost)*

| Price (€/MWh) | with Carbon Cost | w/o Carbon Cost | Price difference |
|---|---|---|---|
| **Reference Case** | 54.71 | 47.54 | **7.18** |
| **Base Case** | 56.31 | 50.71 | **5.60** |
| **Alternative Case** | 58.46 | 54.63 | **3.84** |

It can be concluded that the impact of Carbon Cost, i.e. the effect of $CO_2$ allowances price on market price, decreases with increasing interconnection capacities in Base and Alternative Case.

In scenarios without Carbon Cost electricity generation in SEE region increases due to increased TPPs production, thus it is important to observe also the amount of $CO_2$ emissions which is increased in scenarios w/o Carbon Cost.

Amount of $CO_2$ emissions in Reference, Base and Alternative Case with and w/o Carbon Cost is illustrated in the following figures and compared by country in As in the case of electricity generation, in all scenarios w/o Carbon Cost amounts of $CO_2$ emissions are increased. In Reference Case total $CO_2$ emissions in SEE region are increased by 14.56 Mt, in Base Case by 13.04 Mt and in Alternative Case by 11.48 Mt compared to main set of scenarios. Changes in $CO_2$ emissions among SEE countries are consistent with electricity generation results, so the most significant $CO_2$ emissions increase occurs in Bosnia and Herzegovina and Serbia.

Table 46.

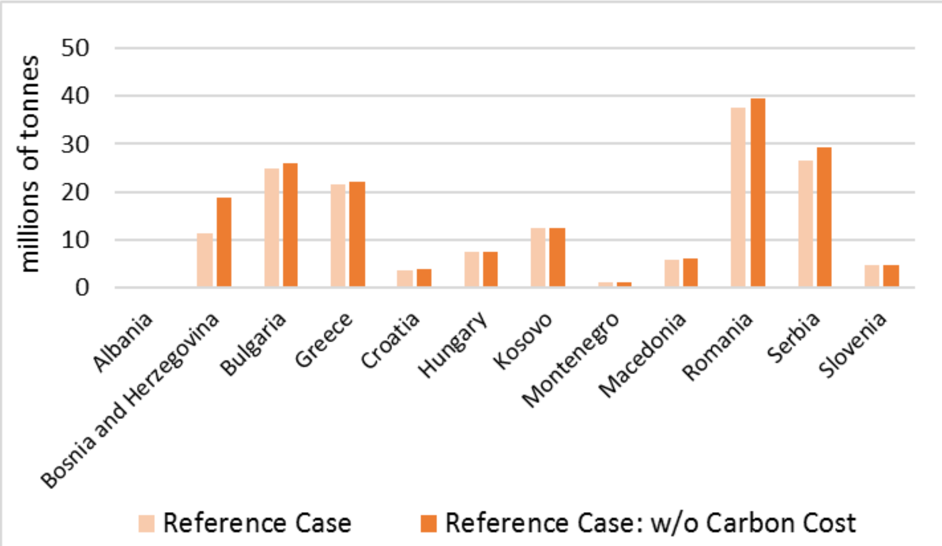



*Figure 144: Comparison of amount of $CO_2$ emissions (Reference Case w/o Carbon Cost)*

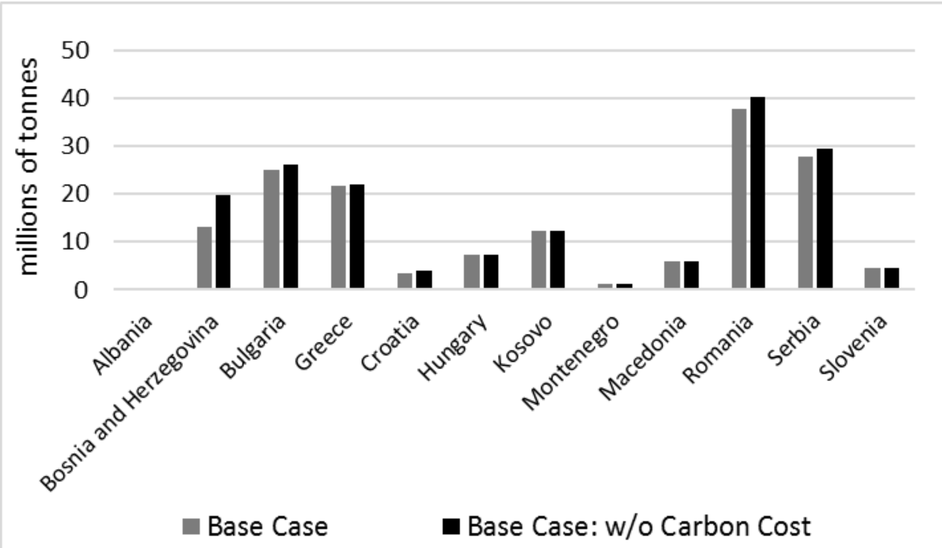



*Figure 145: Comparison of amount of $CO_2$ emissions (Base Case w/o Carbon Cost)*

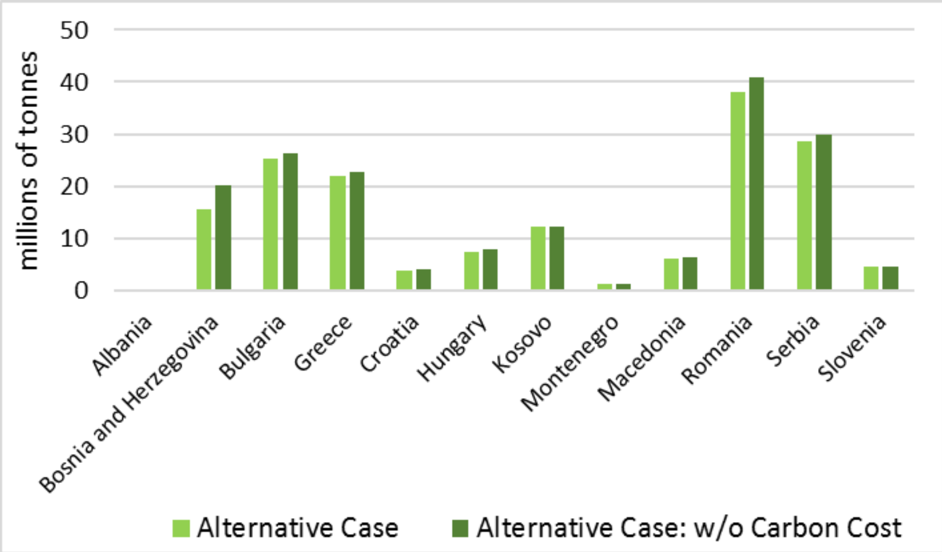



*Figure 146: Comparison of amount of $CO_2$ emissions (Alternative Case w/o Carbon Cost)*

As in the case of electricity generation, in all scenarios w/o Carbon Cost amounts of $CO_2$ emissions are increased. In Reference Case total $CO_2$ emissions in SEE region are increased by 14.56 Mt, in Base Case by 13.04 Mt and in Alternative Case by 11.48 Mt compared to main set of scenarios. Changes in $CO_2$ emissions among SEE countries are consistent with electricity generation results, so the most significant $CO_2$ emissions increase occurs in Bosnia and Herzegovina and Serbia.

*Table 46: Comparison of amount of $CO_2$ emissions by country (w/o Carbon Cost)*

| **$CO_2$ Emissions (millions of tonnes)** | **AL** | **BA** | **BG** | **GR** | **HR** | **HU** | **KS** | **ME** | **MK** | **RO** | **RS** | **SI** | **TOTAL** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Reference Case** | 0.00 | 11.17 | 24.90 | 21.62 | 3.40 | 7.35 | 12.26 | 1.14 | 5.71 | 37.49 | 26.64 | 4.51 | **156.18** |
| **Reference Case: w/o Carbon Cost** | 0.00 | 18.76 | 26.01 | 21.98 | 3.89 | 7.41 | 12.26 | 1.15 | 5.98 | 39.62 | 29.14 | 4.52 | **170.75** |
| **Change (Mt)** | **0.00** | **7.59** | **1.11** | **0.37** | **0.50** | **0.06** | **0.00** | **0.01** | **0.27** | **2.13** | **2.50** | **0.02** | **14.56** |
| **Change (%)** | **0.00** | **67.97** | **4.46** | **1.70** | **14.66** | **0.83** | **0.00** | **1.19** | **4.77** | **5.68** | **9.38** | **0.34** | **9.32** |
| **Base Case** | 0.00 | 13.13 | 25.09 | 21.59 | 3.56 | 7.32 | 12.26 | 1.13 | 5.86 | 37.79 | 27.73 | 4.51 | **159.98** |
| **Base Case: w/o Carbon Cost** | 0.00 | 19.65 | 26.23 | 22.05 | 3.96 | 7.40 | 12.26 | 1.14 | 6.07 | 40.24 | 29.47 | 4.52 | **173.02** |
| **Change (Mt)** | **0.00** | **6.52** | **1.14** | **0.46** | **0.41** | **0.08** | **0.00** | **0.01** | **0.21** | **2.46** | **1.74** | **0.01** | **13.04** |
| **Change (%)** | **0.00** | **49.69** | **4.56** | **2.12** | **11.48** | **1.14** | **0.00** | **0.74** | **3.57** | **6.50** | **6.28** | **0.30** | **8.15** |
| **Alternative Case** | 0.00 | 15.57 | 25.21 | 21.95 | 3.77 | 7.43 | 12.25 | 1.17 | 6.03 | 38.12 | 28.48 | 4.51 | **164.50** |
| **Alternative Case: w/o Carbon Cost** | 0.00 | 20.10 | 26.37 | 22.75 | 4.04 | 7.76 | 12.25 | 1.17 | 6.29 | 40.89 | 29.82 | 4.53 | **175.97** |
| **Change (Mt)** | **0.00** | **4.53** | **1.15** | **0.80** | **0.27** | **0.34** | **0.00** | **0.00** | **0.26** | **2.77** | **1.35** | **0.01** | **11.48** |
| **Change (%)** | **0.00** | **29.10** | **4.56** | **3.64** | **7.09** | **4.53** | **0.01** | **0.23** | **4.37** | **7.26** | **4.73** | **0.30** | **6.98** |

# 7 NETWORK ANALYSES RESULTS

## 7.1 Prerequisites and assumptions

PSS/E RTSM (Regional Transmission System Model) which was created by SECI Project Group on the Regional Transmission System Planning, sponsored by USAID, has been used as starting model for the analyses. With a participation of all power system utilities and planners from South East Europe, the Project Group finalized the PSS/E Regional Transmission System Model for 2030 used as starting model. The Regional Transmission System Model also comprises models of Greece, Turkey, Slovenia, Burstyn Island (Ukraine), Italy, Hungary and Austria, with aim to have adequate network representation for all types of network analyses. High voltage transmission network of 750 kV, 400 kV, 220 kV, 150 kV (existing in Greece and Turkey), and 110 kV voltage levels is implemented in the model.

In order to analyze market perspectives in SEE from the network security point of view, Regional Transmission System Models for 2030 was updated according to the results of the market simulations and analyses (Figure 147). Analyses on the PSS/E RTSM should provide insight on capability of SEE transmission grid to handle various cases of generation dispatch identified in the market study (different load flow patterns that are outcome of the potential market coupling in SEE).

The aim of this Study is to recognize possible network congestions as a consequence of perspective market coupling in SEE and to identify priority investments or to emphasize the importance of "on-time" realization of the selected ongoing projects in transmission systems and interconnections needed to improve reliability of the regional power system, enhance electricity trade in the region and support higher market benefits.

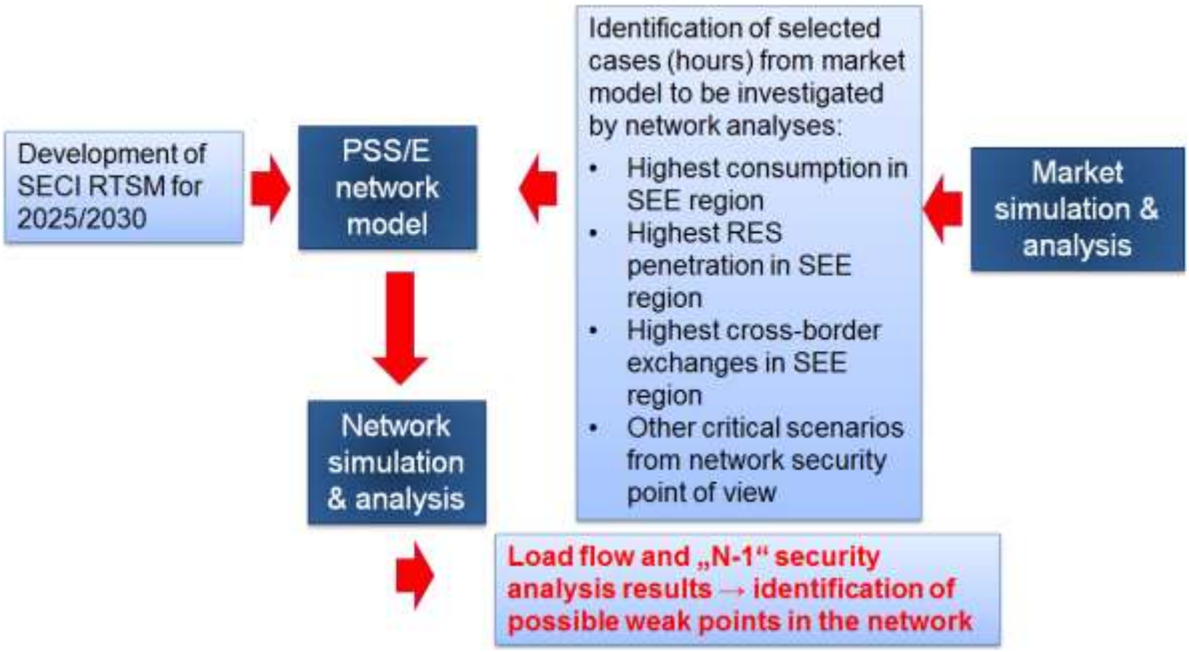



*Figure 147: Creation of network models for Study analyses*

All system states in which branches are loaded beyond thermal limit (overloaded), by full topology or (n-1) contingency analyses are treated as "insecure states" and referenced as such in the present study.

Voltages are also monitored in full topology as well as in (n-1) contingency cases, but voltages out of limits are not treated as limiting factor, because usually such problems have local characters. Voltage level limits are presented in the Table 47. These limits are used in load flow calculations as well as in contingency analysis.

*Table 47: Defined limits for voltage levels*

| | Defined voltage levels | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 750 kV | | 400 kV | | 220 kV | | 150 kV | | 110 kV | | Generator | |
| | min | max | min | max | min | max | min | max | min | max | min | max |
| kV | 712 | 787 | 380 | 420 | 198 | 242 | 135 | 165 | 99 | 121 | | |
| p.u. | 0,95 | 1,05 | 0,95 | 1,05 | 0,90 | 1,10 | 0,90 | 1,10 | 0,90 | 1,10 | 0,95 | 1,05 |

These limits are defined according to the operational and planning standards used in the monitored region, and they are used for full topology and "n-1" analyses. Although wider voltage limits are allowed in emergency conditions for some voltage levels, these are not taken into consideration.

The list of contingencies included internal branches in systems of Albania, B&H, Bulgaria, Croatia, Macedonia, Montenegro, Romania, Serbia, Slovenia as well as tie-lines between these countries. Voltage levels of these branches are as follows:

- all interconnection lines 400 kV, 220 kV and 110 kV;
- all internal lines 400 kV and 220 kV;
- all transformers 400/220 kV.

In case of parallel branches, outage of one branch is considered. All branches which are included in list of outages are also monitored.

Internal lines 110 kV as well as transformers 400/110 and 220/110 kV were considered as of local importance.

Current thermal limits are used as rated limits for lines and transformers. These limits are established on the basis of a temperature to which conductor is heated by current above which either the conductor material would start being softened or the clearance from conductor to ground would drop beyond permitted limits. In these analyses, conductor current must not reach limits imposed by thermal limit defined for conductors material and cross-section according to the IEC standard (50) 466: 1995 – International Electrotechnical Vocabulary - Chapter 466: Overhead Lines.

For some lines in the models, current limits are defined by other equipment (mostly by measurement transformers) or protection settings. Such limits were imposed by owner TSO with explanation that such limiting equipment was not included in plants for replacement (upgrade). For transformers, installed rated MVA power is used as thermal limit. Every branch with current above its thermal limit is treated as overloaded.

Two characteristic scenarios, related to perspective HVDC commissioning in the SEE region, are analyzed (each scenario has three study cases):

- **Base case scenario:** with existing HVDC Greece-Italy and HVDC Montenegro-Italy (under construction)
  1) Highest consumption in SEE region (critical from network security point of view)
  2) Highest RES penetration in SEE region (critical from network security point of view)
  3) Lowest Consumption in SEE region (critical from voltage profile point of view)
- **Alternative scenario:** with existing HVDC Greece-Italy, HVDC Montenegro-Italy (under construction), HVDC Croatia-Italy and HVDC Albania-Italy
  1) Highest consumption in SEE region (critical from network security point of view)
  2) Highest RES penetration in SEE region (critical from network security point of view)
  3) Lowest Consumption in SEE region (critical from voltage profile point of view)

### 7.1.1 Short description of creation of SEE regional network models in PSS/E

For purpose of this study it was necessary to create Regional Transmission System Models (RTSMs) for target year 2030.

National models from TSOs who are member of the SECI project have been collected. In addition, EKC has prepared national models for surrounding area, i.e. models of Austria, Hungary, Ukraine (Burshtin Island only) and North-East Italy.

All of the models have been prepared according the Guidelines for construction of regional model, which was adopted in SECI project, thus providing following advantages of the models:

- Each country/TSO model has its own area number as well as ranges for node number, owners and zones;
- All generators are modeled at generation voltage level and connected to transmission network via step-up transformers;
- Network models consist of all voltage levels 110 kV and above (in some national/TSO models even lower voltage levels are modeled);
- There are no any simplification of network in area of interest (every single element is modeled).

After collection of all national/TSOs models, each model has been checked and corrected (when necessary) and then imported into RTSM.

Besides standard load flow and n-1 security analysis, evaluation of proposed project's influences on transmission network in SEE region is conducted by using TOOT methodology. TOOT (Take Out One at the Time) method consists of excluding grid element projects from the forecasted network structure on a one–by–one basis and to evaluate the load flows over the lines with and without the examined network reinforcement (a new line, a new substation, a new PST, ...).

## 7.2 Load flow pattern changes

In the process of model construction for defined characteristic regimes, it was noticed that there were differences in usual load flow patterns, characteristic for SECI RTSM 2030 Winter Maximum model - starting model for construction of other characteristic regimes. Original SECI RTSM has moderate level of exchanges (national systems are more or less balanced and have exchange pattern typical for today's conditions). With such approach, model have universal application – it could be adopted easily for different (almost any kind) level of exchanges.

On Figure 148, differences in total exchanges per country between all three characteristic regimes and starting SECI RTSM 2030 Winter Maximum model are shown. It can be seen that for some countries, like Albania, Montenegro, Serbia and Slovenia, market analysis have shown that for Highest Consumption and Highest RES penetration regime, this countries are importers rather than exporters at is initially presumed. For other countries, like Greece and Macedonia, the situation is opposite. For other countries, exports or imports are properly presumed and the only difference is the total amount of export or import. Comparison with initial SECI RTSM 2030 Winter Maximum model is only justifiable for Highest Consumption and Highest RES penetration regimes, as these two regimes are also identified for winter period. As Lowest Consumption regime is not identified for winter period, comparing it to initial SECI RTSM Winter Maximum model is not that justifiable. It would make more sense to compare this model with SECI RTSM Summer Minimum, but unfortunately, this model was still under development when analysis for this study were performed.

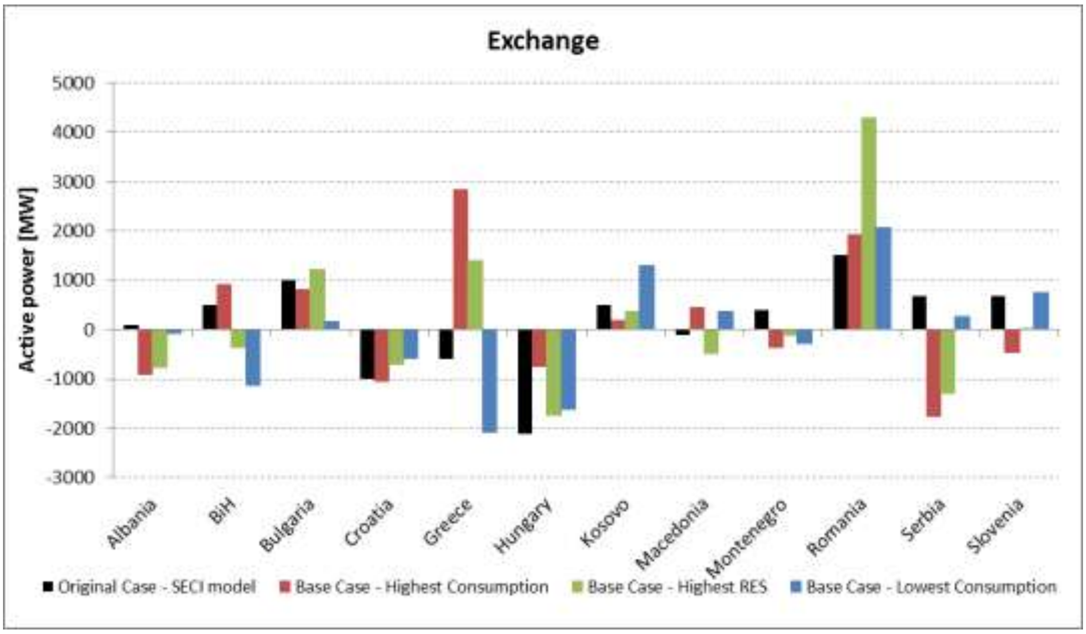
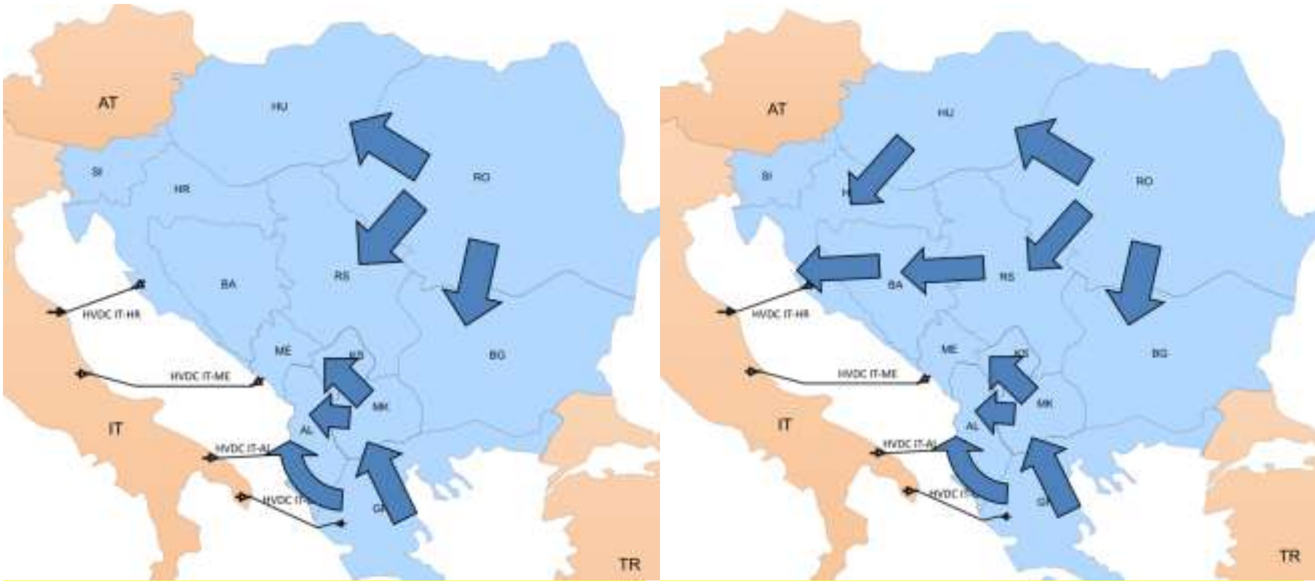



*Figure 148: Active power exchange of the SEE region*

Significant changes in load flow patterns are also recognized for Highest Consumption and Highest RES penetration regime, when compared to SECI RTSM 2030 Winter Maximum regime. For Highest Consumption and Highest RES penetration regimes, following larger differences in cross-border power flows are noticed:

- Flows from Hungary to Croatia are increased from 850 MW in Base Case, to 1150 MW in Alternative Case.
- Flows from Romania to Serbia are increased from 600 MW in Base Case to 1150 MW in Alternative Case
- Flows from Greece to Albania are increased from 600 MW in Base Case to 800 MW in Alternative Case
- Flows from Bosnia and Herzegovina towards Croatia are decreased by 500 MW in Base Case and increased by 500 MW in Alternative Case.
- Flows in all analyzed regimes are in direction from Bosnia and Herzegovina to Montenegro, while it is opposite in SECI RTSM model
- Flows in all analyzed regimes are in direction from Greece to Macedonia, while it is opposite in SECI RTSM model

The biggest cross-border flow differences between SECI RTSM model and models based on market studies are shown on the Figure 149.




**Base Case** **Alternative Case**

*Figure 149: Load flow pattern for Base case and Alternative case*

It should also be pointed out that Base Case models are more comparable to SECI RTSM initial model, than Alternative Case model, because in Alternative Case models four HVDC links are in operation while in SECI RTSM and Base Case models, only two of them are in operation. Nevertheless, market based models show significant differences in load flow patterns when compared to model based on information from each TSO's National Development Plan. Main reasons of such differences are in first place:

- market integration
- different initial assumption of countries balances
- different RES production profile.

## 7.3 Base Case analysis

As stated in previous chapters, Base Case scenario assumes operation of two HVDC links between SEE region and Italy:

- Existing HVDC link GR-IT, and
- Planned HVDC link ME-IT.

For this scenario, three characteristic regimes have been analyzed in details:

- Highest consumption (18th of December 2030, 18:00h),
- Highest RES penetration (9th of December 2030, 11:00h),
- Lowest consumption (28th May 2030, 03:00h).

Differences in characteristic regimes in terms of generation, consumption and total exchanges per country are shown on following figures.

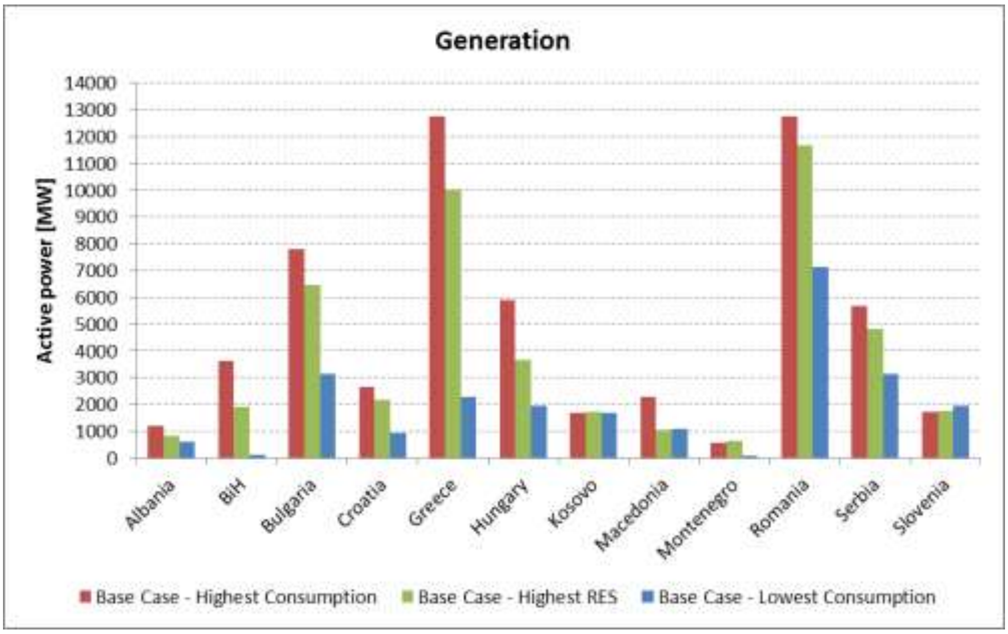



*Figure 150: Generation per country for base case regimes*

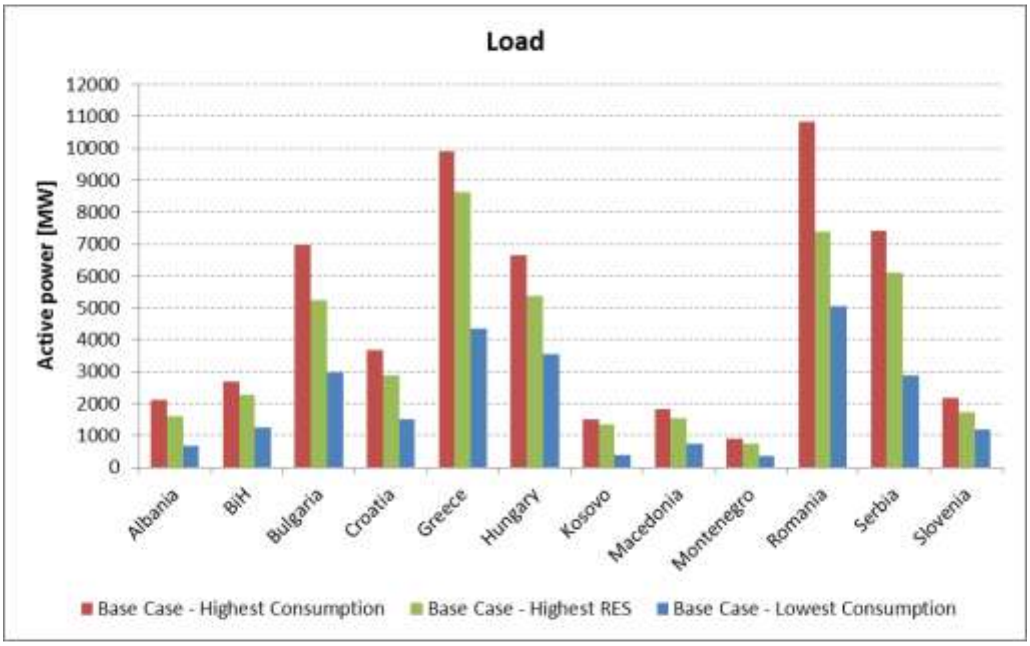



*Figure 151: Consumption per country for base case regimes*

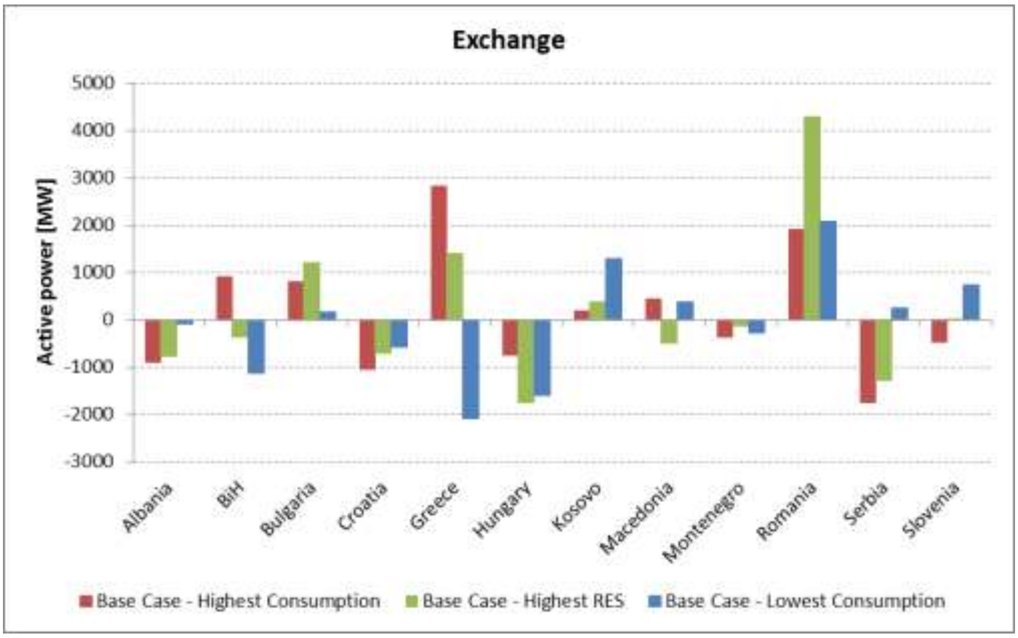



*Figure 152: Total exchanges per country for base case regimes*

In following chapter, results of load flow calculation, voltage profile assessment and n-1 contingency analysis for Base Case regimes are shown.

## 7.3.1 Base Case Regime 1 - Highest consumption

### 7.3.1.1 Load flow and voltage profile analysis

Table 48 shows total production, consumption and exchange per country for Base Case Highest Consumption regime, which were results of previously conducted market analyses.

*Table 48: Area summary for Base Case Highest Consumption regime*

| Base Case - Highest Consumption regime | Generation (MW) | Consumption (MW) | Exchange (MW) |
|---|---|---|---|
| Albania | 1196 | 2103 | -907 |
| BiH | 3611 | 2701 | 910 |
| Bulgaria | 7792 | 6979 | 813 |
| Croatia | 2647 | 3694 | -1047 |
| Greece | 12744 | 9911 | 2833 |
| Hungary | 5884 | 6641 | -757 |
| Kosovo | 1695 | 1514 | 181 |
| Macedonia | 2280 | 1838 | 442 |
| Montenegro | 550 | 913 | -363 |
| Romania | 12738 | 10824 | 1915 |
| Serbia | 5663 | 7422 | -1758 |
| Slovenia | 1723 | 2186 | -463 |

Load flow analysis results, obtained for Base Case - Highest Consumption regime, show significant differences in total cross-border exchange between aggregated physical flows and market based program cross-border flows. Aggregated program exchanges as a result of the market study are shown on Figure 153, while aggregated physical exchanges among analyzed countries are presented on Figure 154.

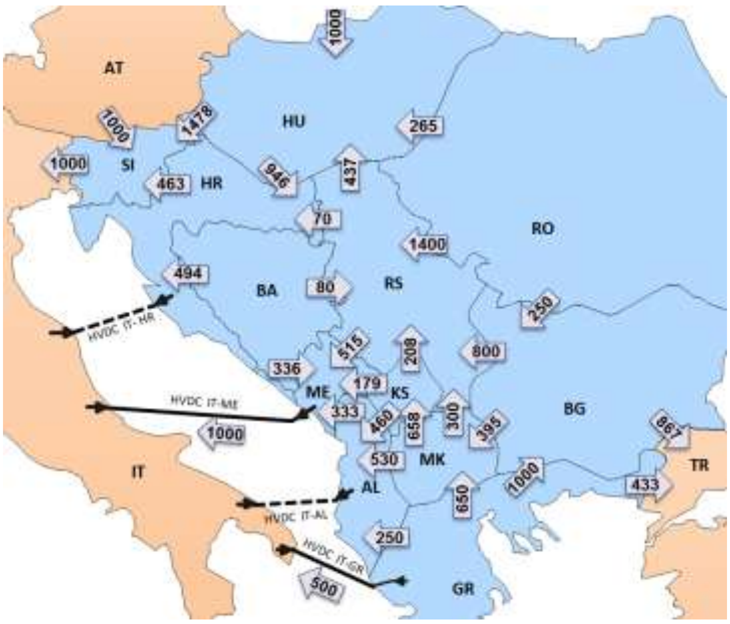



*Figure 153: Aggregated program exchanges in Base Case scenario, Highest Consumption regime*

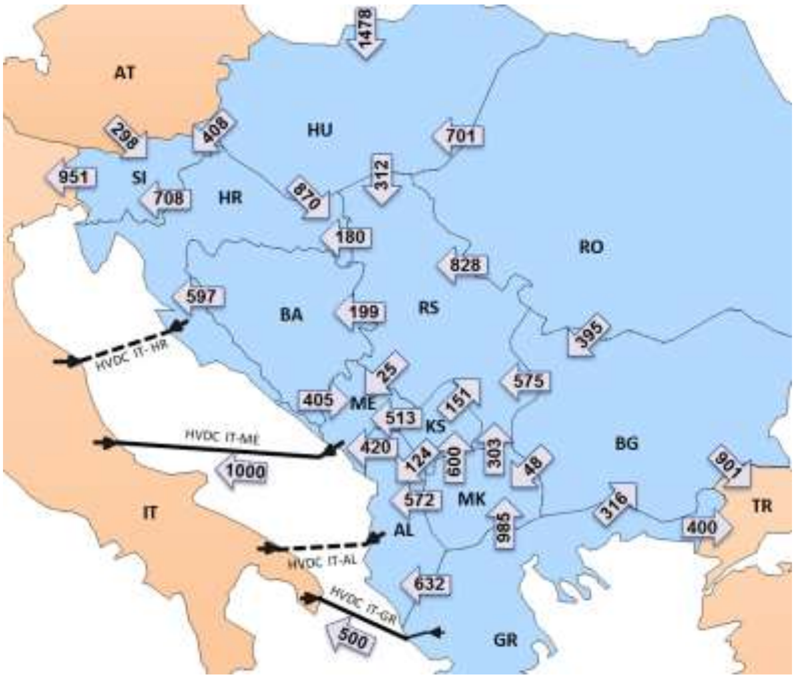



*Figure 154: Aggregated physical cross-border flows in Base Case scenario, Highest Consumption regime*

From previous figures, it can be seen that main reason of differences between physical cross-border flows and cross-border exchanges which were results of market analysis, is that in some cases, exchange between two countries is realized via transmission network of other countries, i.e. by so called "loop flows". One such example is exchange between Romania and Serbia, i.e. while in market simulations this exchange is supposed to be 1400 MW in direction to Serbia, load flow analysis shows that this exchange is around 828 MW, but with additional increase of flows from Romania via Hungary (from 265 MW to 701 MW) towards Serbia.

It can be seen from Figure 154 that in general, highest cross-border flows are registered from Romania to its neighboring countries, as well as from Greece to other power systems, as these two countries are dominant exporters in this regime.

Besides high level of flows between these countries, due to sufficient cross-border capacities of interconnection lines, transmission network in these parts of the region is not overloaded.

Transmission network of 750 kV, 400 kV and 220 kV voltage levels was considered in load flow analysis, while lower voltage levels were not analyzed in details as they were considered to be of local importance. Load flow analysis has shown that there are no overloaded elements in region of interest in Base Case High Consumption regime.

Also, the analysis has shown that there were no voltages of bus bars outside permitted limits in this regime.

The voltage profile diagram of the analyzed network of interest is shown on Figure 155.

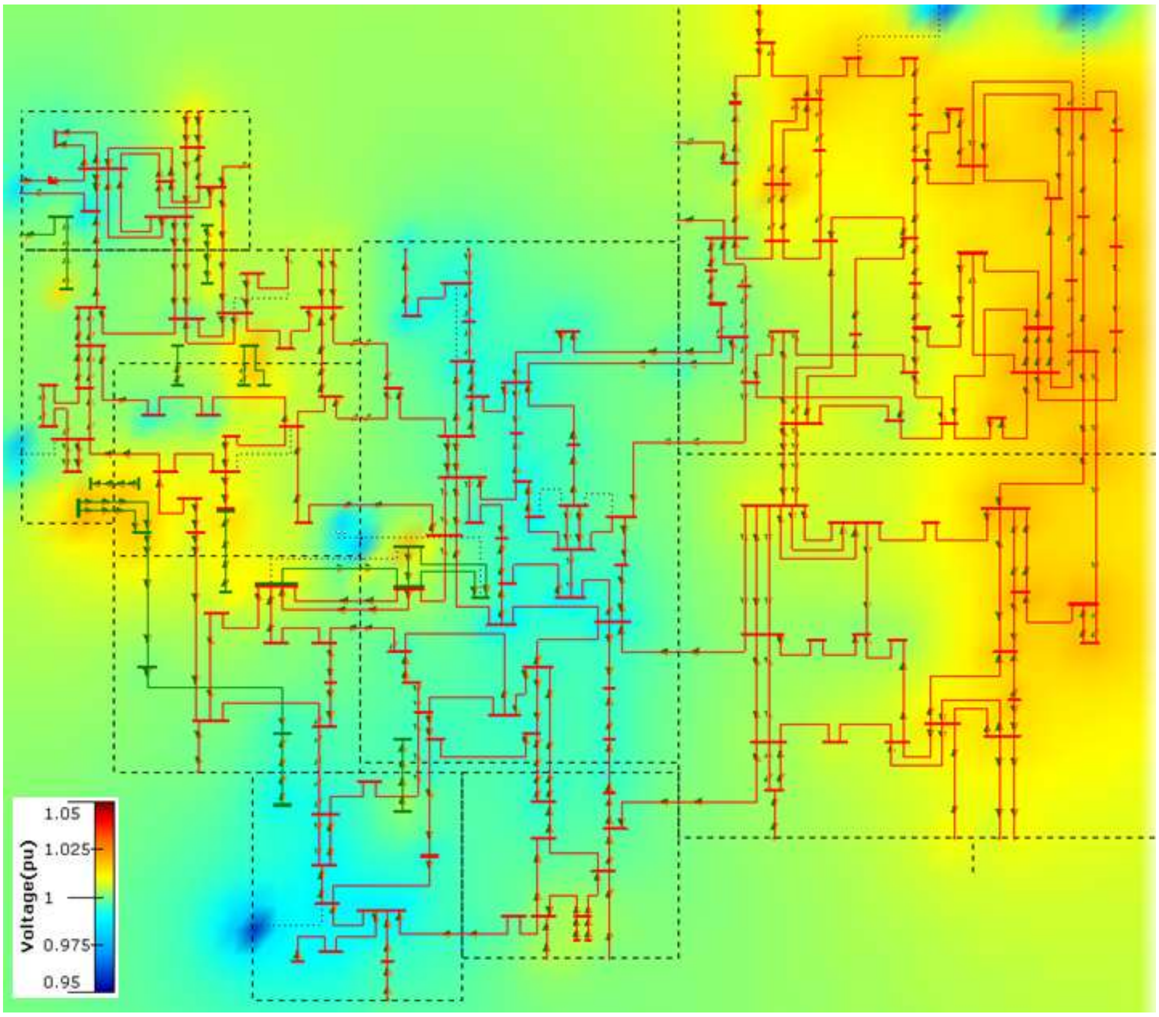



*Figure 155: Voltage profile diagram for the network of interest for the base case scenario, highest consumption*

#### 7.3.1.2 Contingency (n-1) analysis

In contingency analysis conducted for this regime, transmission network in SEE region, starting from 220 kV and above, was subjected to outages of transmission lines of 750 kV, 400 kV and 220 kV voltage levels, as well as to outages of transformers 750/x kV, 400/x kV and 220/x kV. The analysis has shown that the only significant overloadings which were registered are overloadings of transformers in several substations, i.e. in such substations, if one transformer trips the remaining one becomes overloaded. These overloadings are consequence of load scaling and just show potential lack of transformer capacity in some substations, so they are not of regional importance.

Based on previous findings, it can be concluded that for 2030 High Consumption regime, transmission network in SEE region satisfies n-1 security criteria, in integrated market conditions.

#### 7.3.1.3 Sensitivity (n-1) analysis

From Figure 154, it can be seen that in some parts of the network load flows are higher than in other parts and therefore, transmission network in these regions is subjected to more stress. Because of that, reinforcements planned in these regions are of greater influence to the rest of the transmission network. Not implementing reinforcements on those corridors would have more negative effects than some other proposed projects. In this chapter, additional sensitivity analysis for Highest Consumption regime is conducted for cases when some proposed projects are not taken into consideration. Evaluation of proposed projects influences on transmission network in SEE region is conducted by using TOOT methodology.

First project which is taken out of the model in order to assess its influence on overall (n-1) security analysis was new 400 kV interconnection OHL Pancevo (RS) – Resita (RO). Mid Continental East corridor (Project 144/238) - the project consists of one double circuit 400 kV line between Serbia and Romania and reinforcement of the network along the western border in Romania: one new single circuit 400 kV line from Portile de Fier to Resita and upgrade from 220 kV double circuit to 400 kV double circuit of the axis between Resita and Arad, including upgrade to 400 kV of three substations along this path (Figure 156).

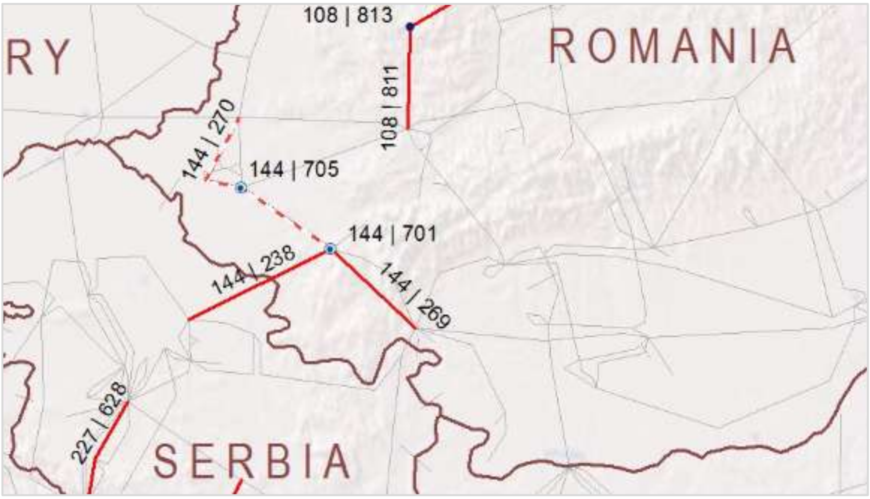


*Figure 156: Project 144/238 - Mid Continental East corridor (Pancevo - Resita)*

When this project is not considered in (n-1) security analysis, all interchange between Romania and Serbia is conducted via only one remaining 400 kV interconnection line Djerdap (RS) – Portile de Fier (RO). Due to large increase of power flows in this direction, in case of outages of 400 kV lines in Eastern Serbia remaining 400 kV lines in this region will become overloaded. Because of this, project 400 kV new interconnection OHL Pancevo (RS) – Resita (RO) is shown to be of significant importance in analyzed market coupled conditions in SEE region.

Second project which is considered in sensitivity analysis is new 400 kV Banja Luka (BA) – Lika (HR). This new interconnection OHL is a part of a wider project which in Croatia also includes a new 400 kV OHL replacing the aging 220 kV OHL between existing substations Brinje and Konjsko, interdepending with the construction of two new 400/(220)/110 kV substations Brinje and Lika (Figure 157). When this project was not taken into consideration, (n-1) contingency analysis has not reported any additional overloadings in this region, when compared with the case when this project was considered.

Figure 157:Project 136/227 – 400 kV interconnection between Bosnia and Herzegovina and Croatia

Third project which is considered in sensitivity analysis is the new 400 kV interconnection OHL Bitola (MK) – Elbasan (AL). New cross-border single circuit 400kV OHL between Macedonia and Albania, with the new 400/110 kV substation in in Ohrid, connected in/out to the new 400 kV line Bitola-Elbasan (Figure 158).

Figure 158: Project 147/239 – 400kV interconnection between Macedonia and Albania

When this project was not taken into consideration, (n-1) contingency analysis has not reported any additional overloadings in this region, when compared with the case when this project was considered.

Fourth project which is considered in sensitivity analysis is the new 400 kV interconnection RS-BA-ME. Trans Balkan Corridor (Project 227) - upgrade of transmission network in Western Serbia at 400 kV voltage level between SS Obrenovac and SS Bajina Basta, which implies new double 400 kV OHL SS Obrenovac – SS Bajina Basta, reconstruction of existing SS Obrenovac and SS Bajina Basta. New 400 kV interconnection between Serbia, Bosnia and Hercegovina and Montenegro, which implies double 400 kV OHL between SS Bajina Basta, SS Visegrad (BiH), and SS Pljevlja (Montenegro), shown on Figure 159.


*Figure 159: Project 227/628 - Transbalkan Corridor*

When this project was not taken into consideration, (n-1) contingency analysis has not reported any additional overloadings in this region, when compared with the case when this project was considered.

## 7.3.2 Base Case Regime 2 - Highest RES penetration

### 7.3.2.1 Load flow and voltage profile analysis

Table 49 shows total production, consumption and exchange per country for Base Case Highest RES penetration regime, which were results of previously conducted market analyses.

*Table 49: Area summary for Base Case Highest RES penetration regime*

| Base Case - Highest Consumption regime | Generation (MW) | Consumption (MW) | Exchange (MW) |
|---|---|---|---|
| Albania | 826 | 1599 | -773 |
| BiH | 1921 | 2288 | -367 |
| Bulgaria | 6442 | 5236 | 1206 |
| Croatia | 2173 | 2877 | -704 |
| Greece | 10012 | 8618 | 1394 |
| Hungary | 3645 | 5385 | -1740 |
| Kosovo | 1715 | 1341 | 374 |
| Macedonia | 1038 | 1527 | -489 |
| Montenegro | 628 | 750 | -122 |
| Romania | 11679 | 7379 | 4300 |
| Serbia | 4820 | 6111 | -1291 |
| Slovenia | 1754 | 1742 | 12 |

As for Highest Consumption regime, load flow results, obtained for Base Case - High RES penetration regime, also show significant differences in total cross-border exchange between aggregated physical flows and market based program cross-border flows. Aggregated program exchanges as a result of the market study are shown on Figure 160, while aggregated physical exchanges among analyzed countries are presented on Figure 161.

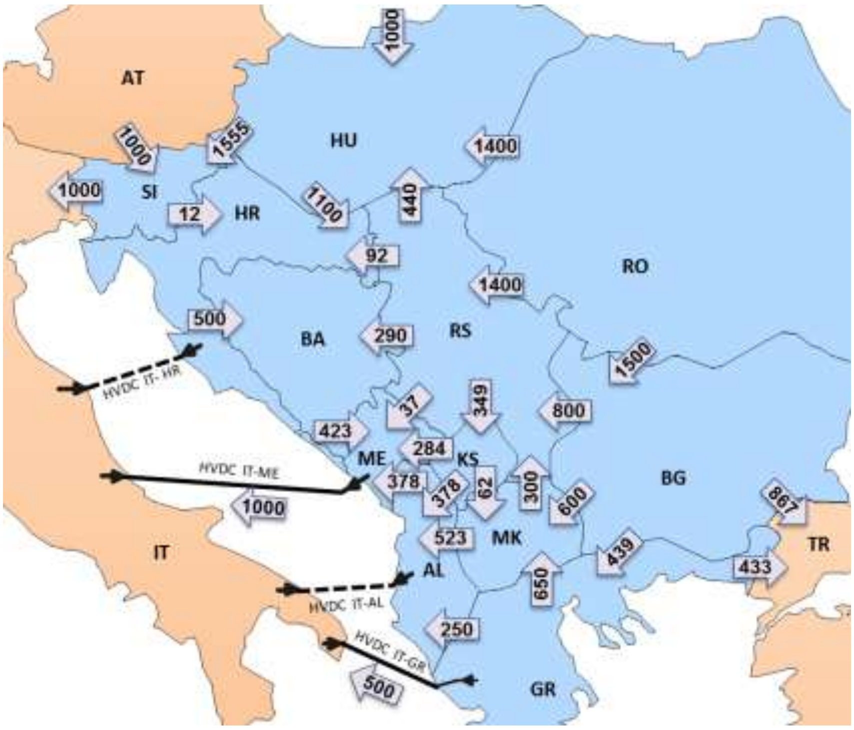



*Figure 160: Aggregated program exchanges in Base Case scenario, Highest RES regime*

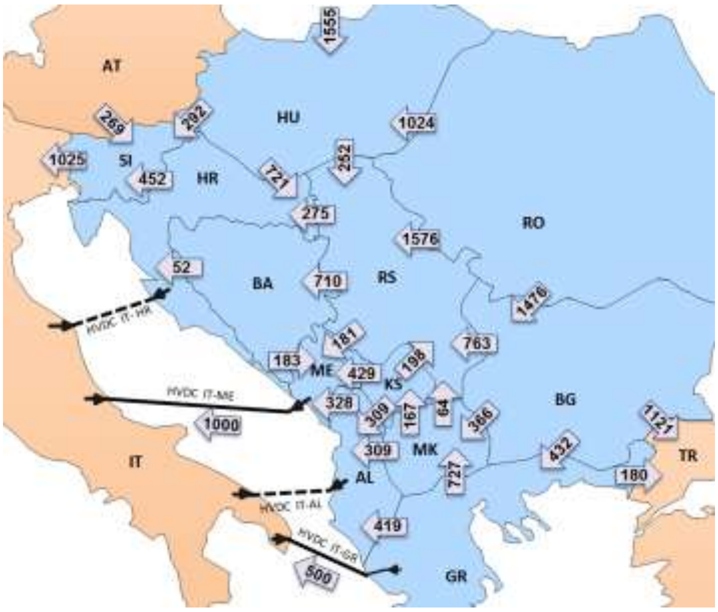



*Figure 161: Aggregated border flows in area of SEE in Base Case scenario, Highest RES regime*

As in previous regime, there are differences between physical cross-border flows and cross-border program exchanges which were results of market analysis, mainly due to loop flows. In Highest RES regime, Romania is the biggest exporter among other countries in the SEE region and therefore, highest cross-border flows are from Romania to Serbia, Bulgaria and Hungary. Significant power flow is registered from Macedonia to Kosovo, from Bulgaria to Turkey and from Greece to Macedonia.

In assessment of element loading, transmission network of 750 kV, 400 kV and 220 kV voltage levels was considered, while lower voltage levels were not analyzed in details as they were considered to be of local importance. Load flow analysis has shown that there are no overloaded elements in region of interest in Base Case High RES penetration regime.

Also, the analysis has shown that there were no voltages of bus bars outside permitted limits in this regime.

The voltage profile diagram of the analyzed network of interest is shown in Figure 162.

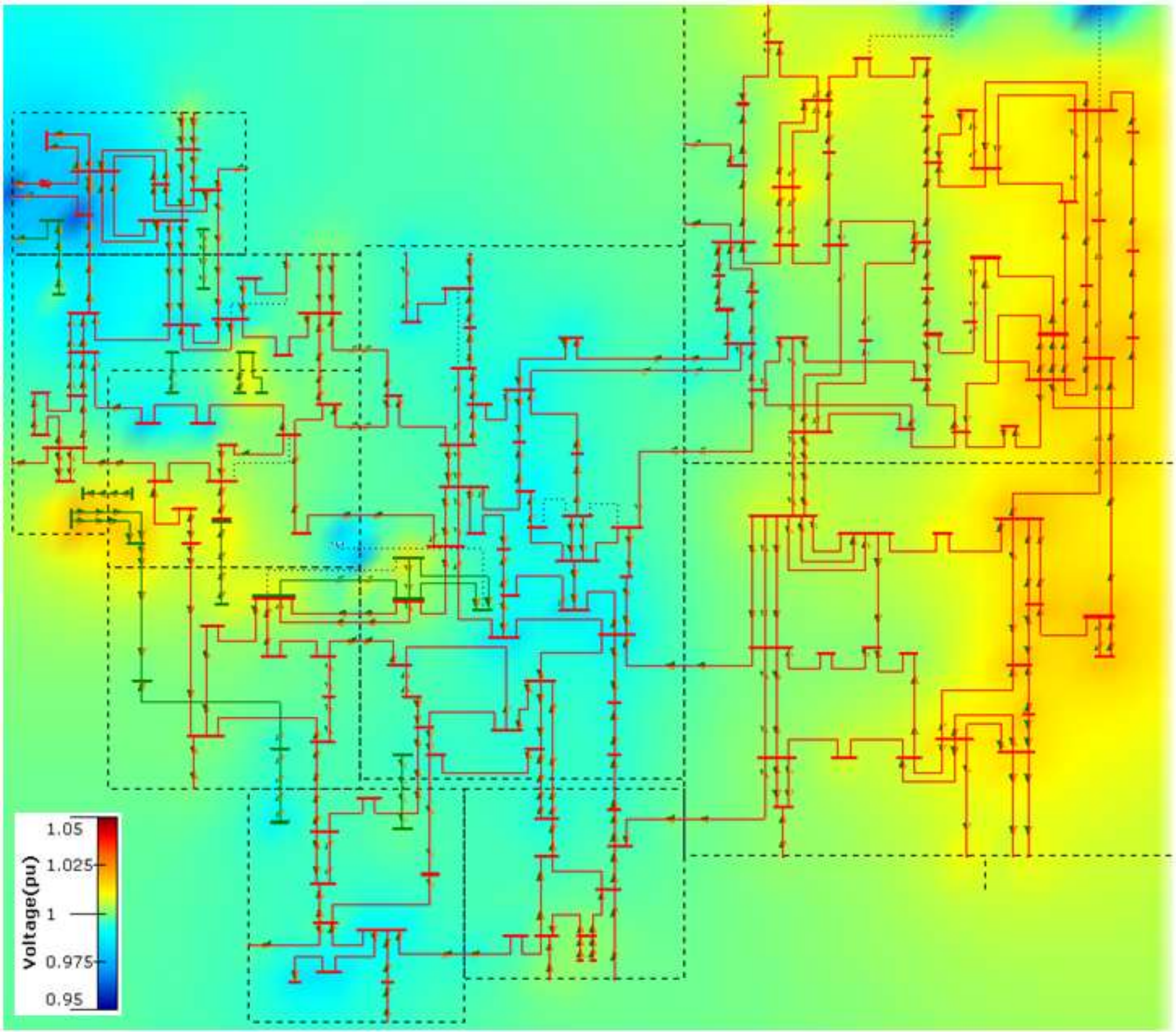



*Figure 162: Voltage profile diagram for the network of interest for the base case scenario, highest RES*

#### 7.3.2.2 Contingency (n-1) analysis

Because of significant power flows from Romania to Serbia in Base Case – Highest RES penetration regime, western parts of Romanian transmission network, as well as eastern parts of Serbian transmission network are highly loaded. In such conditions, in case of outage of 400 kV OHL Portile de Fier – Resita in Romania, interconnection line Djerdap (RS) – Resita (RO) becomes overloaded (108%). Also, in the case of the same outage 400/220 kV transformer in SS Resita becomes overloaded (102%). However, it should be noticed that line rating of Serbian side (1800 A) of this interconnection OHL is lower than line rating of Romanian side (2195 A) of the line in the load flow model. If the rating of both halves of the interconnection line was set to higher of these two values then in case of previously mentioned outage it would not be overloaded. In rest of the transmission network of interest, there are no overloadings of regional interest.

#### 7.3.2.3 Sensitivity (n-1) analysis

As for previous Base Case regime, in Highest RES penetration regime additional sensitivity analysis was conducted. The influence of individual projects on resilience of the rest of the transmission network is analyzed.

When project new 400 kV OHL Pancevo (RS) – Resita (RO) is not considered in High RES penetration regime, due to previously mentioned high flows from Romania to Serbia, interconnection line 400 kV Djerdap (RS) – Portile de Fier (RO) becomes overloaded in base case, even with previously mentioned higher line rating. After conducting (n-1) analysis, several 400 kV transmission lines in eastern Serbia are reported as overloaded, among which 400 kV interconnection line Nis (RS) – Sofia West (BG). Also, several 220 kV transmission elements in western Romania are reported as overloaded in case of outages. Because of previous findings, project new 400 kV OHL Pancevo (RS) - Resita (RO) is shown to be of high importance to overall network security also in Highest RES penetration regime.

Not considering projects new 400 kV Banja Luka (BA) – Lika (HR), new 400 kV Bitola (MK) – Elbasan (AL) and new 400 kV interconnections RS-BA-ME, did not introduce any additional overloadings in the transmission network of interest.

### 7.3.3 Base Case Regime 3 – Lowest consumption

#### 7.3.3.1 Load flow and voltage profile analysis

Table 50 shows total production, consumption and exchange per country for Base Case Lowest Consumption regime, which were results of previously conducted market analyses.

*Table 50: Area summary for Base Case Lowest Consumption regime*

| Base Case - Highest Consumption regime | Generation (MW) | Consumption (MW) | Exchange (MW) |
|---|---|---|---|
| Albania | 607 | 691 | -84 |
| BiH | 102 | 1240 | -1138 |
| Bulgaria | 3128 | 2970 | 158 |
| Croatia | 937 | 1518 | -581 |
| Greece | 2271 | 4359 | -2088 |
| Hungary | 1949 | 3560 | -1611 |
| Kosovo | 1683 | 393 | 1291 |
| Macedonia | 1107 | 732 | 375 |
| Montenegro | 72 | 359 | -287 |
| Romania | 7124 | 5051 | 2073 |
| Serbia | 3135 | 2873 | 263 |
| Slovenia | 1930 | 1189 | 741 |

As for previous Base Case regimes, load flow analysis results for Base Case - Lowest Consumption regime, show significant differences in total cross-border exchange between aggregated physical flows and market based program cross-border flows. Aggregated program exchanges as a result of the market study are shown on Figure 163, while aggregated physical exchanges among analyzed countries are presented on Figure 164.

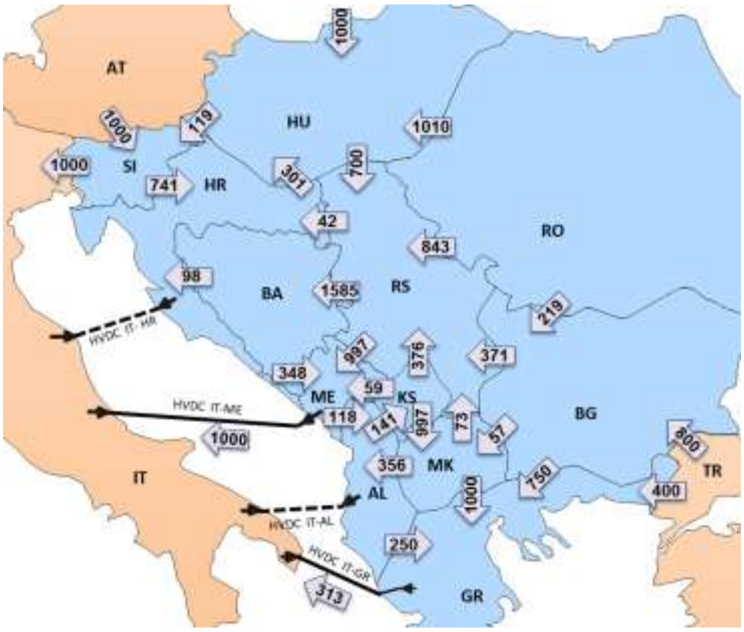



*Figure 163: Aggregated program exchanges in Base Case scenario, Lowest Consumption regime*

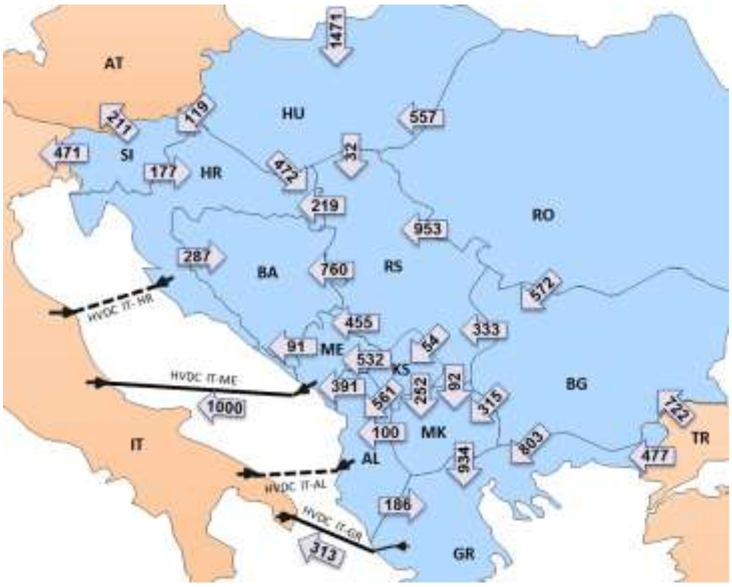



*Figure 164: Aggregated border flows in area of SEE in Base Case scenario, Lowest Consumption regime*

As in previous regimes, there are differences between market based program exchanges and physical cross-border flows which are results of load flow analysis. Same as in previous regime, biggest aggregated physical cross-border power flows in the region of interest are registered from Romania to Serbia, but also from Kosovo to Montenegro, from Macedonia to Greece and from Bulgaria to Greece. Opposite to previous regimes, Greece is now a large importer of electric energy which causes large cross-border flows coming from Macedonia and Bulgaria. Besides Romania, in this regime Kosovo is also a significant exporter which results in large power flows shown on Figure 164.

Load flow results for Base Case – Lowest Consumption regime have shown that there are no overloaded elements in the transmission network of interests. When analyzing loading of elements, 400 kV and 220 kV transmission lines and 400/x kV and 220/x kV transformers were considered, while elements of lower voltage levels were not analyzed in details, as it is taken to be of local importance.

Regarding voltage profile assessment for Base Case - Lowest Consumption regime, it should be pointed out that in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initial voltage values. Because of low loading, much of the transmission lines initially generated additional reactive power causing voltage values higher than permitted which gave infeasible solution. Because of that, existing shunt reactors were put in operation and many generator units were set to operate in under excitation regime, which corresponds to usual operational practice in analyzed power systems. Implementation of such measures gave feasible load flow solution with voltage levels in permitted operational ranges.

The voltage profile diagram of the analyzed network of interest is shown in Figure 165.

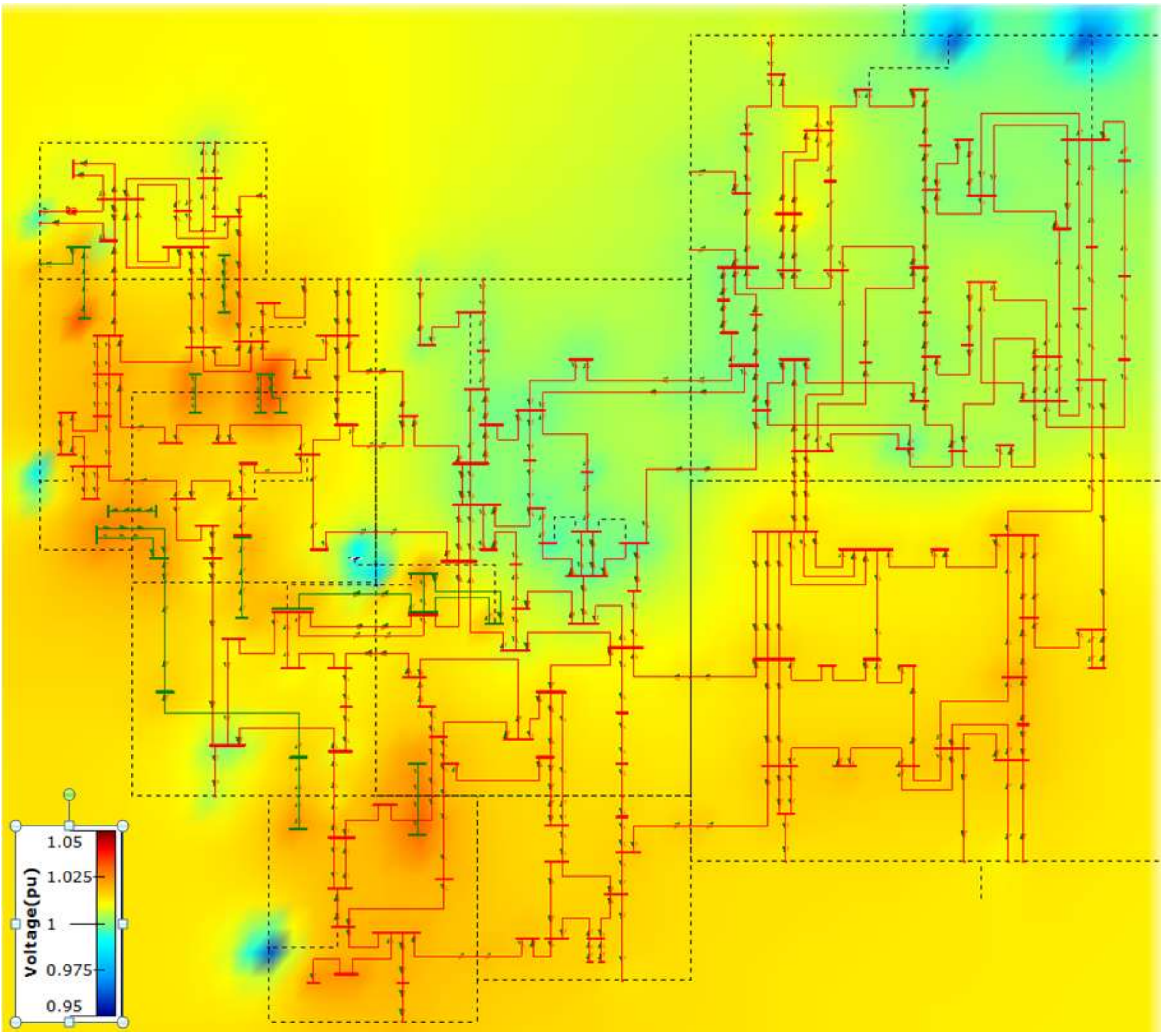


*Figure 165: Voltage profile diagram for the network of interest for the base case scenario, lowest consumption*

#### 7.3.3.2 Contingency (n-1) analysis

Due to much lower levels of total generation and demand per country in Lowest Consumption regime when compared to two previous regimes, transmission network elements in this regime are much less loaded in base case. Therefore, results of (n-1) contingency analysis have shown that in this regime, there are no transmission network elements of interest which are overloaded.

#### 7.3.3.3 Sensitivity (n-1) analysis

Because of low loading of transmission network elements, even in the case when individual projects like new 400 kV OHL Pancevo (RS) – Pesita (RO), new 400 kV OHL Banja Luka (BA) – Lika (HR), new 400 kV OHL Bitola (MK) – Elbasan (AL) and new 400 kV interconnection RS-BA-ME, are not taken into consideration in Base Case – Low Consumption regime, there are no overloading of transmission network elements in (n-1) contingency situations.

### 7.3.4 Base Case Regimes - Summary

For all Base Case regimes, it can generally be concluded that market coupling in SEE region introduces changes in load flow patterns. Changes in power flows in transmission networks of the SEE region do not lead to overloadings in case when all elements are in operation. In such network topology conditions, voltage levels were in permitted ranges for Highest Consumption and Highest RES penetration regimes. For Lowest Consumption regime, in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initial unfeasibly high values of voltages.

Market simulations for Base Case scenarios have shown big congestions, with program flows reaching NTC values for many hours. Grid analysis have shown that, in terms of (n-1) security criteria assessment, Highest RES penetration regime is identified as the most critical one for Base Case scenario. In this regime, outage of 400 kV OHL Portile de Fier (RO) – Resita (RO) causes overloading of 400 kV OHL Djerdap (RS) – Portile de Fier (RO). For other two regimes, Highest Consumption and Lowest Consumption, transmission networks in SEE region satisfy (n-1) security criteria.

Reported congestion on Serbia-Romania border in Highest RES penetration regime, is a strong signal that in order to introduce estimated or higher levels of NTCs for target year between these two countries, additional network reinforcement has to be implemented in order to enhance electricity trade and to support higher social welfare (lower overall energy price).

Sensitivity analysis, conducted for several planned project by applying TOOT methodology, has shown that:

- Project 400 kV OHL Pancevo (RS) – Resita (RO) has shown significant influence on (n-1) security criteria, in Highest Consumption and Highest RES penetration regimes.
- Project 400 kV OHL Banja Luka (BA) – Lika (HR) has shown small influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Bitola (MK) – Elbasan (AL) has shown small influence on (n-1) security criteria, in all analyzed regimes.
- Project new 400 kV interconnections RS-BA-ME has shown small influence on (n-1) security criteria, in all analyzed regimes.

## 7.4 Alternative Case analysis

As stated in previous chapters, Alternative Case assumes operation of four HVDC links between SEE region and Italy:

- Existing HVDC link GR-IT,
- Planned HVDC link ME-IT,
- Planned HVDC link HR-IT, and
- Planned HVDC link AL-IT.

For this scenario, three characteristic regimes have been analyzed in details:

- Highest consumption (18th of December 2030, 18:00h),
- Highest RES penetration (9th of December 2030, 11:00h),
- Lowest consumption (28th May 2030, 03:00h).

Differences in characteristic regimes in terms of generation, consumption and total exchanges per country are shown on following figures.

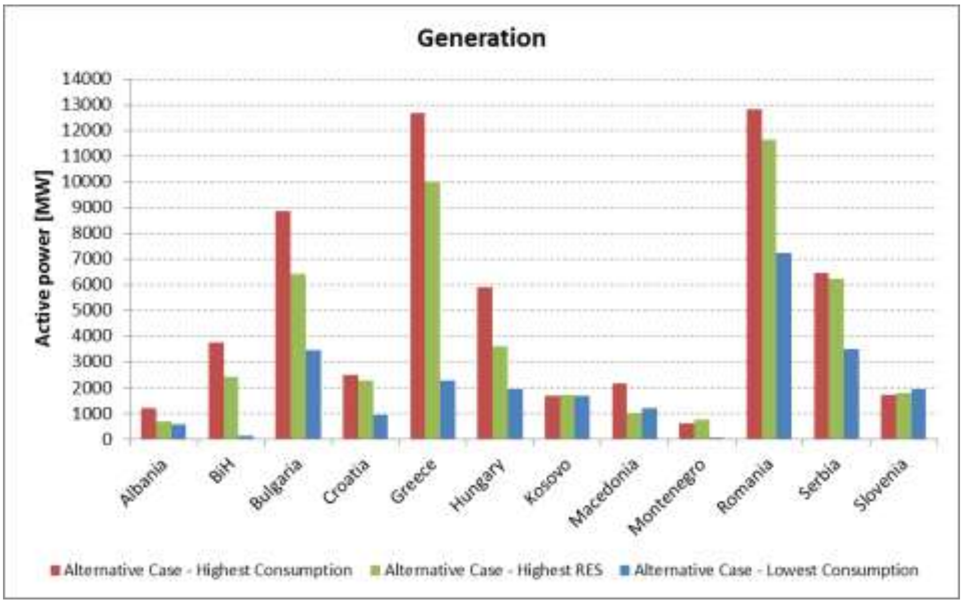



*Figure 166: Generation per country for alternative case regimes*

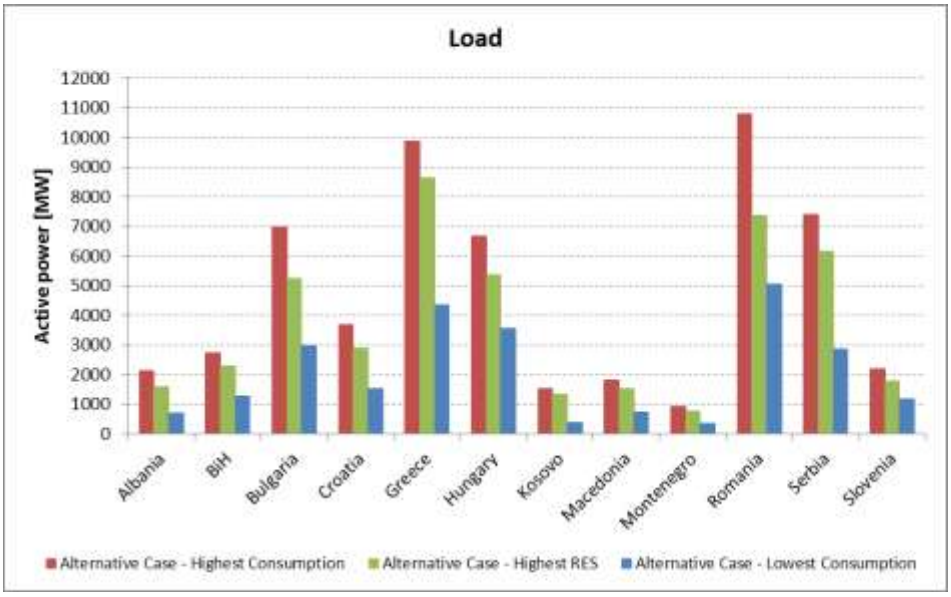



*Figure 167: Consumption per country for alternative case regimes*

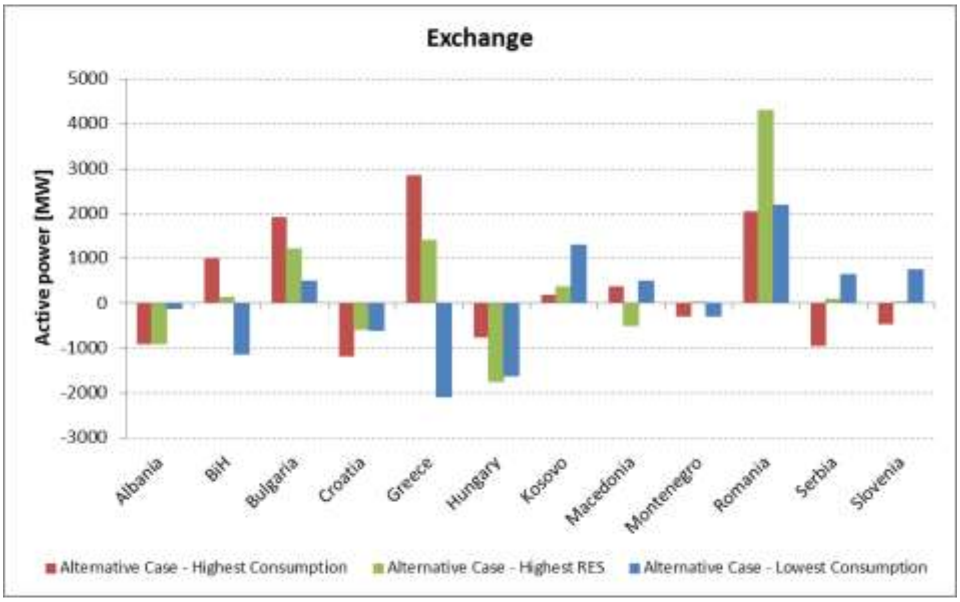



*Figure 168: Total exchanges per country for alternative case regimes*

In following chapters, results of load flow calculation, voltage profile assessment and n-1 contingency analysis for Alternative Case regimes are shown. Besides assessment of individual regime feasibility in terms of transmission element loading, bus bar voltage levels and (n-1) security criteria, influence of two additional HVDC links are also analyzed in details.

Sensitivity analyses have been conducted for Alternative Case regimes, for the same project as for Base Case regimes. Short description of analyzed projects is given in chapter 7.3.1.3.

## 7.4.1 Alternative Case Regime 1 - Highest consumption

### 7.4.1.1 Load flow and voltage profile analysis

Table 51 shows total production, consumption and exchange per country for Alternative Case - Highest Consumption regime, as results of previously conducted market analyses.

*Table 51: Area summary for Alternative Case Highest Consumption regime*

| Alternative Case - Highest Consumption regime | Generation (MW) | Consumption (MW) | Exchange (MW) |
|---|---|---|---|
| Albania | 1224 | 2124 | -900 |
| BiH | 3748 | 2735 | 1013 |
| Bulgaria | 8890 | 6987 | 1903 |
| Croatia | 2514 | 3682 | -1168 |
| Greece | 12692 | 9859 | 2833 |
| Hungary | 5897 | 6654 | -757 |
| Kosovo | 1691 | 1518 | 174 |
| Macedonia | 2186 | 1819 | 367 |
| Montenegro | 626 | 920 | -294 |
| Romania | 12822 | 10787 | 2034 |
| Serbia | 6459 | 7403 | -944 |
| Slovenia | 1744 | 2207 | -463 |

By comparing generation and exchange patter for Base Case and Alternative Case, influence of two additional HVDC links between SEE region and Italy can be analyzed for specific regime. On Figure 169, comparison of total generation per country in Alternative Case and Base Case Highest Consumption regime is presented.

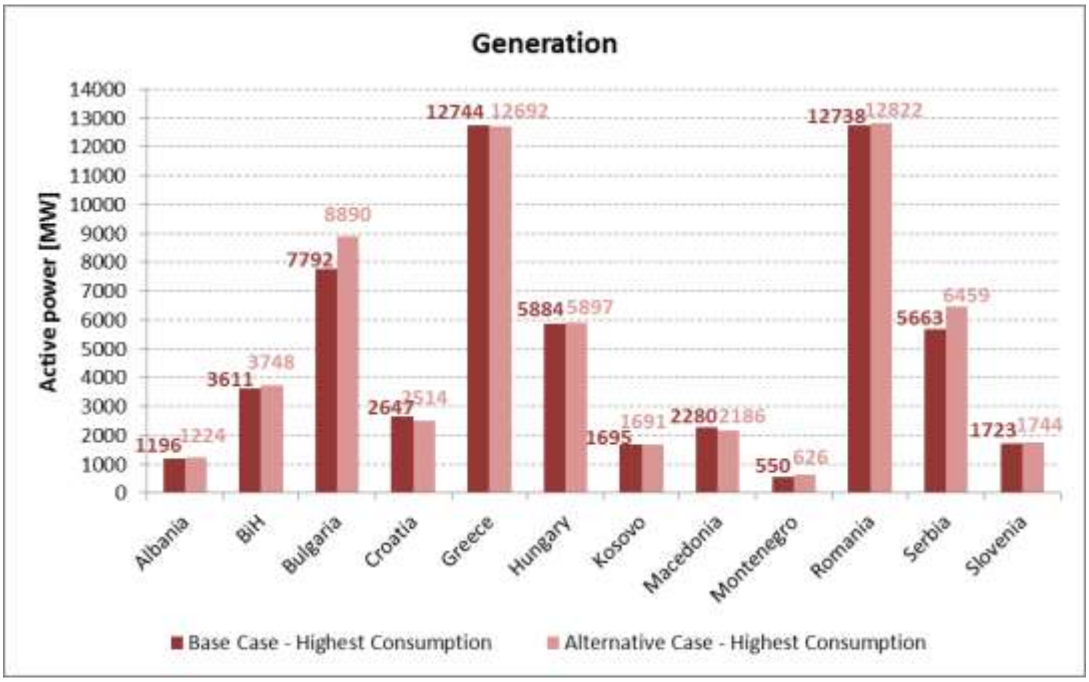



*Figure 169: Generation per country for Alternative Case and Base Case Highest Consumption regime*

From previous figure, it can be seen that with two additional HVDC links HR-IT and AL-IT, consequential market coupling introduces such electricity market conditions that some countries in SEE region change their total generation. For Highest Consumption regime, changes in total generation per country are following:

1. Albania: Increase of generation by 28 MW (+2.3% of total generation)
2. Bosnia and Herzegovina: Increase of generation by 137 MW (+3.6% of total generation)
3. Bulgaria: Increase of generation by 1098 MW (+12.4% of total generation)
4. Croatia: Decrease of generation by 134 MW (-5.3% of total generation)
5. Greece: No significant change
6. Hungary: No significant change
7. Kosovo: No significant change
8. Macedonia: Decrease of generation by 94 MW (-4.3% of total generation)
9. Montenegro: Increase of generation by 76 MW (+12.1% of total generation)
10. Romania: Increase of generation by 120 MW (+0.7% of total generation)
11. Serbia: Increase of generation by 796 MW (+12.3% of total generation)
12. Slovenia: No significant change

Because of changes in generation, changes in initial exchange per country are also introduced. On Figure 170, comparison of total generation per country in Alternative Case and Base Case Highest Consumption regime is shown.

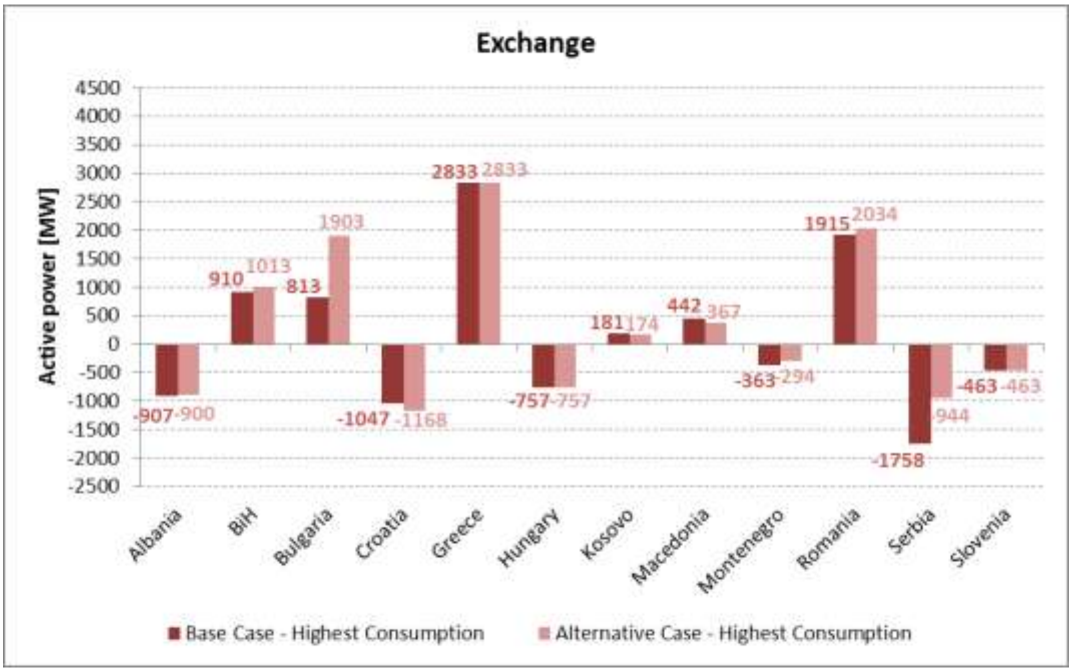



*Figure 170: Total exchange per country for Alternative Case and Base Case Highest Consumption regime*

For Highest Consumption regime, changes in total exchange per country are following:

1. Albania: No significant change
2. Bosnia and Herzegovina: Increase of export by 103 MW
3. Bulgaria: Increase of export by 1090 MW
4. Croatia: Increase of import by 121 MW
5. Greece: No significant change
6. Hungary: No significant change
7. Kosovo: No significant change
8. Macedonia: Decrease of export by 75 MW
9. Montenegro: Decrease of import by 69 MW
10. Romania: Increase of export by 120 MW
11. Serbia: Decrease of import by 814 MW
12. Slovenia: No significant change

By comparing changes in total generation and total exchange, it can be seen that additional market coupling has positive effects for BiH, Bulgaria, Montenegro, Romania and Serbia, where increase of generation leads to increase of total export, i.e. decrease of total import. For Croatia and Macedonia, additional coupling introduces decrease of generation which leads to increase of import and decrease of export, respectively. For Greece, Hungary, Kosovo and Slovenia additional market coupling between SEE and Italy does not introduce significant changes in generation. For Albania, increase of generation has no effect on total export as additional generation is used for covering additional power losses introduced by increased power flows across Albanian transmission network.

Load flow analysis results, obtained for Alternative Case - Highest Consumption regime, show significant differences in total cross-border exchange between aggregated physical flows and market based program cross-border flows. Aggregated program exchanges as a result of the market study are shown on Figure 171, while aggregated physical exchanges among analyzed countries are presented on Figure 172.

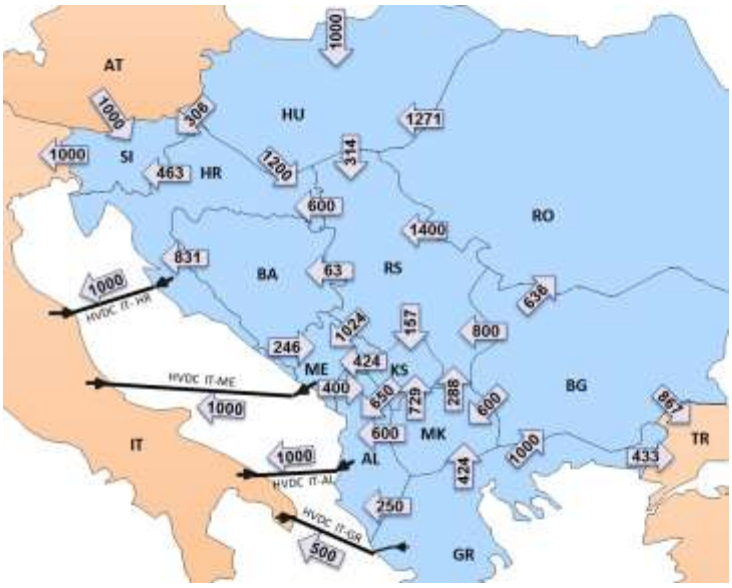



*Figure 171: Aggregated program exchanges in Alternative Case scenario, Highest Consumption regime*

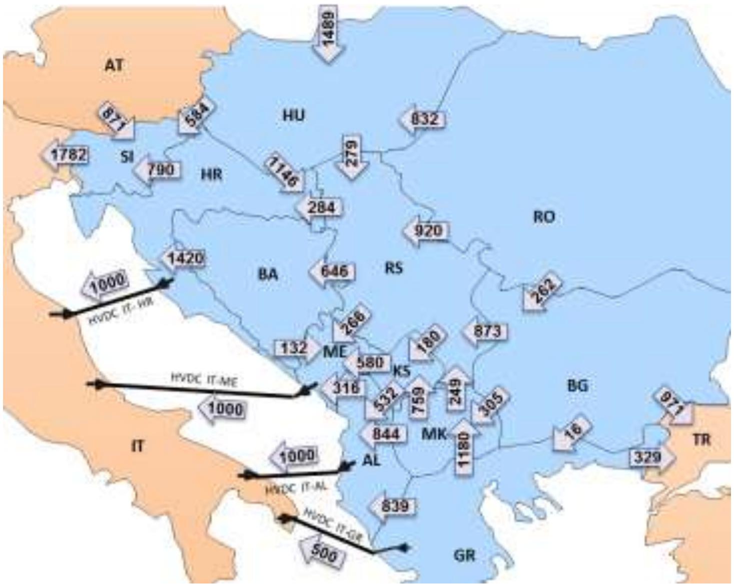



*Figure 172: Aggregated border flows in area of SEE in Alternative Case scenario, Highest Consumption regime*

From previous figures, it can be seen that aggregated program exchanges are different from aggregated physical cross-border flows. From Figure 172 it can be seen that largest cross-border power flows in the region of interest are registered from Bosnia and Herzegovina to Croatia and from Hungary to Croatia. These flows are mainly the consequence of operation of HVDC between Croatia and Italy. Significant cross-border flows are also registered in directions from Romania to Serbia and from Bulgaria to Serbia, which are result of high exports from Romania and Bulgaria. Larger flows are also from Macedonia to Albania and from Greece to Albania, and they are the consequence of consequence of operation of HVDC between Albania and Italy.

For Alternative Case – Highest Consumption regime, there were no transmission network elements in the region of interest which are overloaded in base case topology. Voltage levels for this regime were within permitted ranges.

The contour voltage diagram of the analyzed network of interest is shown in Figure 173.

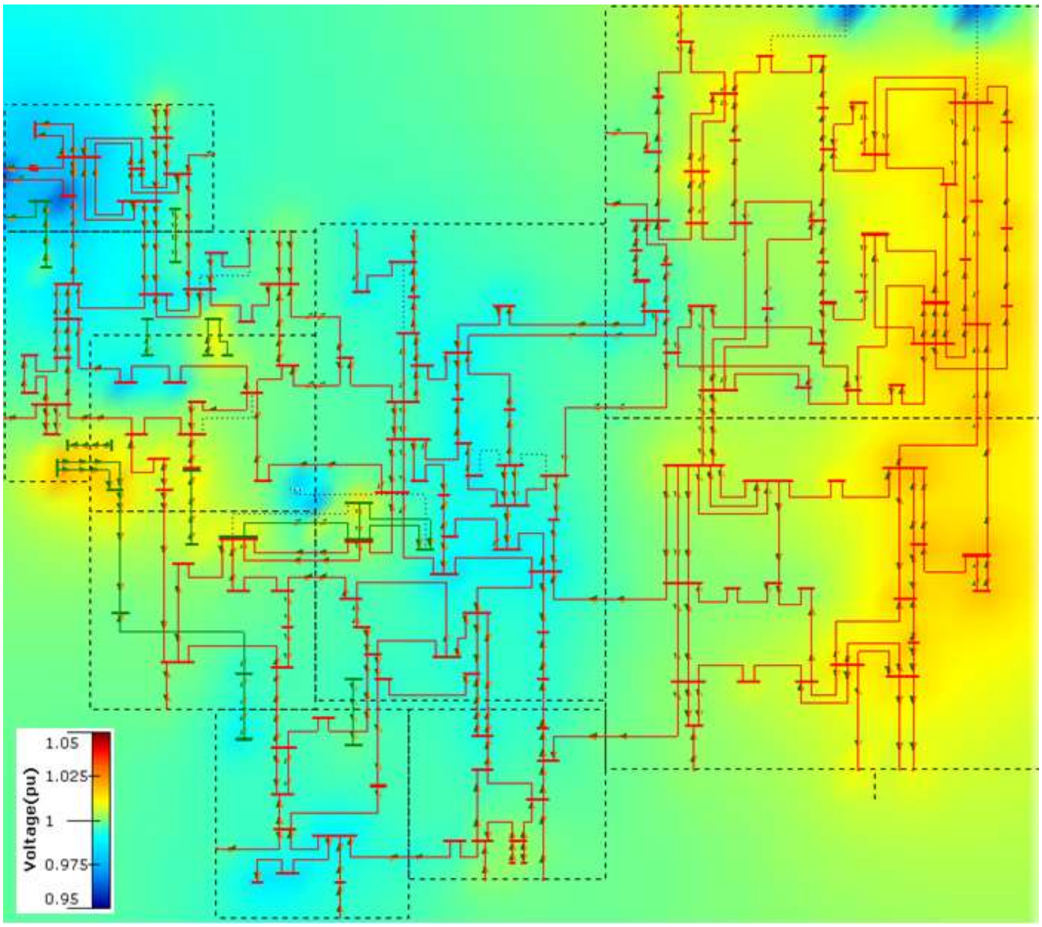



*Figure 173: Voltage profile diagram for the network of interest for the alternative case scenario, highest consumption*

By compering aggregated physical cross-border flows for Base Case (Figure 154) and Alternative Case (Figure 172) for Highest Consumption regime influence of additional market coupling with two new HVDC links can be analyzed. On Figure 174, differences in physical active power flows between Base Case and Alternative Case for Highest consumption regime are shown. Following figure shows absolute changes in total power flows across borders which emerge after putting into operation two new HVDC links. Green arrows indicate that the direction of the flow in Alternative Case is the same as in Base Case. Red arrows indicate that there has been change in direction in Alternative Case when compared to Base Case. Positive value inside the arrow indicates that there has been an increase in power flows while negative value indicated that power flows decreased in Alternative Case when compared to Base Case. For example, total power flow in Base Case between Bosnia and Herzegovina and Croatia was 597 MW, while in Alternative Case the total power flow increased to 1420 MW in same direction, and there for the absolute change (Alternative Case – Base Case) was 823 MW in same direction from Bosnia and Herzegovina towards Croatia and thus the green arrow. On the other hand, total power flow in Base Case between Bulgaria and Greece was 315 MW in direction from Greece to Bulgaria (-315 MW in direction Bulgaria to Greece), while in Alternative Case to direction of the flow changed from

Bulgaria to Greece to 16 MW. Absolute change is now 16 MW – (-315 MW) = 331 MW in direction Bulgaria to Greece. Red arrow indicated that there has been a change in direction in Alternative Case when compared to Base Case.

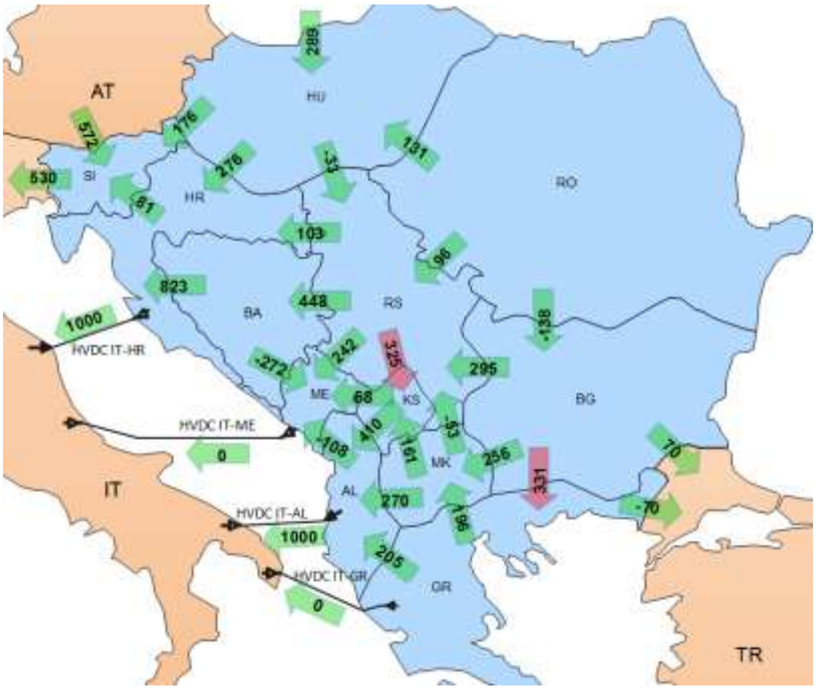



*Figure 174: Changes in physical power flows introduces by two additional HVDC links in Highest Consumption regime*

From previous figure changes in power flows which are consequence of additional market coupling via two new HVDC links HR–IT and AL–IT can be seen. Biggest increase in power flows is noticed in total physical exchange between Bosnia and Herzegovina and Croatia, while significant change is also noticed from Serbia to Bosnia and Herzegovina and from Kosovo to Albania.

Due to increased power flows caused by new HVDC links towards Italy, loading of transmission network elements has generally increased. On Figure 175 histogram of loadings for Base Case and Alternative Case in Highest Consumption regime is show. From shown figure, it can be seen that number of highly loaded elements is higher in Alternative Case, while number of lightly loaded elements is higher in Base Case.

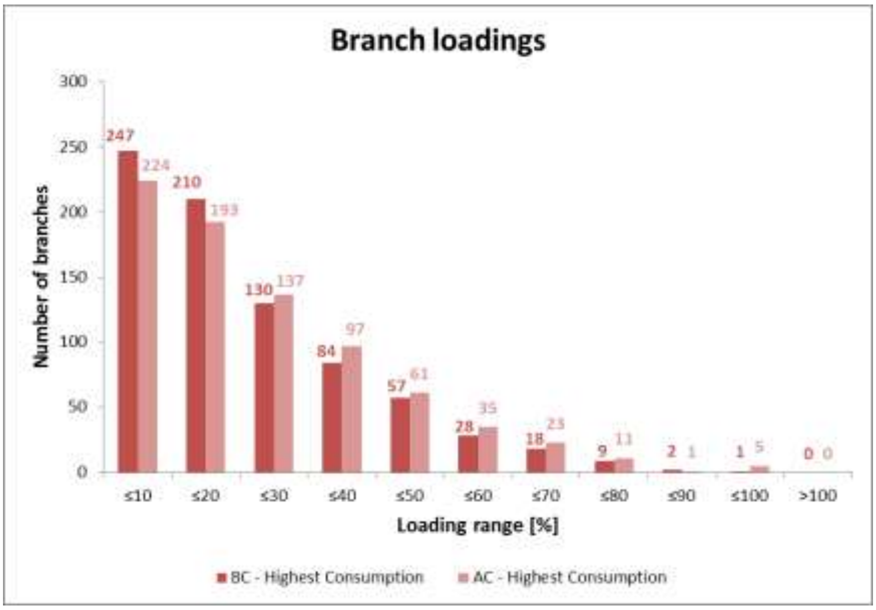



*Figure 175: Element loadings for Base Case and Alternative Case Highest Consumption regime*

Due to increased power flows in Alternative Case, increase of total power losses per country is also registered. On Figure 176, changes in losses per country are shown for cases with two HVDC links (Base Case) and with four HVDC links (Alternative Case) between SEE and Italy. Because of additional power flows in each country introduced by two new HVDC links, increase in total power losses is noticed.

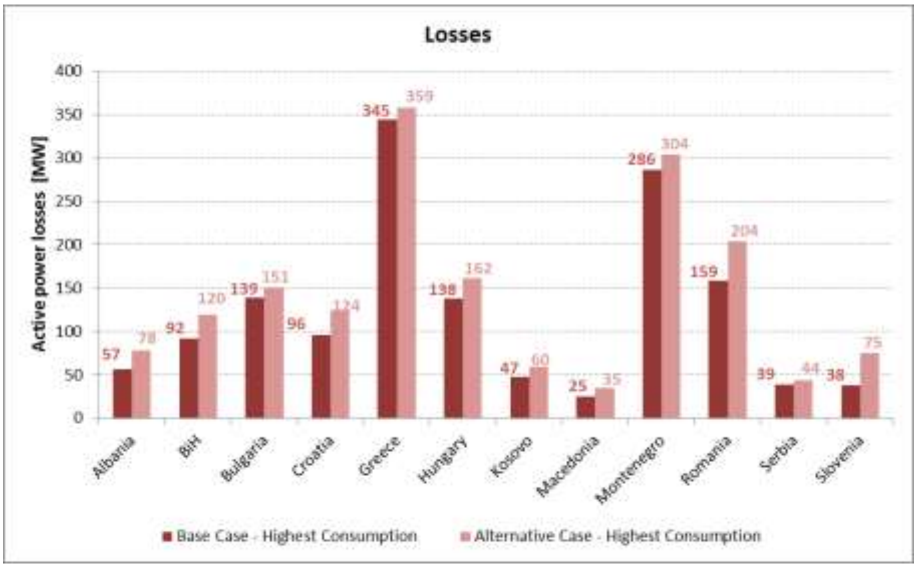



*Figure 176: Losses comparison for Base Case and Alternative Case in Highest Consumption regime*

#### 7.4.1.2 Contingency (n-1) analysis

In contingency analysis conducted for this regime, transmission network in SEE region, starting from 220 kV and above, was subjected to outages of transmission lines of 750 kV, 400 kV and 220 kV voltage levels, as well as to outages of transformers 750/x kV, 400/x kV and 220/x kV. Overloading of 220 kV OHL Zakucac (HR) – Jablanica (BA) and 220 kV Zakucac (HR) – HVRBOR21 (HR) was reported for outage of 400 kV OHL Mostar (BA) – Konjsko (HR), as well as for outage of 220 kV OHL Zakucac (HR) – Konjsko (HR). Besides this, several overloadings of transformers in were also reported, but these are considered to be of local importance.

When compared to Base Case Highest Consumption regime contingency (n-1) analysis results, only significant differences in Alternative Case High Consumption regime contingency (n-1) analysis results are for before mentioned overloadings of 220 kV network in Croatia. Reason for new overloadings in Alternative Case is increased power flows caused by new HVDC link HR-IT.

#### 7.4.1.3 Sensitivity (n-1) analysis

As for Base Case regimes, additional sensitivity (n-1) analysis was conducted for Alternative Case regimes. Planned project which are on identified transmission corridors, formed in new marked coupling conditions, were additionally evaluated by TOOT methodology by assessing its influence on overall (n-1) security criteria.

Taking out of consideration project new 400 kV OHL Pancevo (RS) – Resita (RO), caused congestion (overloadings) on remaining interconnection between Romania and Serbia in normal regime without this project. Contingency analysis for case without this project has reported large number of overloadings in 400 kV network of eastern Serbia, as well as in 220 kV network in western Romania. When compared to Base Case sensitivity analysis for this project, it can be seen that in Alternative Case overloadings would emerge even in full network topology, while in case of outages, number of overloadings would also increase.

When project new 400 kV OHL Banja Luka (BA) – Lika (HR) is taken out of operation, there are no new overloadings in addition to already reported ones in regular (n-1) contingency analysis. There are no differences when compared to Base Case conclusions regarding this project.

Taking out of consideration project new 400 kV OHL Bitola (MK) – Elbasan (AL), introduces new overloading (in addition to already reported ones) of 400 kV OHL Skopje 1 (MK)– Skopje 4 (MK) for the cases of outage of 400 kV Elbasan (AL) – Zemblak (AL) and 400 kV Karida (GR) – Zemblak (AL). Overloading of this line is the main difference between Base Case sensitivity analyses for project new 400 kV OHL Bitola (MK) – Elbasan (AL).

When new 400 kV interconnections RS-BA-ME are taken out of consideration, there are no new overloadings in addition to already reported ones in regular (n-1) contingency analysis. There are no differences when compared to Base Case conclusions regarding this project.

## 7.4.2 Alternative Case Regime 2 - Highest RES penetration

### 7.4.2.1 Load flow and voltage profile analysis

Table 52 shows total production, consumption and exchange per country for Alternative Case Highest RES penetration regime, which were results of previously conducted market analyses.

*Table 52: Area summary for Base Case Highest RES penetration regime*

| Alternative Case - Highest RES penetration regime | Generation (MW) | Consumption (MW) | Exchange (MW) |
|---|---|---|---|
| Albania | 706 | 1606 | -900 |
| BiH | 2442 | 2302 | 139 |
| Bulgaria | 6448 | 5243 | 1206 |
| Croatia | 2301 | 2891 | -589 |
| Greece | 10018 | 8624 | 1394 |
| Hungary | 3631 | 5371 | -1740 |
| Kosovo | 1715 | 1347 | 368 |
| Macedonia | 1043 | 1532 | -489 |
| Montenegro | 766 | 758 | 8 |
| Romania | 11663 | 7363 | 4300 |
| Serbia | 6253 | 6163 | 91 |
| Slovenia | 1789 | 1777 | 12 |

By comparing generation and exchange patter for Base Case and Alternative Case, influence of two additional HVDC links between SEE region and Italy can be analyzed for specific regime. On Figure 177, comparison of total generation per country in Alternative Case and Base Case Highest RES penetration regime is presented.

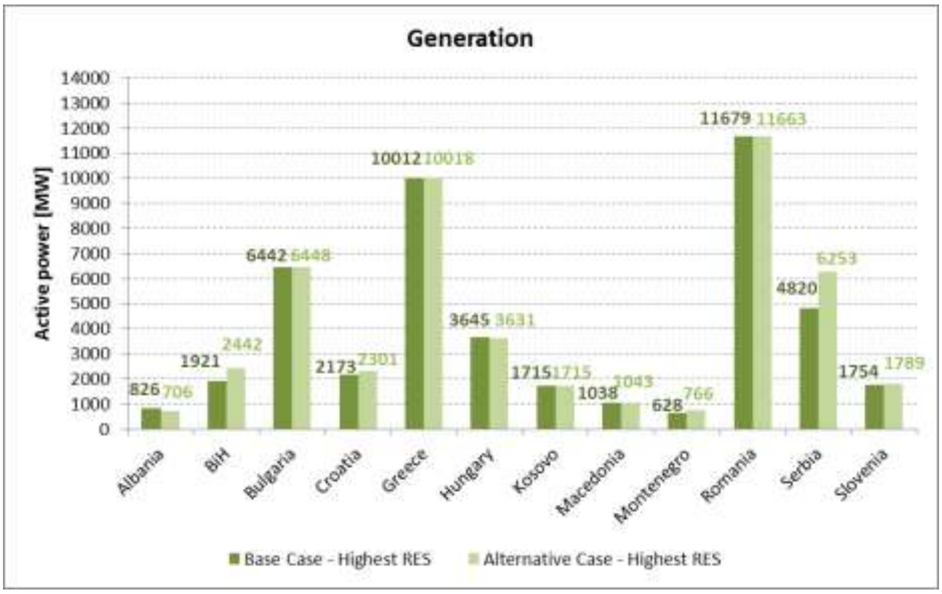



*Figure 177: Generation per country for Alternative Case and Base Case Highest RES penetration regime*

From previous figure, it can be seen that with two additional HVDCs HR-IT and AL-IT, as in previous analyzed regime, new electricity market conditions are such that some countries in SEE region change their total generation. For Highest RES penetration regime, changes in total generation per country are following:

1. Albania: Decrease of generation by 121 MW (-17% of total generation)
2. Bosnia and Herzegovina: Increase of generation by 521 MW (+21% of total generation)
3. Bulgaria: No significant change
4. Croatia: Increase of generation by 128 MW (+6% of total generation)
5. Greece: No significant change
6. Hungary: No significant change
7. Kosovo: No significant change
8. Macedonia: No significant change
9. Montenegro: Increase of generation by 138 MW (+18% of total generation)
10. Romania: No significant change
11. Serbia: Increase of generation by 1434 MW (+23% of total generation)
12. Slovenia: Increase of generation by 35 MW (+2% of total generation)

Due to changes in generation, changes in initial exchange per country are also introduced. On Figure 178, comparison of total generation per country in Alternative Case and Base Case Highest RES penetration regime is shown.

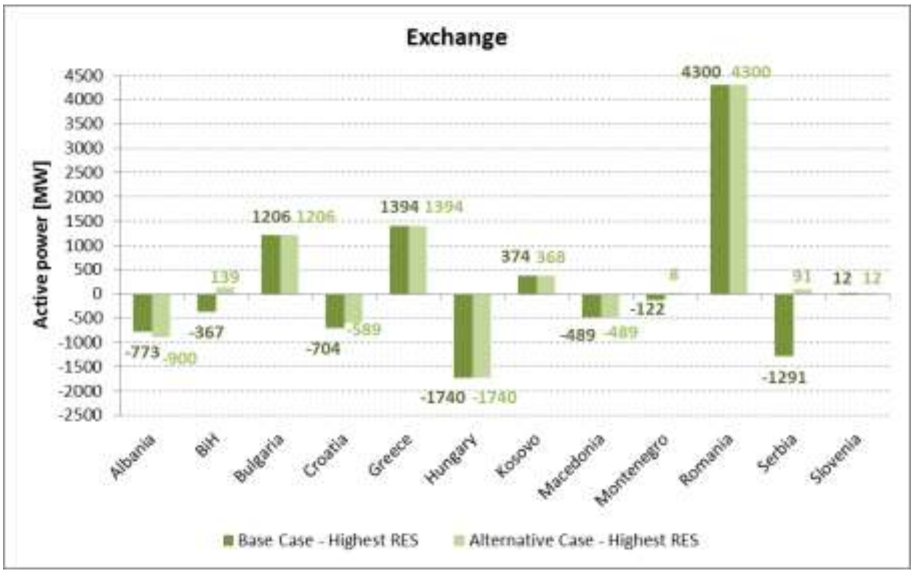



*Figure 178: Total exchange per country for Alternative Case and Base Case Highest RES penetration regime*

For Highest RES penetration regime, changes in total exchange per country are following:

1. Albania: Increase of import by 127 MW
2. Bosnia and Herzegovina: Decrease of import by 506 MW
3. Bulgaria: No significant change
4. Croatia: Decrease of import 115 MW
5. Greece: No significant change
6. Hungary: No significant change
7. Kosovo: No significant change
8. Macedonia: No significant change
9. Montenegro: Decrease of import by 130 MW
10. Romania: No significant change
11. Serbia: Decrease of import by 1382 MW
12. Slovenia: No significant change

By comparing changes in total generation and total exchange, it can be seen that the most positive effects are noticed for Bosnia and Herzegovina and Serbia, because these countries, after being importers become exporters of electric energy. Positive effects are also noticed for Croatia and Montenegro as they decrease their imports due to additional market coupling. Opposite effect is noticed for Albania as this country additionally increases its import by 127 MW. For other countries, there are no significant changes in total generation and total exchange.

Load flow analysis results, obtained for Alternative Case - Highest RES penetration regime, show differences in total cross-border exchange between aggregated physical flows and market based program cross-border flows. Aggregated program exchanges as a result of the market study are shown on Figure 179, while aggregated physical exchanges among analyzed countries are presented on Figure 180.

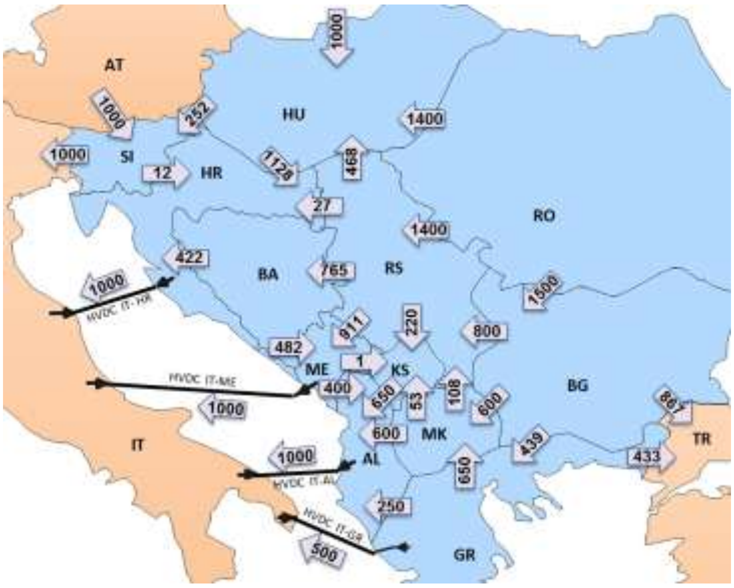



*Figure 179: Aggregated program exchanges in Alternative Case scenario, Highest RES regime*

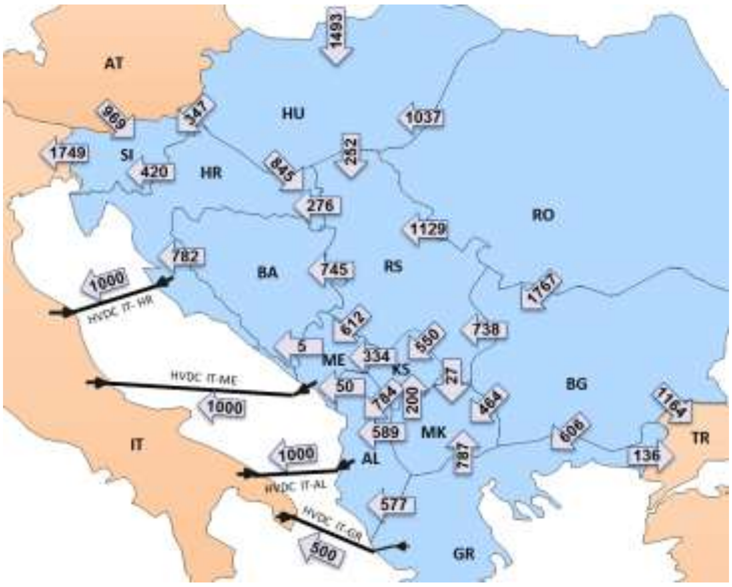



*Figure 180: Aggregated border flows in area of SEE in Alternative Case scenario, Highest RES regime*

It can be noticed that difference between exchanges which are result of the load flow calculation and result of market analyzes, although not so big as in previous regimes, are again consequence of loop flows. Many aggregated physical exchanges are very similar to program exchanges (for example, exchange from Romania to Serbia, from Romania to Bulgaria and from Serbia to B&H), while on the other hand, in several cases physical flows are with different direction from program interchanges (for example, from Croatia to Slovenia, from Montenegro to Albania and from Hungary to Serbia). Larges aggregated physical cross-border flows are registered in directions from Romania to Serbia, from Romania to Bulgaria and from Romani to Hungary. Significant flows are also registered from Hungary to Croatia and from Greece to Macedonia. Reason for such high flows on mentioned borders are due to large exports of Romania and Greece in analyzed regime.

For Alternative Case – Highest RES penetration regime, there were no transmission network elements in the region of interest which are overloaded in base case topology. Voltage levels for this regime were within permitted ranges.

The voltage profile diagram of the analyzed network of interest is shown in Figure 181.

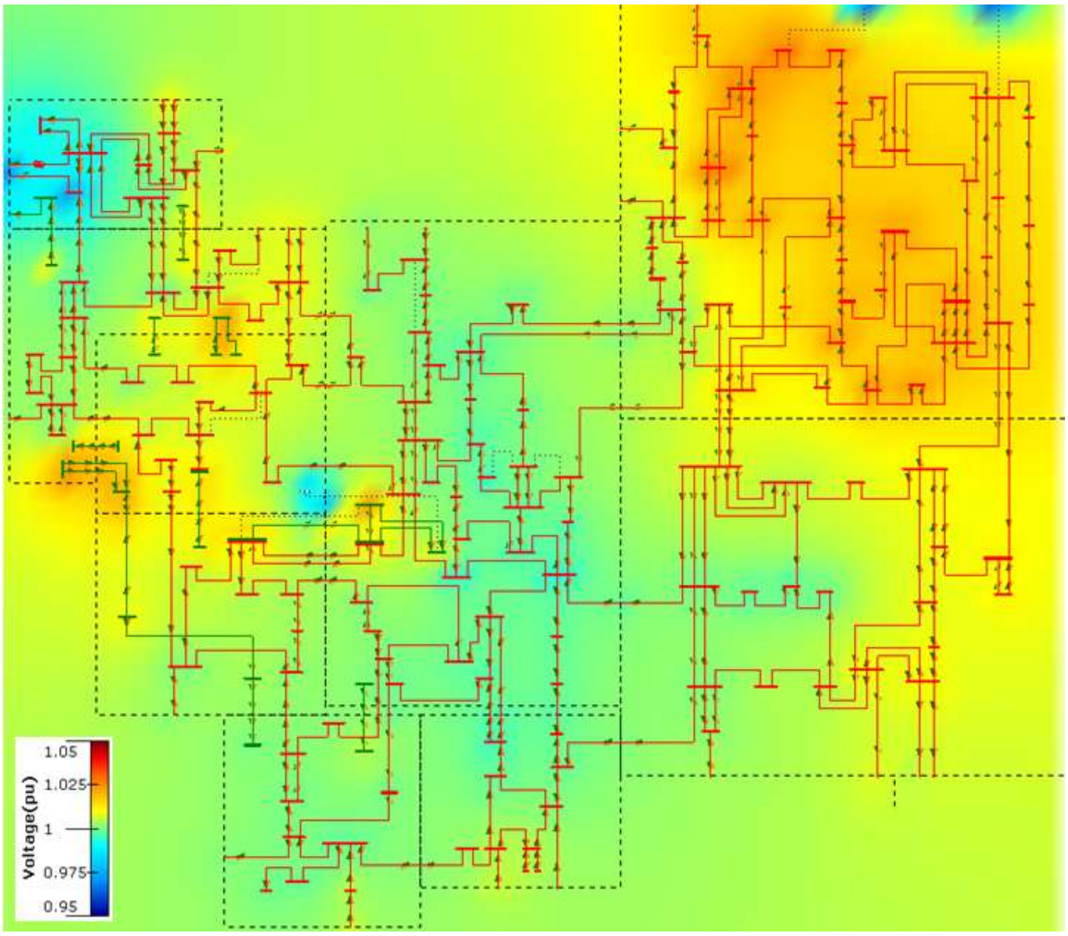


*Figure 181: Voltage profile diagram for the network of interest for the alternative case scenario, highest RES penetration*

As for previous analyzed regime, comparison of Base Case and Alternative Case for Highest RES penetration regime is analyzed in order to properly assess the influence of additional market coupling between SEE region and Italy introduced by two new HVDCs HR-IT and AL-IT.

On Figure 182, differences in physical active power flows between Base Case (Figure 161) and Alternative Case (Figure 180) for Highest RES penetration regime are shown. Following figure shows absolute changes in total power flows across borders which emerge after putting into operation two new HVDC links. Explanation about the color of the arrows and values of the flows are already given for Highest Consumption regime (chapter 7.4.1.1).

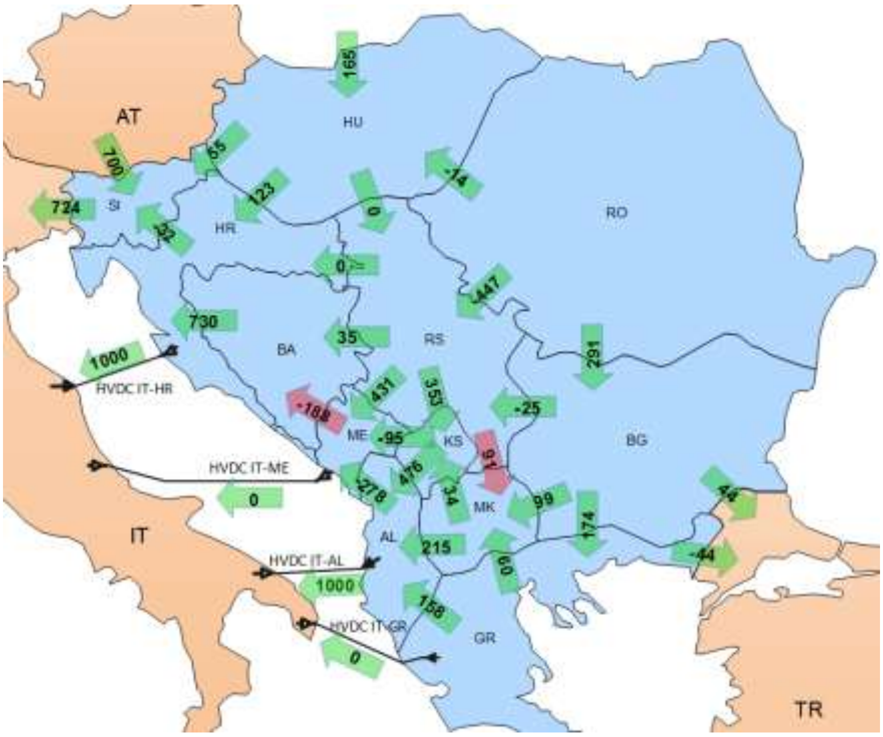



*Figure 182: Changes in physical power flows introduces by two additional HVDC links in Highest RES penetration regime*

As for Highest Consumption regime, biggest change in total power flows is noticed between Bosnia and Herzegovina and Croatia. Also, large increase of power flows is noticed between Serbia and Montenegro, Kosovo and Albania, Serbia and Kosovo, while decrease of power flows is noticed between Romania and Serbia.

Due to increased power flows caused by new HVDC links towards Italy, loading of transmission network elements has generally increased. It can be noticed from Figure 183 that because of additional power flows from SEE to Italy via two new HVDC connections, loading of elements in generally higher.

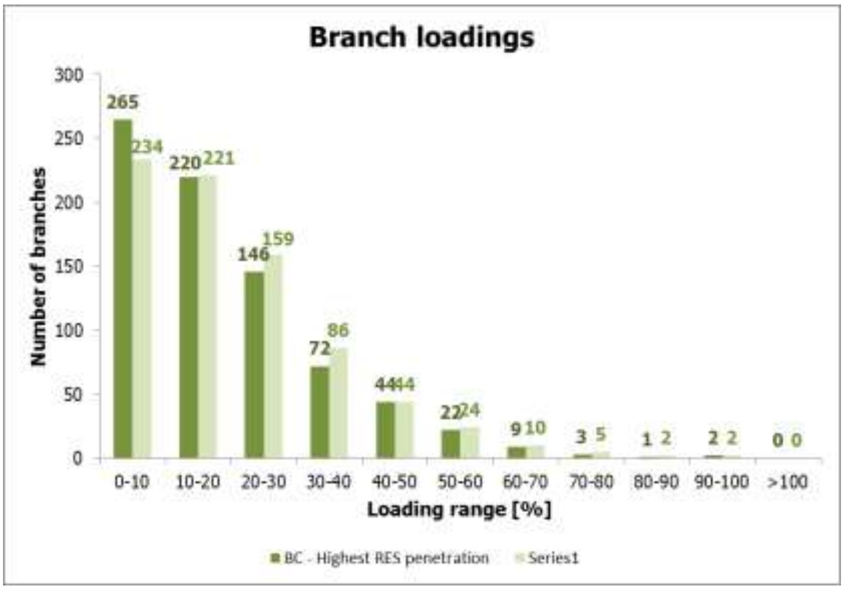



*Figure 183: Element loadings for Base Case and Alternative Case Highest RES penetration regime*

On following figure, changes in losses per country are shown for cases with two HVDC links (Base Case) and with four HVDC links (Alternative Case) between SEE and Italy. Because of additional power flows, each country faces increase in power losses, except Hungary for which slightly decrease of power losses in noticed.

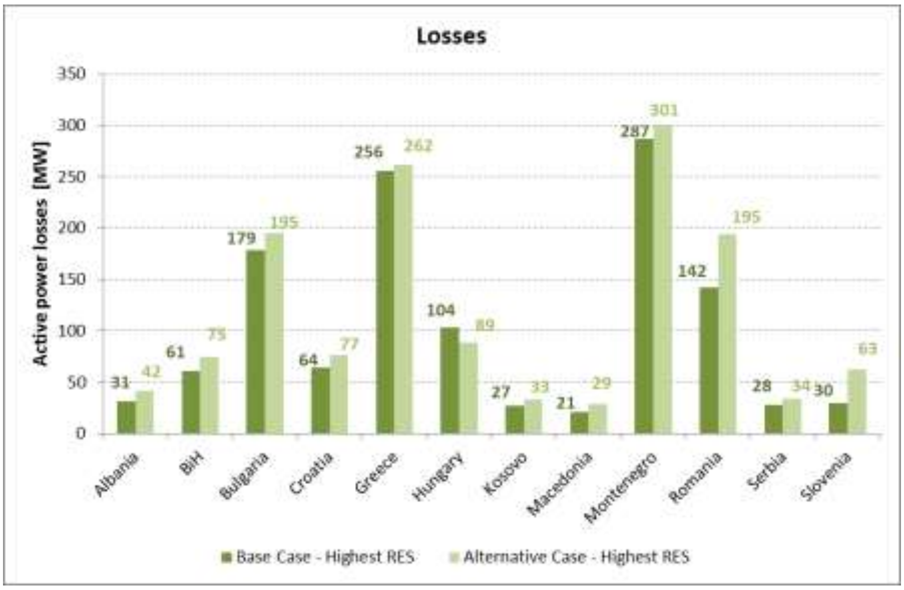



*Figure 184: Losses comparison for Base Case and Alternative Case in Highest RES penetration regime*

#### 7.4.2.2 Contingency (n-1) analysis

Contingency analysis results for Alternative Case Highest RES penetration regime have shown that there are no overloadings of interest in transmission network of SEE region. This is different to findings made for Base Case Highest RES penetration regime, for which there has been congestion on interconnection line between Serbia and Romania. Reason for better results in Alternative Case is that when compared to Base Case, total power flows in direction from Romania to Serbia have decreased for about 450 MW while there has been an increase in total flows from Romania to Bulgaria (Figure 182). With this load flow pattern, transmission network in eastern Serbia, which has been a bottleneck in Base Case Highest RES penetration regime, is now less loaded and not overloaded in contingency cases.

#### 7.4.2.3 Sensitivity (n-1) analysis

Planned project which are on identified transmission corridors, formed in new marked coupling conditions in Alternative Case Highest RES penetration regime, were additionally evaluated by TOOT methodology by assessing its influence on overall (n-1) security criteria.

It is known that project new 400 kV interconnection between Romania and Serbia assumes not only the new 400 kV OHL Pancevo (RS) – Resita (RO), but also several reinforcements and upgrades of 220 kV to 400 kV voltage level in Romania. When this whole project is not taken into consideration in (n-1) contingency analysis, 400 kV transmission network in eastern Serbia becomes overloaded even in base case. In (n-1) situations, even larger number of transmission network elements in eastern Serbia and western Romania is reported as overloaded. Due to additional coupling with Italian market via two new HVDC links, increase of RES production in eastern parts of the SEE region increases the flows in E-W direction making even larger congestion on Serbia-Romania border.

Project new 400 kV OHL Banja Luka (BA) – Lika (HR), does not introduce new overloadings in rest of the transmission network, when it is not considered in (n-1) security assessment.

Not considering projects new 400 kV Banja Luka (BA) – Lika (HR), new 400 kV Bitola (MK) – Elbasan (AL) and new 400 kV interconnections RS-BA-ME, did not introduce any additional overloadings in the transmission network of interest.

## 7.4.3 Alternative Case Regime 3 – Lowest consumption

### 7.4.3.1 Load flow and voltage profile analysis

Table 53 shows total production, consumption and exchange per country for Alternative Case Lowest Consumption regime, which were results of previously conducted market analyses.

*Table 53: Area summary of analyzed region for Alternative Case Lowest Consumption regime*

| Base Case – Lowest Consumption regime | Generation (MW) | Consumption (MW) | Exchange (MW) |
|---|---|---|---|
| Albania | 575 | 693 | -118 |
| BiH | 126 | 1264 | -1138 |
| Bulgaria | 3462 | 2976 | 486 |
| Croatia | 942 | 1542 | -600 |
| Greece | 2281 | 4368 | -2087 |
| Hungary | 1956 | 3567 | -1611 |
| Kosovo | 1683 | 394 | 1289 |
| Macedonia | 1230 | 733 | 497 |
| Montenegro | 81 | 368 | -287 |
| Romania | 7241 | 5063 | 2178 |
| Serbia | 3508 | 2869 | 639 |
| Slovenia | 1935 | 1194 | 741 |

By comparing generation and exchange patter for Base Case and Alternative Case, influence of two additional HVDC links between SEE region and Italy can be analyzed for specific regime. On Figure 185, comparison of total generation per country in Alternative Case and Base Case Lowest Consumption regime is presented.

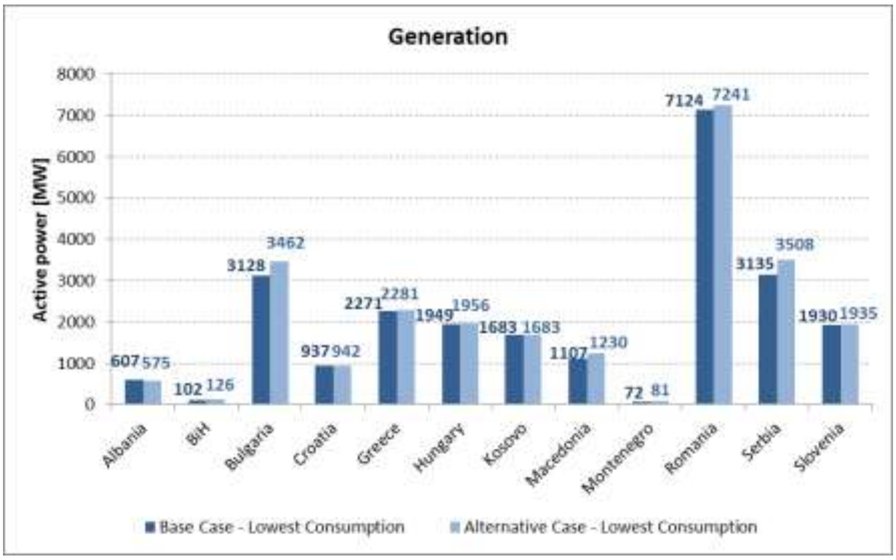



*Figure 185: Generation per country for Alternative Case and Base Case Lowest Consumption regime*

From previous figure, it can be seen that with two additional HVDCs HR-IT and AL-IT, consequential coupling introduces such electricity market conditions that some countries in SEE region change their total generation. For Lowest Consumption regime, changes in total generation per country are following:

1. Albania: Decrease of generation by 31 MW (-5% of total generation)
2. Bosnia and Herzegovina: Increase of generation by 23 MW (+23% of total generation)
3. Bulgaria: Increase of generation by 334 MW (+11% of total generation)
4. Croatia: No significant change
5. Greece: No significant change
6. Hungary: No significant change
7. Kosovo: No significant change
8. Macedonia: Increase of generation by 132 MW (+11% of total generation)
9. Montenegro: Increase of generation by 9 MW (+12% of total generation)
10. Romania: Increase of generation by 117 MW (+2% of total generation)
11. Serbia: Increase of generation by 373 MW (+12% of total generation)
12. Slovenia: No significant change

Because of changes in generation, changes in initial exchange per country are also introduced. On Figure 186, comparison of total generation per country in Alternative Case and Base Case Lowest Consumption regime is shown.

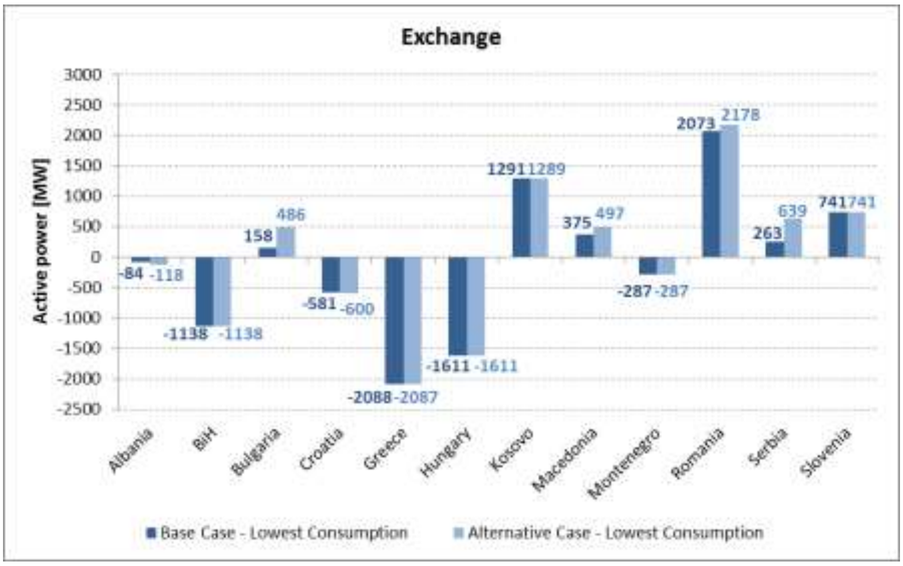



*Figure 186: Total exchange per country for Alternative Case and Base Case Lowest Consumption regime*

For Lowest Consumption regime, changes in total exchange per country are following:

1. Albania: Increase of import by 34 MW
2. Bosnia and Herzegovina: No significant changes
3. Bulgaria: Increase of export by 328 MW
4. Croatia: Increase of import by 19 MW
5. Greece: No significant change
6. Hungary: No significant change
7. Kosovo: No significant change
8. Macedonia: Increase of export by 122 MW
9. Montenegro: No significant change
10. Romania: Increase of export by 105 MW
11. Serbia: Increase of export by 376 MW
12. Slovenia: No significant change

From previous findings, it can be concluded that additional market coupling in Lowest Consumption regime, introduces positive effects on Bulgaria, Macedonia, Romania and Serbia, as these countries increase their export. Opposite effects are noticed for Albania and Croatia as these countries increase their import in Lowest Consumption regime. Additional coupling has no effect on total exchanges of Greece, Hungary, Kosovo, Montenegro and Slovenia, in Lowest Consumption regime.

As for previous Alternative Case regimes, load flow analysis results for Lowest Consumption regime show differences in total cross-border exchange between aggregated physical flows and market based program cross-border flows. Aggregated program exchanges which are result of the market studies are shown on Figure 187, while aggregated physical exchanges among analyzed countries are presented on Figure 188. As in all previous regimes, there are differences between exchanges as a result of the load flow calculation and estimated exchanges from the market study for the same regimes.

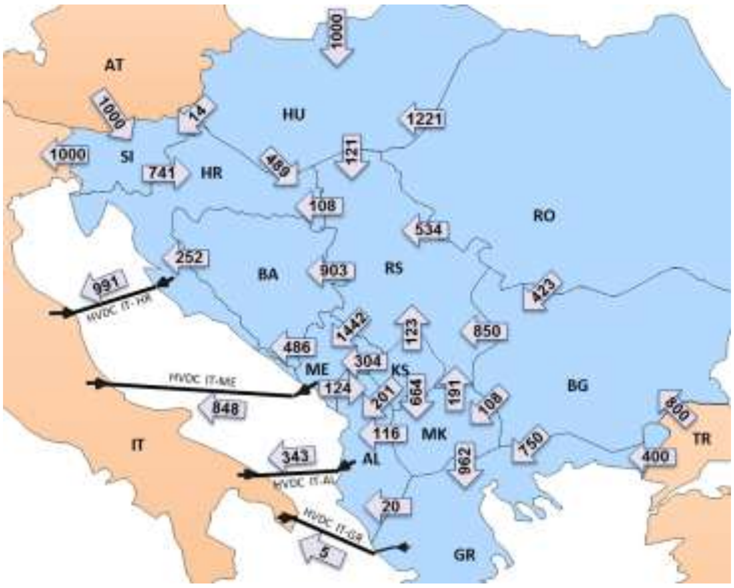



*Figure 187: Aggregated program exchanges in Alternative Case scenario, Lowest Consumption regime*

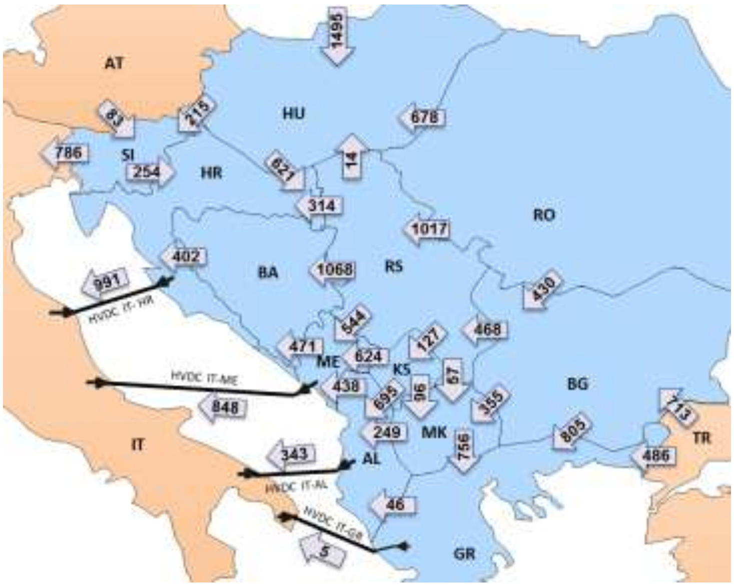



*Figure 188: Aggregated physical exchanges in Alternative Case scenario, Lowest Consumption regime*

When analyzing physical power flows shown on Figure 188, it can be seen that largest aggregated flows in region of interest are registered on interconnection lines between Romania and Serbia and between Serbia and Bosnia and Herzegovina. Significant cross-border flows are also registered from Bulgaria to Greece, from Macedonia to Greece, from Kosovo to Albania and from Kosovo to Montenegro.

Load flow results for Alternative Case – Lowest Consumption regime have shown that there are no overloaded elements in the transmission network of interests. When analyzing loading of elements, 400 kV and 220 kV transmission lines and 400/x kV and 220/x kV transformers were considered, while elements of lower voltage levels were not analyzed in details, as it is taken to be of local importance.

The same as for Base Case - Lowest Consumption regime, it should be pointed out that in order to get a feasible load flow solution for Alternative Case – Lowest Consumption regime, additional measures had to be implemented in order to decrease initial voltage values. Because of low loading, much of the transmission lines initially generated additional reactive power causing voltage values higher than permitted which gave infeasible solution. Because of that, existing shunt reactors were put in operation and many generator units were set to operate in under excitation regime, which corresponds to usual operational practice in analyzed power systems. Implementation of such measures gave feasible load flow solution with voltage levels in permitted operational ranges.

The voltage profile diagram of the analyzed network of interest is shown on Figure 189.

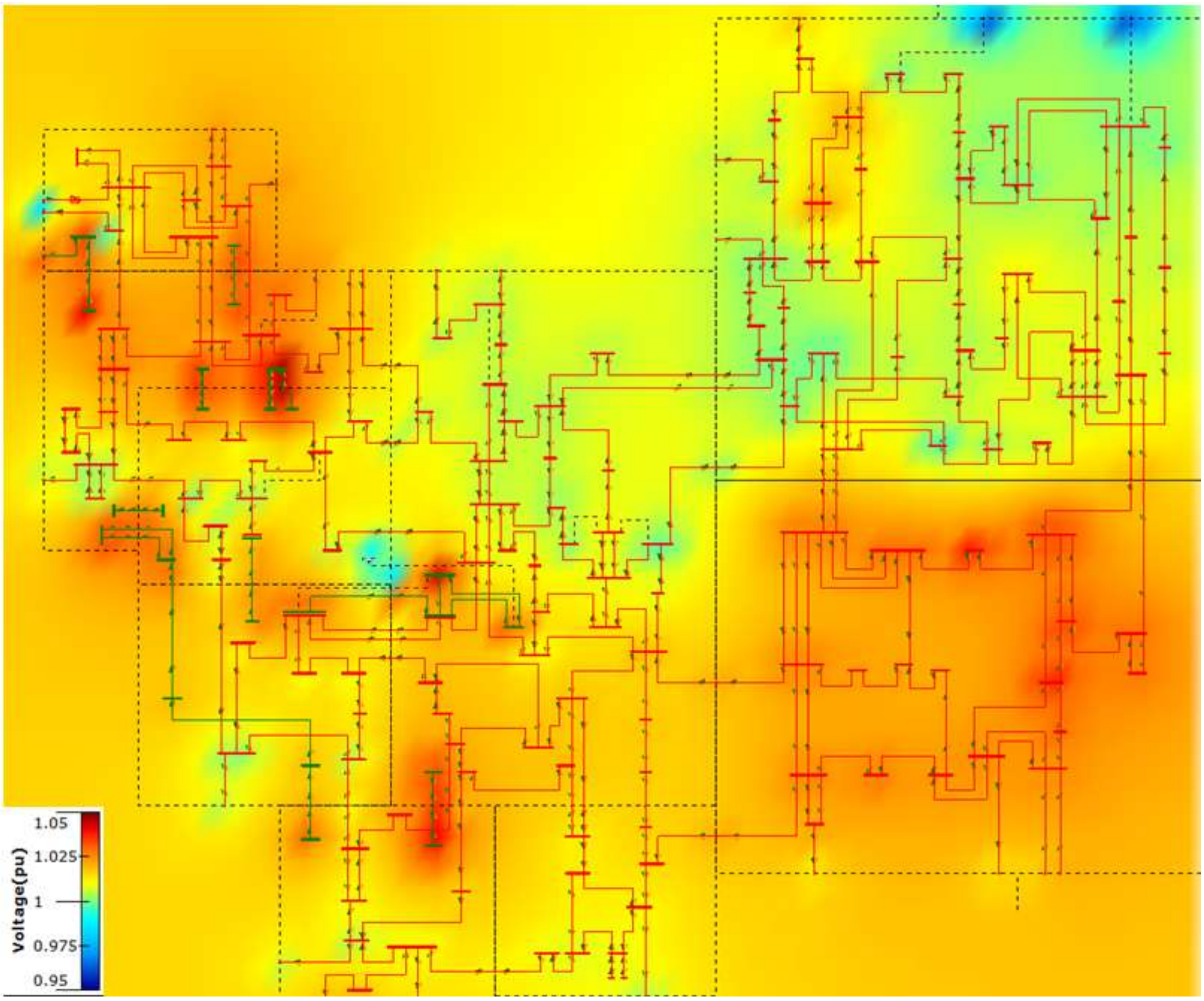



*Figure 189: Voltage profile diagram for the network of interest for the alternative case scenario, lowest consumption regime*

As for previous analyzed regimes, comparison of Base Case and Alternative Case for Lowes Consumption regime is analyzed in order to properly assess the influence of additional market coupling between SEE region and Italy introduced by two new HVDCs HR-IT and AL-IT. On Figure 190, differences in physical active power flows between Base Case and Alternative Case for Lowest Consumption regime are shown. Following figure shows absolute changes in total power flows across borders which emerge after putting into operation two new HVDC links. Explanation about the color of the arrows and values of the flows are already given for Highest Consumption regime (chapter 7.4.1.1).

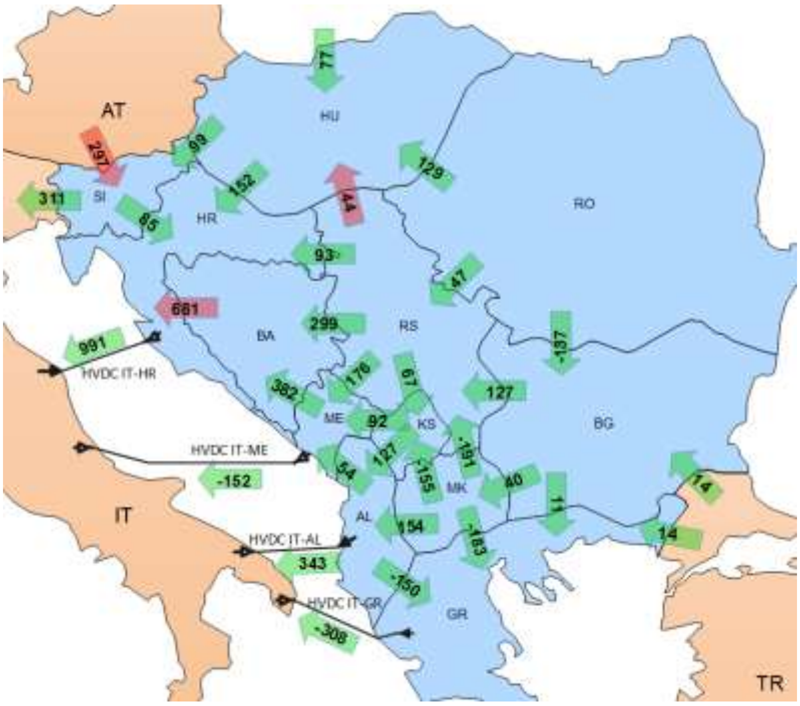



*Figure 190: Changes in physical power flows introduces by two additional HVDC links in Lowest Consumption regime*

As for previous regimes, biggest increase in total power flows is noticed between Bosnia and Herzegovina and Croatia, with additional change in direction in Alternative Case when compared to Base Case. Also, large increase of power flows is noticed from Serbia towards Bosnia and Herzegovina, and from Montenegro towards Bosnia and Herzegovina. It is interested to notice that operation of HVDC links HR-IT and AL-IT in Lowest Consumption regime will decrease the power flows via other two HVDC links, ME-IT and GR-IT.

Due to changes in power flows caused by new HVDC links towards Italy, loading of transmission network elements has generally increased. It can be noticed from Figure 191 that because of additional power flows from SEE to Italy via two new HVDC connections, loading of elements in generally higher but due to low level of consumption, the difference between cases is not that big.

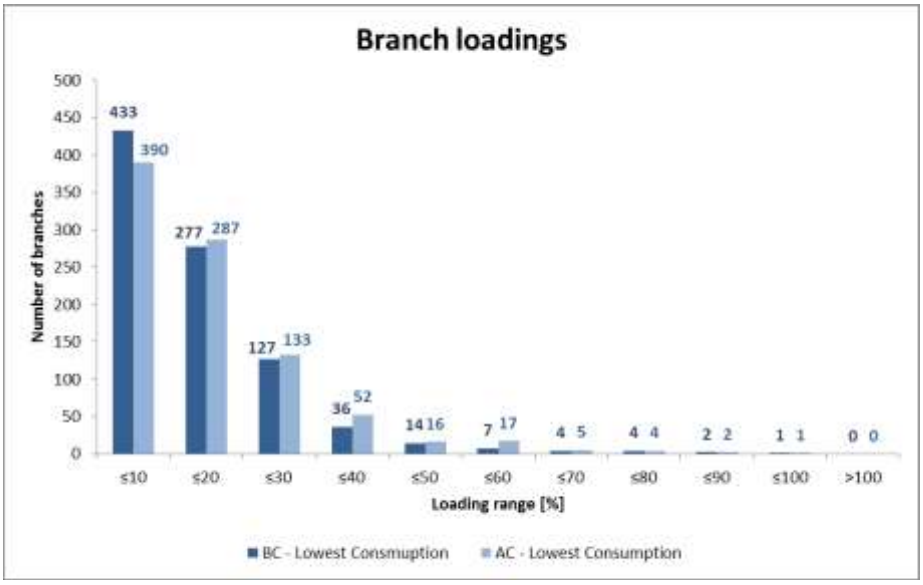



*Figure 191: Element loadings for Base Case and Alternative Case Lowest Consumption regime*

On following figure, changes in losses per country are shown for cases with two HVDC links (Base Case) and with four HVDC links (Alternative Case) between SEE and Italy. Because of additional power flows, each country faces increase in power losses, except Greece for which slightly decrease of power losses in noticed.

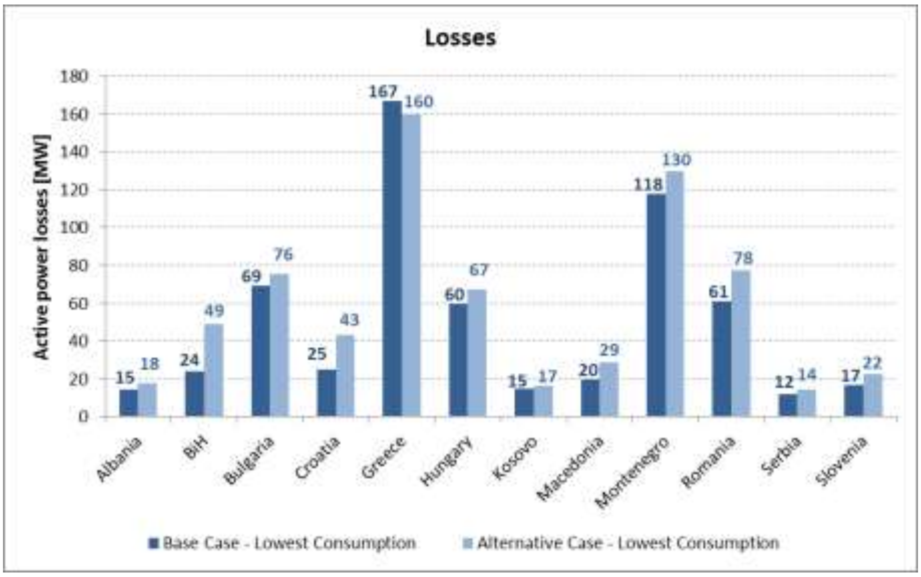



*Figure 192: Losses comparison for Base Case and Alternative Case in Lowest Consumption regime*

#### 7.4.3.2 Contingency (n-1) analysis

The same as for Base Case Lowest Consumption regime, due to much lower levels of total generation and demand per country in Alternative Case, when compared to two previous regimes, transmission network elements are initially much less loaded. Therefore, results of (n-1) contingency analysis have shown that in Alternative Case Lowest Consumption regime, there are no transmission network elements of interest which are overloaded.

#### 7.4.3.3 Sensitivity (n-1) analysis

Planned project which are on identified transmission corridors, formed in new marked coupling conditions in Alternative Case Lowest Consumption regime, were additionally evaluated by TOOT methodology by assessing its influence on overall (n-1) security criteria.

Taking out of consideration project new 400 kV OHL Pancevo (RS) – Resita (RO), caused overloading of 400 kV OHL Djerdap (RS) – Portile de Fier (RO) for several cases of outages. However, if line rating of Serbian part of this interconnection line is increased to match the rating of Romanian part of the line, this element would not be overloaded for previously identified outages.

When projects new 400 kV OHL Banja Luka (BA) – Lika (HR), new 400 kV OHL Bitola (MK) – Elbasan (AL) are not considered in (n-1) contingency analysis, there are no additional overloadings in transmission network of interest.

Taking out of consideration project new 400 kV interconnection RS-BA-ME, caused overloadings of 220 kV OHL Podgorica (ME) – Koplik (AL) and 220 kV OHL Pljevlja (ME) – Bajina Basta (RS) when 400 kV OHL Pec (KS) – Ribarevine (ME) goes out of operation.

### 7.4.4 Alternative Case Regimes - Summary

For all Alternative Case regimes, it can generally be concluded that market coupling in SEE region introduces changes in load flow patterns. Changes in power flows in transmission networks of the SEE region do not lead to overloadings in case when all elements are in operation. In such network topology conditions, voltage levels were in permitted ranges for Highest Consumption and Highest RES penetration regimes. For Lowest Consumption regime, in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initial unfeasibly high values of voltages.

In terms of (n-1) security criteria assessment, Highest Consumption regime is identified as the most critical one for Alternative Case scenario. In this regime, outage of 400 kV OHL Konjsko (HR) – Mostar (BA) and outage of 220 kV Konjsko (HR) – Zakucac (KR) are causing overloading of 220 kV OHL Zakucac (HR) – Jablanica (BA). For other two regimes, Highest RES penetration and Lowest Consumption, transmission networks in SEE region satisfy (n-1) security criteria.

Reported congestion on Croatia-Bosnia border in Highest Consumption regime, is a strong signal that in order to introduce estimated or higher levels of NTCs for target year between these two countries, additional network reinforcement has to be implemented in order to enhance electricity trade and to support higher social welfare (lower overall energy price).

Sensitivity analysis, conducted for several planned project by applying TOOT methodology, has shown that:

- Project 400 kV OHL Pancevo (RS) – Resita (RO) has shown significant influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Banja Luka (BA) – Lika (HR) has shown less influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Bitola (MK) – Elbasan (AL) has shown influence on (n-1) security criteria in Highest Consumption regime.
- Project new 400 kV interconnections RS-BA-ME has shown influence on (n-1) security criteria in Lowest Consumption regime.

# 8 CONCLUDING REMARKS

## 8.1 Market analyses conclusions

This section presents the main findings resulting from the market analyses.

Resulting wholesale prices, which are determined by marginal cost of generation and price on external markets, are comparable to actual market prices (due to input data on fuel costs, generation cost curves, generation investments and demand increase, etc.). In SEE region **wholesale electricity prices are mainly harmonized**, with certain variations (for example in Greece), what presents practically fully integrated SEE electricity market although network congestions are still present in the region.

**Average market price in SEE region is increased by 1.60 €/MWh in Base Case and 3.75 €/MWh in Alternative Case** compared to results of Reference Case which presents current regional interconnections with Italy. Thus, it can be concluded that additional HVDC links to Italy increase wholesale prices in SEE region, but they also increase electricity generation and revenues.

**Total generation in SEE region is increased by 3.35 TWh (0.96%) in Base Case and 8.98 TWh (2.58%) in Alternative Case**, compared to Reference Case scenario. The most significant change occurs in Bosnia and Herzegovina – in Base Case yearly generation is increased by 1.53 TWh compared to Reference Case, while in Alternative Case by 3.51 TWh. Notable increases of electricity generation can be also observed in Bulgaria, Romania and Serbia.

Additional HVDC cables in Base and Alternative Case increase net interchange to Italy. Italy is a net importer of electricity and in Base Case scenario Italy net imports 5,214 GWh more than in Reference, while in Alternative 12,652 GWh more than in Reference Case scenario. At the same time, SEE region becomes a stronger net exporter in Base and Alternative Case. **In Base Case net interchange of SEE region is 3,284 GWh higher than in Reference, while in Alternative it is 8,753 GWh higher than in Reference Case scenario.**

Dominant power exchange directions can be perceived through power transfer values and the occurrence of congestions. Total transfer sums up the absolute values of total yearly import and export, and **Serbia has the highest total transfer in all scenarios,** but transfer decreases in Base and Alternative Case compared to Reference Case. Significant decrease of total transfer is also noticeable in Bosnia and Herzegovina in Base and Alternative Case compared to Reference. Increase of total transfer is expectedly visible in countries with increased interconnection capacities in respective scenarios, i.e. Albania and Croatia in Alternative Case as well as Montenegro and Italy in both Base and Alternative Case. When looking at the power flow in just one direction, generally, **in both Base and Alternative Case the highest power transit in SEE region is from Romania and Bulgaria to neighboring countries. Regarding external markets, the highest power transit is to Italian market** due to high wholesale prices in Italy.

In terms of cross-border flows, **significant congestions can be noticed in both Base and Alternative Case. In Base Case**, congestions occur especially on the **BG-GR, AL-GR, SI-IT borders and HVDC cable ME-IT**, but only in one direction – to Greece and to Italy. Congestions can be also observed on **CE-HU and CE-SI borders**, in the direction from Central Europe. **In Alternative Case** total cross-border congestions are even higher than in Base Case scenario, but are more evenly distributed. Congestions mostly occur on **CE-SI and CE-HU link** in the direction from Central Europe, and on the **BG-GR border** in the direction to Greece, as in the Base Case. In Alternative Case congestions on **RO-RS border** can be also observed, in the direction from Romania to Serbia. Occurrence of congestions on these borders is a market signal for increasing cross-border capacity.

Effect of $CO_2$ emissions prices was evaluated in the additional set of scenarios (Reference, Base and Alternative Case) without Carbon Cost. In all scenarios w/o Carbon Cost electricity generation is expectedly increased. In Base Case total SEE region generation is 14.49 TWh higher and 14.52 TWh in Alternative Case compared to main set of scenarios which include Carbon Cost. Since these scenarios do not include Carbon Cost, cost of generation is lower and thus market prices in SEE region are lower. Average wholesale price in SEE region is 5.60 €/MWh lower in Base Case and 3.84 €/MWh in Alternative Case in scenarios w/o Carbon Cost compared to main set of scenarios.

## 8.2 Network analyses conclusions

In chapter 7, results of load flow analysis, element loading assessment, estimation of losses and contingency (n-1) analysis were shown. This section presents the main findings resulting from the conducted network analyses.

For all Base Case regimes, it can generally be concluded that market coupling in SEE region introduces changes in load flow patterns. Changes in power flows in transmission networks of the SEE region do not lead to overloadings in case when all network elements are in operation. In such network topology conditions, voltage levels were in permitted ranges for Highest Consumption and Highest RES penetration regimes. For Lowest Consumption regime, in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initial unfeasibly high values of voltages.

In terms of (n-1) security criteria assessment, Highest RES penetration regime is identified as the most critical one for Base Case scenario. In this regime, outage of 400 kV OHL Portile de Fier (RO) – Resita (RO) causes overloading of 400 kV OHL Djerdap (RS) – Portile de Fier (RO). For other two regimes, Highest Consumption and Lowest Consumption, transmission networks in SEE region satisfy (n-1) security criteria.

Sensitivity analysis, conducted for several planned project by applying TOOT methodology, has shown that:

- Project 400 kV OHL Pancevo (RS) – Resita (RO) has shown significant influence on (n-1) security criteria, in Highest Consumption and Highest RES penetration regimes.
- Project 400 kV OHL Banja Luka (BA) – Lika (HR) has shown less influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Bitola (MK) – Elbasan (AL) has shown small influence on (n-1) security criteria, in all analyzed regimes.
- Project new 400 kV interconnections RS-BA-ME has shown small influence on (n-1) security criteria, in all analyzed regimes.

For all Alternative Case regimes, it can generally be concluded that market coupling in SEE region introduces changes in load flow patterns. Changes in power flows in transmission networks of the SEE region do not lead to overloadings in case when all elements are in operation. In such network topology conditions, voltage levels were in permitted ranges for Highest Consumption and Highest RES penetration regimes. For Lowest Consumption regime, in order to get a feasible load flow solution, additional measures had to be implemented in order to decrease initial unfeasibly high values of voltages.

In terms of (n-1) security criteria assessment, Highest Consumption regime is identified as the most critical one for Alternative Case scenario. In this regime, outage of 400 kV OHL Konjsko (HR) – Mostar (BA) and outage of 220 kV Konjsko (HR) – Zakucac (KR) are causing overloading of 220 kV OHL Zakucac (HR) – Jablanica (BA). For other two regimes, Highest RES penetration and Lowest Consumption, transmission networks in SEE region satisfy (n-1) security criteria.

Sensitivity analysis, conducted for several planned project by applying TOOT methodology, has shown that:

- Project 400 kV OHL Pancevo (RS) – Resita (RO) has shown significant influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Banja Luka (BA) – Lika (HR) has shown less influence on (n-1) security criteria, in all analyzed regimes.
- Project 400 kV OHL Bitola (MK) – Elbasan (AL) has shown influence on (n-1) security criteria in Highest Consumption regime.
- Project new 400 kV interconnections RS-BA-ME has shown influence on (n-1) security criteria in Lowest Consumption regime.

For previously identified congestions on borders between Romania and Serbia, and between Croatia and Bosnia and Herzegovina, it is recommended that additional infrastructure strengthening is considered in these regions, in order to enhance electricity trade and to support higher social welfare (lower overall energy price).

It is important here to emphasize the conclusion which was made for Low Consumption regime. It was stated previously, that in the process of creation merged models for this regime, due to particularly high values of voltages, feasible solution could not be reached in first attempt. In order to get a feasible solution, i.e. to reach load flow calculation convergence, additional measures had to be implemented. Shunt reactors were put in operation, and some generator units were set to operate in under excitation regime, which decreased the values of voltages to acceptable levels. Previously described problem in minimum loading regime justifies reactive power compensation studies which are ongoing in the region of SEE.

Also, it was shown that market based results gave very different generation footprint in the region when compared to predictions of individual TSOs. Main reasons for such differences are due to the fact that additional market coupling introduced different country balances, different generation schedules than the ones based on individual TSO experience and higher RES penetration per county.

Additional possibility of improvements lies in more precise modeling of Hungarian and Greek power systems in market software tool, as currently market analyzes for these countries as output give only the aggregated generation per fuel type, and not per individual generating units. Also, SECI RTSM load flow models include equivalent power systems of Northern Italy, Austria, Slovakia, part of Ukraine (Burstin Island) and Turkey, which are not considered in market analysis software. As total generation, demand and exchange for these power systems were adjusted according to obtained results for other countries, more accurate load flow pattern could be obtained if these countries were also considered in future market analyzes.

In order to get a better understanding of market coupling influence on individual TSO operation, it is important to proceed with grid and market investigations in order to properly evaluate benefits and consequences of market operation, optimize market performance, properly evaluate overall social welfare and gain more benefits of regional market integration for SEE region.

# TABLE OF FIGURES

# TABLE OF TABLES