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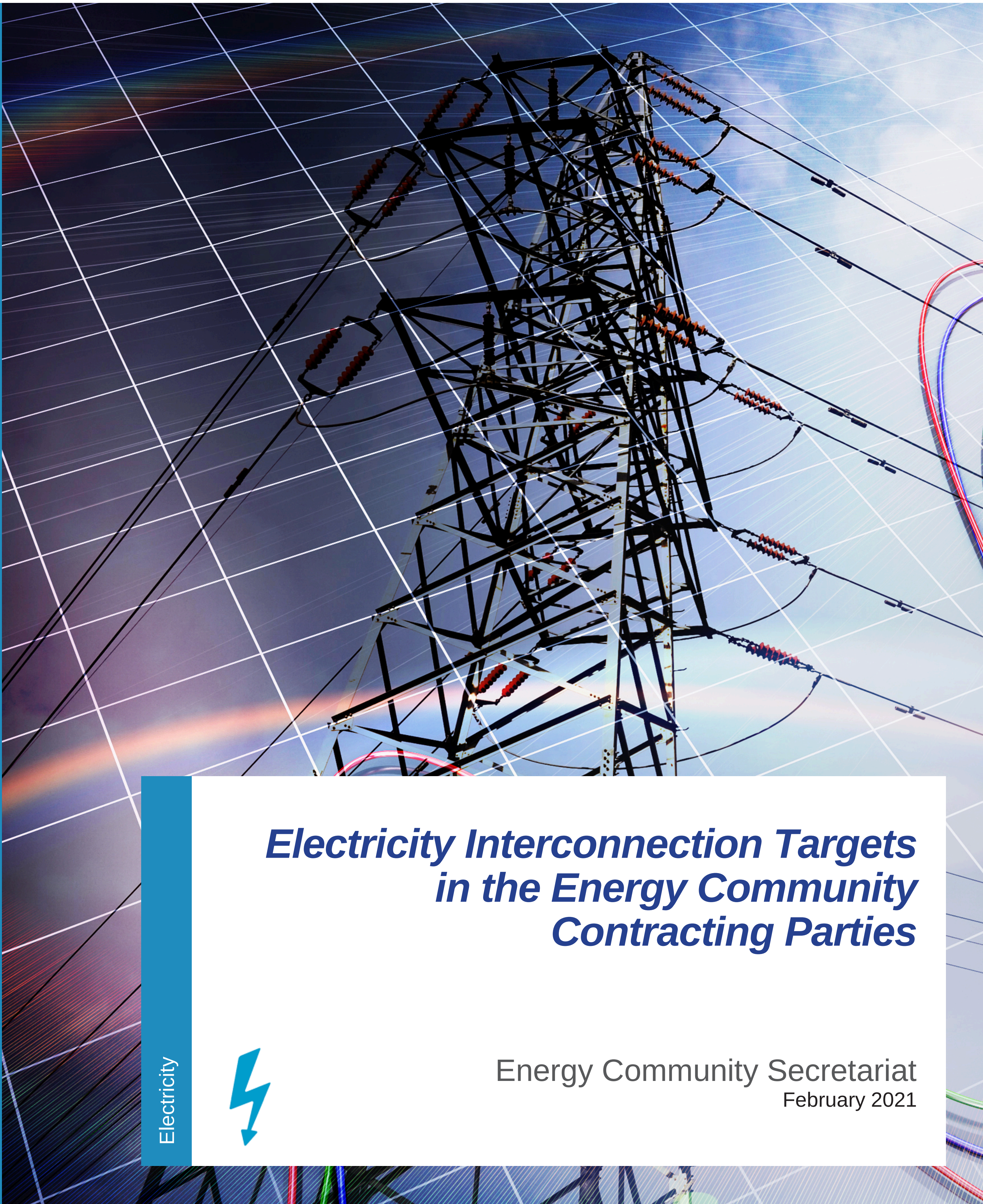


Electricity Interconnection Targets in the Energy Community Contracting Parties

Electricity

Energy Community Secretariat
February 2021

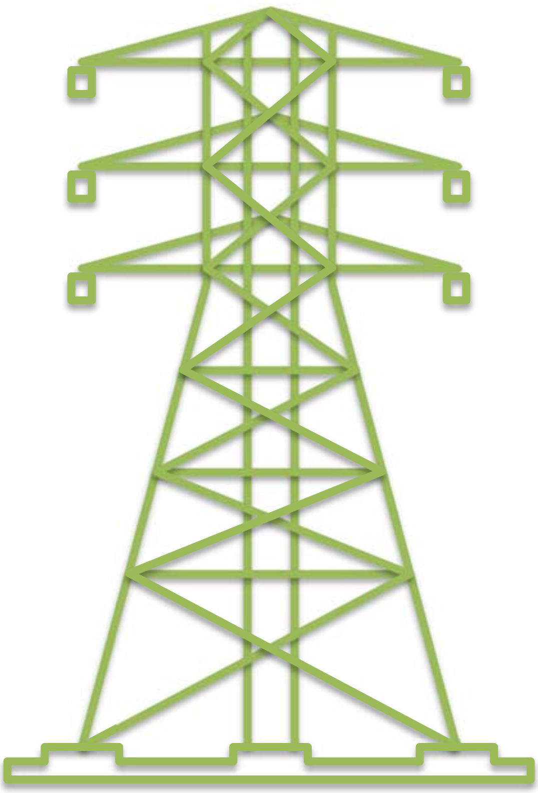
Energy Community Secretariat

Am Hof 4

1010 Vienna

Austria

Study: Electricity interconnection targets in the Energy Community Contracting parties



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Abbreviations

AC	Alternating Current
ATC	Available Transfer Capacity
CP	(Energy Community) Contracting Party
DC	Direct Current
EC	European Commission
ECS	Energy Community Secretariat
EnC	Energy Community
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EU MS	European Union Member State(s
FLH	Full Load Hours
GW	Giga Watt (1000 MW, 1 000 000 kW)
HPP	Hydro Power Plant
HTLS	High Temperature Low Sag (conductors)
HVDC	High Voltage Direct Current
IFI	International Financial Institution
kW	Kilo Watt (1000 W)
MW	Mega Watt (1000 kW)
NECP	Integrated National Energy and Climate Plan
NRA	National Regulatory Agency (for electricity)
NTC	Net Transfer Capacity
PCI	Project of Common Interest
PECI	Project of Energy Community Interest
PMI	Project of Mutual Interest
PV	Photovoltaic
RES	Renewable Energy Source(s)
SEE	South-east Europe
SPP	Solar Power Plant
TEN-E	Trans-European network for electricity
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TW	Tera Watt (1000 GW, 1 000 000 MW, 1 billion kW)
TYNDP	Ten Year Network Development Plan
USSR	Union of Soviet Socialist Republics
WB6	Western Balkans 6 area (Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia, Serbia)
WPP	Wind Power Plant

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Executive Summary

This study observes the Energy Community Contracting Parties' electricity interconnectivity level with respect to the EU 2020 and EU 2030 interconnectivity criteria, in order to estimate further needs and opportunities with respect to power transmission. The EU interconnectivity targets relate to the 10 % criterion in 2020 (10% of net transfer capacity with respect to total production capacity) and the 15 % criterion in 2030, defined through three sub-criteria as follows:

- the wholesale price difference between two bidding zones should be lower than 2 €/MWh; the larger the difference, the greater the need for action;
- the ratio between nominal transmission capacity of interconnectors and peak load should be higher than 30 %; if lower, urgent action is needed. TSOs should consider additional cross-border reinforcements if this ratio is between 30 % and 60 %; and
- the ratio between nominal transmission capacity of interconnectors and installed renewables generation capacity should also be higher than 30 %; if lower, urgent action is needed. TSOs should consider additional cross-border reinforcements if this ratio is between 30 % and 60 %.

The transmission networks of the EnC CPs are more strongly interconnected than those of the majority of EU MS today (in relation to the peak load and installed generation capacity). All observed countries comfortably satisfy the 10 % interconnectivity target, only Ukraine is close to or below this threshold depending on what part of the country is observed (Burshtyn island only or the whole of Ukraine) and which cross-border transmission lines are taken into account (toward ENTSO-E or UPS/IPS or both). Efficient usage and full exploitation of interconnectors is unfortunately still an issue due to low NTC values at the borders, leading to restricted market activities in the observed regions. The restricted NTC values are, however, sufficient to meet the EU interconnectivity target in 2020, but without going significantly above it even though it may be possible using the existing cross-border infrastructure.

The wholesale electricity market price criterion in 2030 and 2040 is observed in this study with respect to the market simulations performed during the PECI/PMI selection process in 2020, without new interconnectors included and with the existing (restricted) NTC values between countries. Results show that differences larger than 2 €/MWh may be expected for some borders in certain scenarios depending on future generation development, integration of RES and demand increase, but are also heavily dependent on the utilisation of existing interconnectors. The borders that could benefit the most from increasing the NTC are the ones between Ukraine and Hungary, Ukraine and Poland, Ukraine and Slovakia, Ukraine and Romania, Ukraine and Moldova, Moldova and Romania and Montenegro and Italy. The other two sub-criteria to measure the interconnectivity level and compliance with the 2030 targets, the ratio between nominal transmission capacity of the interconnectors and peak load and the ratio between nominal transmission capacity of the interconnectors and installed renewables generation capacity, are going to be fulfilled for the vast majority of observed countries even with the existing number and transmission capacity of interconnectors.

The results of the study clearly indicate that **national regulatory authorities and transmission system operators should increase their focus on the efficient usage of the existing interconnectors**. New cross-border projects should only be developed if existing interconnectors would not be capable of fully supporting market activities in the future.

1 Introduction

The European Union has set ambitious goals to be achieved in the following 30 years related to the energy system. The overall objective is to create climate neutral, sustainable, technologically advanced and competitive energy systems, by deploying renewable resources and energy efficiency measures, thus mitigating climate change and creating opportunities for economies to develop under the new circumstances. Electricity, when produced by renewable energy sources like wind, sun, hydro etc., is considered as the most viable option to replace energy sources that emit greenhouse gases. Alongside renewables, measures boosting energy efficiency, technological development and system flexibility will play a key role in ensuring a climate neutral energy supply.

Electricity transmission systems will have a significant role in a decarbonised future due to the following key issues:

- it will be necessary to provide grid connection of large-scale renewable sources like WPPs, SPPs and HPPs, which can benefit from economies of scale, delivering cheap electricity to consumers;
- it will enhance market competition thus increasing economic welfare;
- consumers will benefit from improved security of supply;
- larger areas (possibly inter-continental) with renewable energy sources will be connected thus reducing the need for balancing due to relaxing the intermittency problem (for example when one group of WPPs is not producing, a distant group of WPPs may produce due to the fact that wind speed significantly changes over regions/continents); and
- contributing to environmental protection and air quality, in particular in the regions where coal/lignite was used as the main energy resource.

Power grids will maintain their role in the energy system even under the expected future circumstances with a large share of distributed generation because their aggregated production may occasionally be much higher than local consumption, meaning that extra energy will have to be transmitted toward distant areas. This is also valid in the opposite direction (time periods of low production of distributed generation) when energy will have to be transmitted toward local consumption from distant areas. Application of market mechanisms in the utilisation of resources is the key to unlocking the potential that well interconnected systems provide. Efficient utilisation of transmission interconnections is currently the largest flexibility resource available.

In order to increase market competition and create a pan-European transmission system, the EU has set an electricity interconnectivity target for 2020 and recently also for 2030, reflecting the energy transition process and increasing share of renewable energy sources. Additionally, the EU has started to raise issues about the limited usage of cross-border lines by defining the so-called 70 % minimum target for cross-zonal capacity, as described later in the study.

This study observes the Energy Community Contracting Parties' electricity interconnectivity level with respect to the EU 2020 interconnectivity criteria of 10 % (10 % of net transfer capacity with respect to total production capacity) and the EU 2030 interconnectivity criteria of 15 %, including three sub-criteria (wholesale prices difference, 30 % of nominal transmission capacity with respect to the peak load and 30 % of nominal transmission capacity with respect to installed renewables generation capacity, as described in the following chapter) in order to estimate further needs and opportunities with respect to power transmission.

The main objective of the study is to analyse the state of play of individual Contracting Parties against the 2020 and 2030 EU / European Commission (EC) interconnectivity targets.

Assessments may also provide guidance to the Energy Community Secretariat (ECS), International Financial Institutions (IFIs), Transmission System Operators (TSOs), National Regulatory Agencies (NRAs) and other interested parties on policy measures and ways to assess potential priority infrastructure projects in the Energy Community. The results could also support the regular (every 2 years) evaluation processes of the PECI/PMI candidate projects conducted by the Electricity and Gas groups with the support of the Secretariat.

The expected outcome of the study is as follows:

- assessment of the individual Contracting Parties against the 10 % criterion in 2020;
- assessment of individual Contracting parties against the 15 % criterion in 2030 for different scenarios related to RES development, peak load values and realisation of new cross-border projects, by observing the three sub-criteria defined by the EC (described in the following chapter); and
- evaluation of the state of play on cross-zonal capacity calculation and the level made available to the market.

The study is organised in the following way. After the introductory part, an explanation of the EU interconnectivity targets for 2020 and 2030 is given, indicating how they should be treated and calculated. Chapter 3 contains a short description of each EnC Contracting Party with respect to the existing and future demand, peak load, production facilities including RES, transmission system operation and cross-border interconnection lines. This description is based on publicly available official documents, as well as on data collected by the ECS. All EnC TSOs reviewed the draft version of the study and corrected data about cross-border lines and the maximum NTC values at the borders. Based on uncertain future conditions, different scenarios are defined for each CP related to RES integration, peak load value and new interconnections, as described in Chapter 4. Analysis of the CPs' compliance against interconnection targets in 2020 and 2030 for different future scenarios is given in Chapter 5, while the last Chapter contains conclusions and recommendations based on the previous analysis.

2 EU interconnection targets

Power systems of the EU Member States were historically designed primarily to serve domestic consumers, with limited amount of interconnections which were built to provide emergency support and allow limited bilateral trade.

The European electricity market is specifically designed taking into account limited interconnection capacities between zones, aiming at signalling the right investments in production, storage and network through market mechanisms. Beyond market mechanisms, a concept of trans-European network has been introduced (TEN-E), together with the development of Projects of Common Interest (PCI) and their application in the EnC CPs as Projects of Energy Community Interest (PECI) and Projects of Mutual Interest (PMI) to facilitate investments in electricity infrastructure.

The EU has set an interconnection target of at least 10% by 2020, to encourage EU countries to further develop interconnectors. This means that each country should have in place transmission lines that allow at least 10% of the electricity produced by its power plants to be transported across its borders to neighbouring countries and beyond[1]. The majority of EU Member States have reached (or are close to reaching) this goal but in 2017 there were still eleven EU countries not reaching it [1].

The interconnection target for 2020 of 10 % was related to the ratio between Net Transfer Capacity (NTC) and installed generation capacity in individual countries.

Net Transfer Capacities (maximum possible power import or export over all borders of one country during a certain time period by keeping the predefined security of supply level) were significantly smaller than cross-border lines nominal capacities (maximum possible power transmission over lines with respect to maximum permitted current through these lines), thus restricting market activities (it was estimated that approx. 31 % of nominal capacities were offered to the market in the past period) and creating a large financial income for TSOs due to congestion rents (annual sum of congestion rents in Europe was around 2000 M€, with around a quarter to be spent on capacity increase investments while the rest would go to capacity firmness, decrease of transmission tariffs or was saved on a separate account).

It was also discovered that around 72 % of all congestion cases were caused by internal network bottlenecks, meaning that cross-border capacities were not the only source of restricted market competition, but internal transmission facilities as well [2].

In the meantime, the European Council called on the European Commission to analyse possibilities for Member States to reach a new goal of 15% interconnectivity by 2030.

A new proposal for the interconnection target in 2030 deviates from the above described approach (ratio between the NTCs and installed generation capacities) and observes three additional sub-criteria, described later in this Chapter.

[1] https://ec.europa.eu/energy/topics/infrastructure/electricity-interconnection-targets_en

2.1 Interconnectivity target of 10 % until 2020

The target of 10 % relates to the ratio between the sum of net transfer capacities on a country's borders (or total import capacity) and installed generation capacity in that country.

$$Target\ 10\ \% \xrightarrow{relates\ to} \frac{\sum NTC\ (import\ direction)}{MAX\ P_{generation}} *100\% \geq 10\% \quad (1)$$

where *Σ NTC (import direction)* is the sum of net transfer capacities of all borders surrounding the observed country with respect to the import direction of power flows and $MAX\ P_{generation}$ is installed generation capacity within the observed country.

All EU Member States were called to reach this target until 2020, meaning that they should assure a possibility for market players to put competitive pressure on the domestic generators. Since this target was defined in 2002, it presented at the time a good way forward to facilitate market competition across Europe and its liquidity.

It should be stressed that the "10 % indicator" (the ratio shown above) does not measure the level of interconnectivity in real/physical terms but rather the level of cross-border capacity given to market participants for commercial use (NTC), without jeopardizing the security of supply. The process and methodology for calculation of cross-border capacity is as important as the interconnection assets. The manner in which the NTC or the allowed commercial flows are calculated differs across the continent. If these NTC values were not defined according to the restrictions related to the cross-border lines but due to internal network bottlenecks, or were restricted due to the calculation methodology or any other issue (computational inaccuracies, too restrictive security criteria applied, lack of coordination of adjacent TSOs, etc.), the 10 % indicator could be somehow misleading, indicating that there is an interconnectivity problem instead of a non-efficient interconnection lines usage problem.

RES were at the beginning of this century still an underestimated category and have not been observed within the 10% target.

With approximately 200 GW of installed power in WPPs and 120 GW in SPPs (EU level), the situation has drastically changed. Power flows and electricity exchanges between countries have intensified and become more variable and not easily predicable.

The large number of intermittent electricity sources together with constantly increasing market activities across Europe highlighted that the former interconnectivity target of 10 % should be updated and redefined.

2.2 Interconnectivity target of 15 % until 2030

The European Council in October 2014 endorsed the proposal by the European Commission to extend the current 10 % electricity interconnection target to 15 % by 2030, while taking into account the cost aspects and the potential of commercial exchanges in the relevant regions [2].

The European Commission identified three sub-criteria, which reflect the current situation and represent a fair way to measure interconnectivity levels across Europe with respect to the defined political, economic and technical goals.

The sub-criteria are as follows:

- wholesale price difference between Member States, regions or bidding zones (threshold 2 €/MWh);
- ratio between nominal transmission capacity of interconnectors and peak load (first threshold 30 %, second threshold 60 %); and
- ratio between nominal transmission capacity of interconnectors and installed RES capacity (first threshold 30 %, second threshold 60 %).

Beside the three sub-criteria, the issue of economic viability of new cross-border interconnection lines was stressed. Projects should be implemented only if the potential benefits outweigh the costs and each new interconnector should be subject to a socio-economic and environmental cost-benefit analysis.

2.2.1 Wholesale market price differences

One of the main goals of EU energy policy is to develop competition in production and supply in the organized electricity markets, with the ultimate aim of creating a single European electricity market. In order to allow competition between different electricity production capacities and eliminate market dominance of any single competitor, the pan-European transmission system should be ideally constructed in a way that all possible structural congestions are avoided, meaning that wholesale price differences would be minimized or reduced to zero.

A well-functioning internal market should lead to competitive electricity prices for all Europeans. Member States should therefore aim at minimising differences in their wholesale market prices [2]. Additional interconnections should be prioritised if the price differential exceeds an indicative threshold of 2 €/MWh between Member States, regions or bidding zones. The higher the price differential is, the greater is the need for urgent action.

The price difference could be a very effective market signal, indicating a necessity for placing a new interconnection between two countries/areas/zones and that existing interconnection lines (if any) might be congested not allowing cheaper electricity to flow over an interface to the other side where the price is higher. This signal shall be considered only if the interconnection lines in operation are efficiently utilised (for example when markets are coupled or at least 70 % of the capacity is available to market participants through coordinated capacity calculation). If capacity was offered through auctions with a low level of NTC values, a significant price difference might not indicate the need for a new interconnection line but rather restricted market functionality.

It is understandable that average annual wholesale prices should be used when evaluating this criterion, not hourly price differences which may significantly vary over the year.

$$\mathit{Target}\ 15\ \%(\mathit{sub}-\mathit{criterion}\ 1) \xrightarrow{\mathit{relates\ to}} \Delta(\mathit{AVG\ price}_A - \mathit{AVG\ price}_B) < 2\ €/\mathit{MWh} \quad (2)$$

where $AVG\ price_A$ is the average annual wholesale market price in country A and $AVG\ price_B$ is the average annual wholesale market price in country B.

2.2.2 Ratio between nominal transmission capacity of interconnectors and peak load

Power systems, including transmission systems, should be designed to satisfy existing and expected future peak load (maximum hourly electricity consumption within one country) at all times and under all circumstances, or to satisfy it with a predefined level of probability (security of supply target) if the probabilistic planning approach is adopted within a specific TSO competence area. Under ideal market conditions, the peak load of one country will be supplied by domestic production and energy imports through the interconnection lines in the most economically optimal way. The economic optimum will be ruined if interconnection lines restrict possible import of cheaper electricity than may be produced by domestic power plants, increasing prices in the observed country/area and decreasing the socio-economic welfare of this country.

Import of cheaper electricity would not be possible without interconnectors and their transmission capacity will determine how much of it may be brought to the system. Nominal transmission capacities of the interconnectors are determined by the voltage and maximum permitted current which may flow through wires without increasing their temperature above a predefined threshold. Contrary, NTC values are determined with respect to the security of supply taking into account different assumptions and possible, albeit rare, events (like forced outages, combinations of planned and forced outages and similar). The EU Commission stands at the point that nominal transmission capacity of interconnectors should be observed instead of the NTC values. We should have in mind also the fact that interconnectors could not be loaded up to their maximum permitted level at the same time due to the laws of physics and meshed networks in which electricity flows through different pathways. However, with the assumption that interconnectors are going to be efficiently used under market conditions, nominal transmission capacity as a restrictive value seems more appropriate than the NTC value that is agreed between adjacent TSOs, especially expecting European wide market coupling in the future.

$$\boldsymbol{Target\ 15\ \%(sub-criterion\ 2)} \xrightarrow{relates\ to} \frac{\sum P_n}{MAX\ P_{load}} * 100\% > 30\% \quad (3)$$

where ΣP_n is the sum of nominal transmission capacities of all interconnectors in one country and $MAX\ P_{load}$ is peak load related to the observed time period.

For the purpose of this study, nominal transmission capacities will include all cross-border lines of one country connecting it with the neighbouring countries operating within the same synchronous zone. For the WB6 countries (Albania, Bosnia and Herzegovina, Kosovo*[2], Montenegro, North Macedonia and Serbia), this will include all of their interconnectors (because all neighbouring countries operate within ENTSO-E), while for Ukraine, Moldova and Georgia individual approaches will be used, described further on in the study.

A ratio between nominal transmission capacity of interconnectors and peak load lower than 30 % means that there is a real necessity to examine possibilities to reinforce interconnections. A ratio of between 30 % and 60 % means that TSOs shall monitor the situation and possibly start to develop new interconnection project(s), while a ratio above 60 % means that there is probably no need to further reinforce interconnectors, at least with respect to the observed criterion.

[2] * 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.

2.2.3 Ratio between nominal transmission capacity of interconnectors and installed power of renewable energy sources

It is expected that the generation mix in Europe, including EnC CPs, will be significantly changed with wind and solar power plants dominating electricity production together with existing and future hydro capacities, while electricity production from coal fired power plants is going to be significantly decreasing, dropping to zero when full decarbonisation is reached in 2050.

Since utilisation rates (full load hours, capacity factor) for wind and solar power plants are much lower than for fossil fuel power plants (especially coal fired), which will eventually leave the generation mix, for the same amount of energy there is significantly higher installed capacity needed. One coal fired power plant of 500 MW would normally produce around 3.5 TWh/year (full load hours - FLH around 7000 h[3]), while for the same amount of electricity approximately 1600 MW of onshore WPPs (FLH ~ 2200 h[4]) or 3500 MW of SPPs (FLH ~ 1000 h) are needed.

Furthermore, since the production of WPPs and SPPs is generally variable/intermittent and strongly dependent on the season/month/part of the day[5], the transmission system (as well as the distribution system affected by increased distributed generation) may be exposed to very variable power flows, together with significant imports (when RES production is missing) or electricity exports (when RES production is excessive).

The measure of interconnectivity could also be defined in relation to total RES installed capacity since the transmission system in general and cross-border interconnections in particular should be designed to support these imports and exports of electricity with minimum curtailment of RES production due to possible operational problems and non-fulfilment of operational security criteria (like the n-1 security criterion). Moreover, interconnection capacity adds to the needed flexibility of the system to manage the increasing inflow of renewables.

$$\boldsymbol{Target\ 15\ \%\ (sub-criterion\ 3)} \xrightarrow{relates\ to} \frac{\sum P_n}{MAX\ P_{RES\_generation}} * 100\% > 30\% \quad (4)$$

where ΣP_n is the sum of nominal transmission capacity of all interconnectors in one country and $MAX\ P_{RES\_generation}$ is the installed generation capacity of RES within the observed country.

A ratio between nominal transmission capacities of interconnectors and installed renewable generation capacity lower than 30 % means that there is a real necessity to examine possibilities to reinforce interconnections. A ratio between 30 % and 60 % means that the TSOs shall monitor the situation and possibly start do develop new interconnection project(s), while a ratio above 60 % means that there is probably no need to further reinforce interconnectors with respect to the observed criterion.

[3] Assumed availability rate of 80 % and base load operation.
[4] This would not be valid for offshore WPPS where FLH may go up to 5000 h.
[5] Correlation of simultaneous WPPs, SPPs and HPPs production should be also observed, while WPPs and HPPs are often complementary, this might not be the case for SPPs, although this depends on local climate particularities.

2.3 Efficient usage of existing interconnectors (70 % request)

Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity [4] identifies uncoordinated curtailments of interconnector capacities as one of the most serious obstacles to the development of the internal EU market for electricity. It calls for the maximum availability of interconnector capacity to market participants, respecting safety and security standards of network operation including contingencies. It also defines that the transmission capacity to which at least the 70 % minimum capacity criterion shall apply in the NTC approach is the maximum transmission of active power which respects operational security limits[6] and takes into account contingencies, while the reliability margin, loop flows or internal flows are taken into account within the remaining 30 %.

Article 16(8) of this Regulation defines that „Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones. This paragraph shall be considered to be complied with where the following minimum levels of available capacity for cross-zonal trade are reached:

(a) for borders using a coordinated net transmission capacity approach, the minimum capacity shall be 70 % of the transmission capacity respecting operational security limits after deduction of contingencies;

(b) for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 % of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies".

TSOs that do not meet this requirement are obliged to present an action plan on increasing the cross-zonal trade capacity until the minimum of 70 % of the transmission capacity is offered to the market participants at the latest in 2025. On 8 October 2019, ACER issued a Recommendation to national regulatory authorities to implement a consistent approach when monitoring this requirement. According to this Recommendation, the capacity calculation within a coordination area needs to take into account the impact that bidding-zone borders outside such a coordination area have on the physical flows on the critical network elements used within such a coordination area (Capacity Calculation Region – CCR). As the CCRs currently include only EU Member States, the consideration of flows from third countries is possible in case an agreement has been concluded by all TSOs of a CCR with the TSO of the third country. ACER already issued the first Monitoring Report on the compliance of EU Member States' TSOs with this requirement.

The Energy Community Regulatory Board published a report in December 2020 assessing the level of compliance of the EnC CPs with the 70 % requirement, though it is not binding for the CPs. The assessment shows that, based on 2019 data, the WB6 TSOs offer to the market around 30 % of the nominal interconnection capacity. In addition, the report points to a conservative approach in calculating capacity as the calculation process and the methodology is not being coordinated and updated with short-term calculations (D-2).

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[6] As defined within the *Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management* 'operational security limits' means the acceptable operating boundaries for secure grid operation such as thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits.

The previously described provision will lead to increasing exchanges of electricity over borders, and once adopted in the EnC CPs, is expected to result in an increase of the NTC values offered to market participants, which in turn will mean that existing interconnectors are used more efficiently. The expected significant increase of cross-border capacities offered to the market may positively influence large-scale integration of RES and decrease electricity production of carbon intensive power plants. The increase of the NTC values or market coupling will decrease price differences between neighbouring countries, which will have significant impact on the sub-criterion 1 previously described in chapter 2.2.1.

It shall be stressed again that wholesale price difference criterion of the interconnectivity level must not be observed in a situation where existing interconnectors are not used efficiently, meaning that NTC values are several times lower than nominal transmission capacity of interconnectors at the observed borders. Wholesale prices could be a good measure of the interconnectivity if they are calculated with maximum capacities of existing interconnectors which can be offered to the market, respecting the network's operational security limits.

3 Interconnectivity of the Energy Community Contracting Parties

This chapter shortly describes individual Contracting Parties' power transmission systems, including the existing situation and future design according to the national TYNDPs. Special attention is directed to cross-border transmission lines and their usage today. Basic data about electricity consumption/load and generation mix are also given.

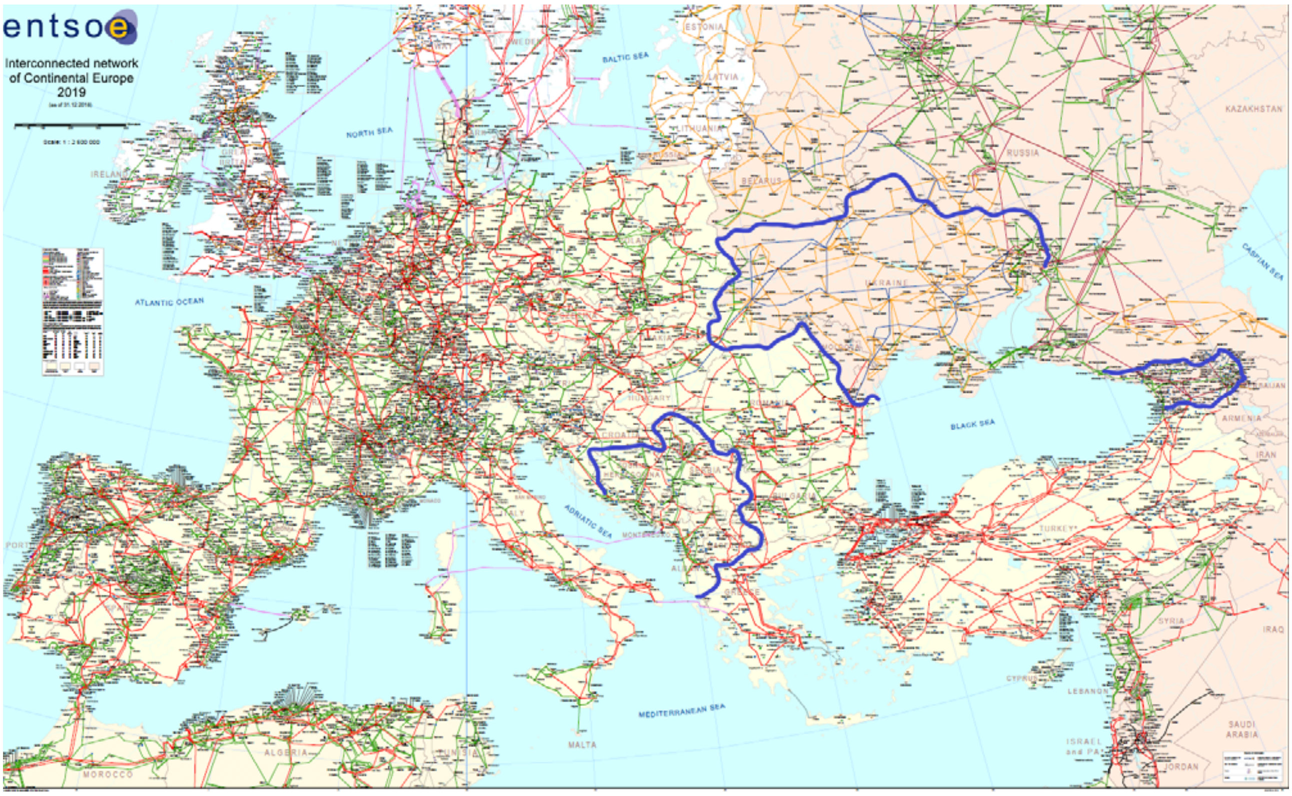

Figure 1: Position of the EnC Contracting Parties within the ENTSO-E transmission system
Source of the base map: ENTSO-E

Tables in the following sub-chapters contain lists of the interconnection lines in all Contracting Parties (existing and planned ones in the short-term, mid-term and long-term future), with their ratings (I_{max} is the maximum permitted current through a line in normal operation, S_n refers to the apparent power, while P_n is estimated maximum active power[7]). Short-term (usually 30 minutes) permitted overloading limits are not taken into consideration here. Actual over-current protection settings are also not included. Data in the tables are based on official sources and coordinated in a way that one value is related to one line at both sides. In case transmission capacity was declared differently on each side of the border, the smaller value was defined for the observed line in its total length. The same is valid if two values for nominal transmission capacity were defined for the same border with respect to the winter and summer season, the smaller value was taken. This approach leads to the smallest values of the nominal transmission capacity of the interconnectors being used

[7] Calculated here as 90 % of the S_n (10 % margin is defined to take into account the reactive component of the apparent power) that will always flow through a line, using usually a smaller part of its nominal transmission capacity.

in the calculations. In many situations, the transmission lines could be loaded more, depending on the actual operating situation and climate conditions at the specific moment in time. One limiting factor is linked to the metering current transformers in substation bays, which may not have been adjusted to the maximum permitted current of the conductors; however, this is neglected in this study due to lack of data.

The following sub-chapters also contain the maximum NTC values for all CPs borders collected from different official documents and provided by some TSOs. The maximum NTC values for the WB6 countries were collected from the *Ten Year Network Development Plan 2020: Regional investment plan Continental South East* (August 2020) [17], based on year 2018, but updated by all TSOs to existing values on their borders. Values shown are the maximum NTC values reached at a certain border during the observed year. Hourly distribution of the NTC values were unknown to the Authors, so average NTC values could not be calculated at this point of time. The NTC values for Kosovo* and the borders between Serbia, Montenegro and North Macedonia were determined according to data used in the PECI/PMI selection process in 2020 (not prejudging the real values which will be calculated and agreed among the TSOs involved) because the previous reference (TYNDP 2020 RG CSE) does not contain these data, while data for Moldova and Georgia are based on their development plans (national TYNDPs) listed in Chapter 7. Data for Ukrainian borders were provided by Ukrenergo.

It shall be noted that the above mentioned targets and requirements in relation to interconnection capacity are not binding for the EnC CPs in the same manner as they apply for the EU Member States. CPs TSOs have the obligation to maximise the cross-border capacity offered to the market and from this point of view the targets applied in the EU represent a firm benchmark towards which the CPs shall work.

3.1 Albania

Albania's electricity consumption is around 6.5 TWh/year to 7 TWh/year, with the peak load value reaching 1400 MW, and minimum load value going down to cca. 400 MW. The generation mix is largely based on HPPs. The total installed power of the power plants is around 2200 MW [5], with the majority of generators (70 %) connected to the 220 kV network. Their annual production varies between 2.8 TWh/year and 8.5 TWh/year, meaning that Albania sometimes depends on electricity imports, but other times has energy to sell abroad. The Albanian TSO (OST) expects that new generation capacities (at least between 300 MW and 1100 MW) will be constructed in the following ten years, mainly HPPs.

The transmission system consists of 400 kV, 220 kV, 150 kV and 110 kV transmission lines and transformers, with a meshed 220 kV network structure in the central part of the country with the highest consumption, and a radial structure of the 400 kV network that contains the most important cross-border lines. There are six interconnection lines with neighbouring countries (3 400 kV lines, 2 220 kV lines and one 150 kV line), with an additional 400 kV interconnection line under construction towards North Macedonia, expected to be operational from 2023. After that date, Albania will be connected with all neighbouring countries (Montenegro, Kosovo*, North Macedonia and Greece) with one 400 kV line to each.

Beside the new interconnector to North Macedonia, the Albanian TSO is considering to construct an additional 400 kV interconnection to Greece (SS Fier to still undefined substation in Greece), together with internal 400 kV network reinforcements (Fier – Rrashbull). This project is at the very first stage of consideration, without prefeasibility and feasibility studies. There were also discussions about a possible HVDC link to Italy in the past, mainly initiated by private investors with a goal to develop large WPPs in Albania and transmit their production toward Italy. This idea has not become mature enough to develop further. The total nominal capacity of interconnectors at Albanian borders today is around 4100 MW, and will soon reach 5300 MW when the 400 kV new line toward North Macedonia enters into operation.

Figure 2: Transmission system of Albania (existing situation)   Source: OST

Table 1: Albanian power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From Albania to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
400	Zemblak	Kardia	Greece	1970	1350	1215
400	Tirana 2	Podgorica	Montenegro	1920	1330	1197
400	Komani	Kosova B	Kosovo*	1900	1317	1185
220	Koplik	Podgorica	Montenegro	790	300	270
220	Fierze	Prizreni 2	Kosovo*	790	300	270
				ALL (existing situation)	**4597**	**4137**
PLANNED LINES						
400[1]	Elbasan	Bitola	North Macedonia	1920	1330	1195
				ALL new (short time-frame)	**1330**	**1195**
				Existing+planned (short-time frame)	**5927**	**5332**
				Existing+planned (mid-time frame)	**5927**	**5332**
				Existing+planned (long-time frame)	**5927**	**5332**

[1] expected to be in operation from 2023

The following table shows indicative NTC values at Albanian borders according to the Regional CSE group of ENTSO-E [17] but updated by OST. Comparing the NTC values with the nominal transmission capacities of the interconnectors at each border, 17 % to 27 % of the nominal transmission capacity has been offered to the market participants (between 27% and 33% in the new situation from 14 December 2020[8]). By comparing the overall values (sum of NTCs over all borders and sum of nominal transmission capacities over all borders), the value of 22 % is reached with respect to the nominal transmission capacities offered to the market participants (29% in the actual situation from December 2020). The new interconnection line between Albania and North Macedonia that is under construction will provide new transmission capacity to be offered to the market participants of 500 MW to 600 MW, depending on the data source (the larger value was defined during the PECI/PMI selection process in 2018 when this project received the PECI label).

Table 2: Indicative (maximum) NTC values at Albanian borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
Albania – Montenegro	441	400	1467
Albania – Greece	250 (400*)	250 (400*)	1215
Albania – Kosovo*	250 (400*)	250 (400*)	1455
TOTAL	**941 (1241*)**	**900 (1200*)**	**4137**

* since December 2020

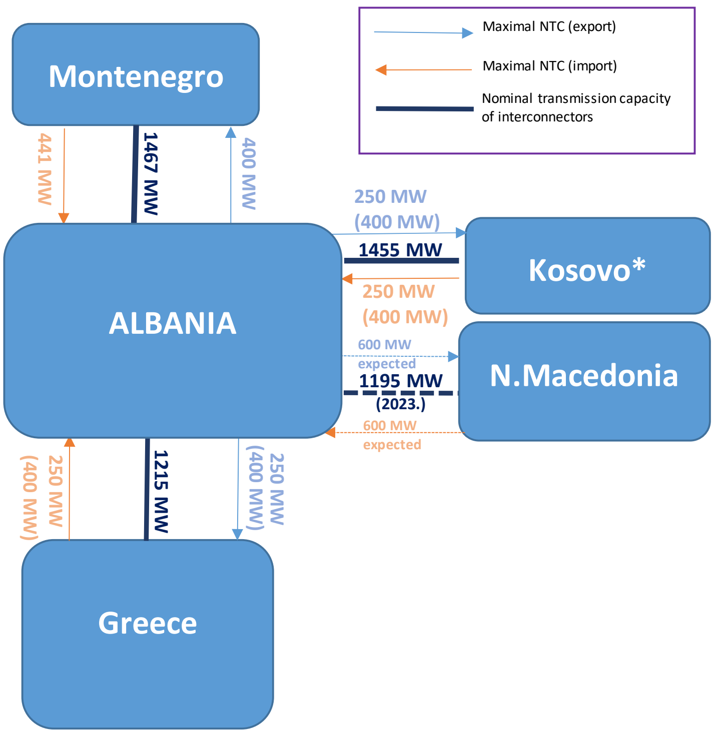

Figure 3: Nominal transmission capacity of the interconnectors at Albanian borders and maximum NTC values

[8] The start of operation of the 400 kV line Tirana 2 – Komani – Kosovo B in December 2020 allowed the NTCs to increase at the borders with Kosovo* and Greece to 400 MW (previously 250 MW).

3.2 Bosnia and Herzegovina

Bosnia and Herzegovina’s electricity consumption is around 12 TWh/year to 13 TWh/year, with the peak load value reaching 2000 MW and a minimum load of approximately 700 MW. Available energy over the transmission system, consisting of 400 kV, 220 kV and 110 kV voltage levels, was around 18 TWh in 2019, with approximately 15 TWh of domestic production and 3 TWh of electricity imports, but these numbers highly depend on the hydrological conditions in an observed year [6]. Predictions are that electricity consumption will stagnate or slightly rise up to 12 TWh-13.8 TWh in the following ten years [6].

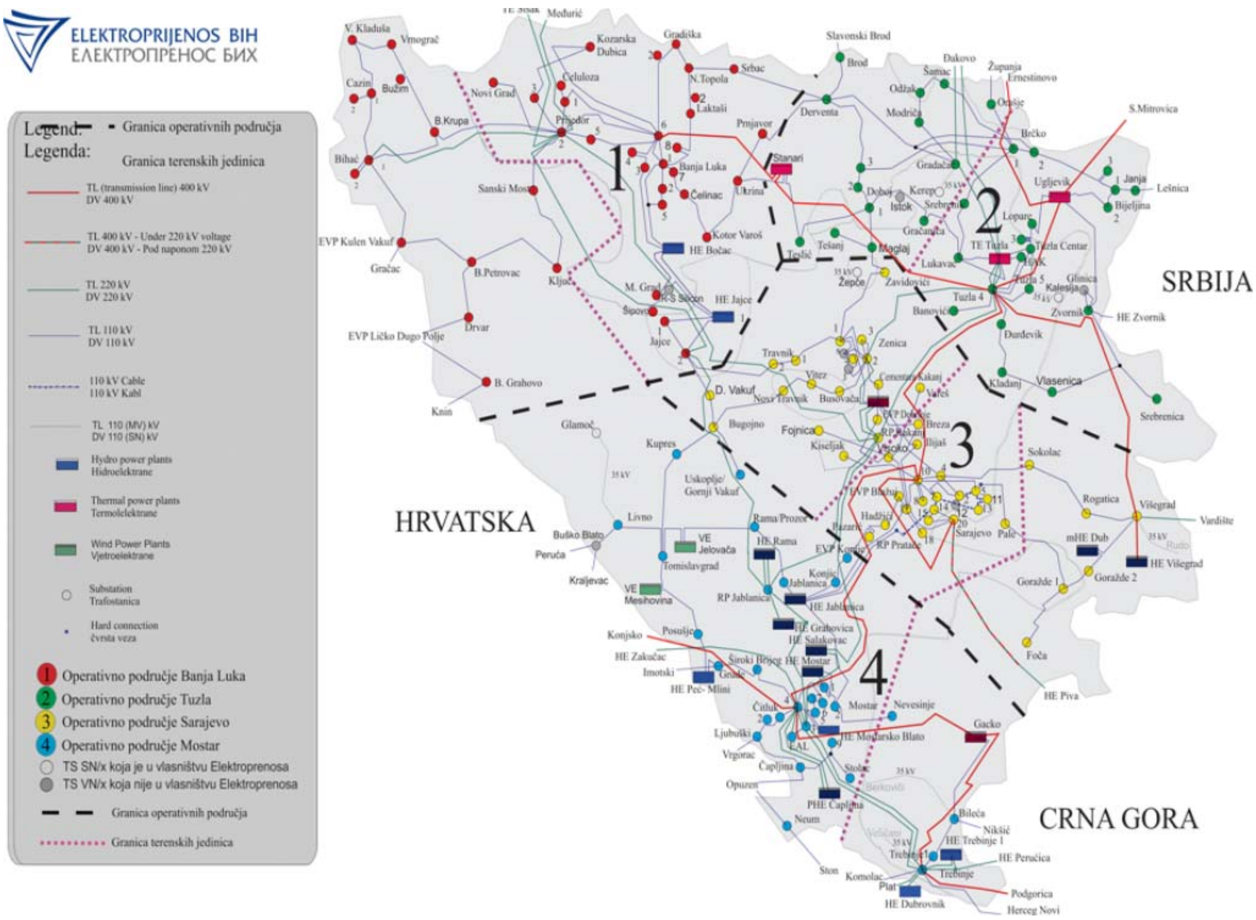

Figure 4: Transmission system of Bosnia and Herzegovina (existing situation)
Source: Elektroprijenos BiH

The generation mix consists of hydro power plants (2105 MW) and coal fired thermal power plants (1888 MW), while RES installed capacity (mainly WPPs) is still small (87 MW). Distributed energy sources are limited in size (mainly small HPPs).

The current generation expansion plan [6], prepared by NOS BiH, defines new generation capacity in the following ten years at 872 MW mainly in two new coal fired units (450 MW+300 MW, TPP Tuzla 7 and TPP Kakanj 8), while the rest is related to one WPP and two smaller HPPs. However, there is significant interest in new renewable energy sources (WPPs and SPPs), so it is highly probable that RES is going to expand significantly. At the same time, significant installed capacity of existing coal fired units will be decommissioned (five units, ~ 700 MW in total).

The 400 kV transmission network is meshed with Croatia with the ring going from the northeast of the country to the southwest, where the main consumption centres are located (Sarajevo, Tuzla and Mostar), with one radial line going toward the city of Banja Luka.

Table 3: Bosnia and Herzegovina power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From Bosnia and Herzegovina to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
400	Ugljevik	S. Mitrovica	Serbia	1920	1329	1196
400	Ugljevik	Ernestinovo	Croatia	1920	1329	1196
400	Mostar	Konjsko	Croatia	1920	1329	1196
400	Trebinje	Lastva	Montenegro	1920	1329	1196
220	Visegrad	Vardiste	Serbia	790	301	271
220	Sarajevo 20	Piva	Montenegro	960	365	329
220	Trebinje	Perucica	Montenegro	790	301	271
220	Tuzla	Djakovo	Croatia	790	301	271
220	Gradacac	Djakovo	Croatia	790	301	271
220	Prijedor	Medjuric	Croatia	790	301	271
220	Prijedor	TPP Sisak	Croatia	790	301	271
220	Mostar	Zakucac	Croatia	790	301	271
220	Trebinje	Plat	Croatia	1290	491	442
Radially operated lines						
220	Trebinje	Dubrovnik G2	Croatia	1290	491	442
ALL (existing situation, without radially operated lines)					**8276**	**7448**
PLANNED LINES						
-	-	-	-	-	-	-
ALL new (short time-frame)					**0**	**0**
Existing+planned (short-time frame)					**8767**	**7890**
400[1]	Visegrad	Bajina Basta	Serbia	1920	1329	1196
Existing+planned (mid-time frame)					**9604**	**8644**
400[2]	Banja Luka	Lika	Croatia	1920	1329	1196
Existing+planned (long-time frame)					**10933**	**9840**

[1] expected to be in operation from 2026; [2] expected to be in operation from 2030

Bosnia and Herzegovina's power production companies usually export electricity over the borders toward Croatia, Serbia and Montenegro. Electricity export in 2019 was 6,5 TWh. There is a significant number of 400 kV and 220 kV cross-border lines to support the large electricity exports (or imports). Bosnia and Herzegovina is well connected with all neighbouring countries (Croatia: two 400 kV lines and seven 220 kV lines; Serbia: one 400 kV line and one 220 kV line; Montenegro: one 400 kV line and two 220 kV lines). The total nominal capacity of interconnectors in Bosnia and Herzegovina is around 7900 MW in the existing situation (~440 MW should be excluded because it refers to one radial 220 kV line connecting the generator at the territory of Croatia directly to the BiH transmission system) and expected to be increased even more up to 10300 MW when new interconnection projects are going to be realized (planned new 400 kV lines to Serbia and Croatia). This huge cross-border capacity might be large enough to support further integration of RES until 2030 and market activities within the region.

The following table shows indicative (maximum) NTC values at observed borders of Bosnia and Herzegovina and neighbouring countries. The maximum NTC values are in the range between 24 % (border with Croatia) and 41 % (border with Serbia) of the nominal transmission capacity of the interconnectors at the observed borders. Since interconnectors over the Bosnian and Herzegovinian and Croatian border have the highest nominal transmission capacity and only a small portion of it is offered to the market participants, it is probable that internal network bottlenecks prevent higher usage of these interconnectors closer to its full transmission capacity. This means that the 110 kV and 220 kV networks represent the real limitation for cross-border trade in Bosnia and Herzegovina, not the interconnection lines. By comparing the overall values (sum of NTCs over all borders and sum of nominal transmission capacities over all borders), we may reach the value of 28 % with respect to the nominal transmission capacities offered to the market participants. Having in mind that the peak load in Bosnia and Herzegovina is around 2000 MW and installed power of generators is around 4000 MW, the offered transmission capacity still represents a significant amount to cover domestic needs or allow trading of domestic producers, but might restrict market activities of other participants today or possible large-scale RES producers in the future.

Table 4: Indicative (maximum) NTC values at Bosnian and Herzegovinian borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
BiH – Croatia	1000	1000	4186
BiH – Serbia	600	600	1466
BiH – Montenegro	500	500	1795
TOTAL	**2100**	**2100**	**7448**

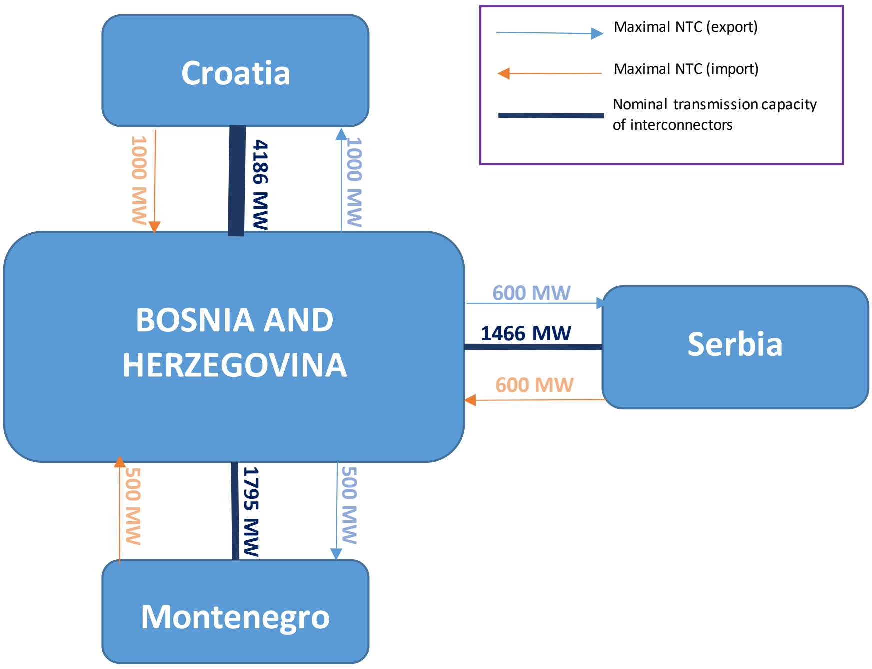

Figure 5: Nominal transmission capacity of the interconnectors at BiH borders and maximum NTC values

3.3 Georgia

Georgia's electricity consumption is around 12 TWh/year but constantly rising. The peak load is around 2000 MW. Georgian expectations are that electricity consumption will increase to 23 TWh/year until 2030 and even 55 TWh/year in 2050 (source: PECI/PMI selection process 2020, data delivered by the Georgian State Electrosystem - GSE). The generation mix consists of hydro power plants (2381 MW in the accumulation ones and 919 MW in the run-of-river ones), gas turbines (110 MW), thermal power plants and combined cycle gas turbines (815 MW) and wind power plants (21 MW), which makes total installed generation capacity of 4246 MW. Electricity is produced mainly by hydro power plants (around 75 %) but Georgia is dependent on thermal production because HPPs produce mostly during summertime when demand is low and less during wintertime when demand is high. For the same reason, the country imports electricity during winter and exports it during summer.

Figure 6: Transmission system of Georgia (existing situation) [8]
Source: JSC "Georgian State Electrosystem"

Georgia's transmission system operates synchronously with Russia and Azerbaijan, but it is also connected with one AC line to Armenia and one HVDC line to Turkey, with additional two 220 kV lines to Russia and Turkey operating in an isolated mode only. Transmission voltage levels are 500 kV, 400 kV, 330 kV, 220 kV and 110 kV, with a 500 kV meshed network in the central part but connected radially with a very long line to the largest hydro power plant Enguri (1200 MW) and the transmission system of Russia. This leads to forced outages of this line, which regularly causes power blackouts in the wider Tbilisi area and central Georgia. Cross-border lines of the Georgian transmission network are not backed-up and their outages create a risk of emergency [8].

Georgian plans for future generation capacities and transmission reinforcements are very ambitious. The latest version of the TYNDP [8] estimates total installed generation capacity in 2030 at 9740 MW, distributed over the new accumulation HPPs (4097 MW), run-of-river HPPs (2438 MW), combined cycle and coal fired TPPs (1345 MW), wind farms (1330 MW) and solar power plants (520 MW). At the same time, significant investments in internal network reinforcements and further increase of the cross-border capacities have been planned, like construction (rehabilitation of the old line) of the new 330 kV line to Azerbaijan (under construction in 2020), 500 kV line to Russia (500 kV OHL Ksani-Stepantsminda-Mozdok), Armenia (HVDC B2B link 500 kV OHL Marneuli-Airum) and HVDC B2B links towards Turkey (400 kV OHL Akhaltsikhe-Tortum and 350 MW HVDC back-to-back link at SS Akhaltsikhe; 154 kV OHL Batumi-Muratli and 350 MW HVDC back-to-back link at SS Batumi). Under study is one more HVDC link between Georgia and Romania, which is planned to be located under the Black Sea. The rationale for this link is to create opportunities for Georgia to participate in the European electricity market, since there are no other ways to connect the country with any EU Member State.

The following table shows Georgian interconnection lines which are in operation and those that are planned to be constructed. Data for 500 kV lines toward Russia and Azerbaijan were assumed by the Authors based on their voltage level, material and cross-section of the conductors.

Table 5: Georgian power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From Georgia to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
500	Enguri	Centralnaina	Russia	1965	1700	1530
500	Gardabani	Samukh	Azerbaijan	1965	1700	1530
330	Gardabani	Agstapa	Azerbaijan	-	-	210
400 (HVDC)	Akhaltsikhe	Borchkha	Turkey	-	-	700
Radially operated lines						
220[1]	Gardabani	Alaverdi	Armenia	700	266	240
220[1]	Batumi	Khopa	Turkey	-	-	110
220[1]	Bzipi	Psou	Russia	-	-	150
ALL (existing situation, without radially operated lines)					**-**	**3970**
PLANNED LINES						
330[2]	Gardabani	Agstapa	Azerbaijan	1380	789	710
400 (HVDC)[2]	Akhaltsikhe	Tortum	Turkey	-	-	350
400 (HVDC)[3]	Marneuli	Ayrum	Armenia	-	-	700
ALL new (short time-frame, without radially operated lines)					**-**	**1060**
Existing+planned (short-time frame, without radially operated lines)					**6046**	**5030**
500[4]	Stepantsminda	Mozdok	Russia	1965	1700	1530
154 (HVDC)	Batumi	Muratli	Turkey	-	-	350
Existing+planned (mid-time frame, without radially operated lines)					**-**	**6910**
500 (HVDC)[5]	Anaklia	Constanta	Romania	-	-	1000
Existing+planned (long-time frame, without radially operated lines)					**-**	**7910**

[1] isolated operation; [2] expected to be in operation from 2022; [3] expected to be in operation from 2023
[4] expected to be in operation from 2025; [5] expected to be in operation from 2030

It should be stressed that the Georgian TSO (GSE) heavily restricts loading of the 500 kV lines to Russia and Azerbaijan due to the following reasons, as described by GSE:

- their age (the 500 kV line to Russia was constructed in 1984 and to Azerbaijan in 1989/2011);
- the lines have been operating in very tough conditions and not maintained/rehabilitated regularly; and
- maximum permitted loading of the lines has been determined by the infrastructure owners and forwarded to GSE.

Due to the abovementioned reasons, GSE considers the maximum permitted loading of the 500 kV line Enguri – Centralnaina to be 570 MW and of the 500 kV line Gardabani – Samukh to be 630 MW, which are three times lower than the expected values for the same conductors in good shape. Nominal transmission capacity of the interconnectors under present and future circumstances varies significantly based on the assumptions about realistic maximum permitted loading of these lines, which is reflected in the presented study.

Instead of calculating the NTC values, the Georgian TSO indicated Total Transfer Capacities (TTC) in their TYNDP [8]. Exchange possibilities are significant with respect to the borders with Russia, Azerbaijan and Turkey, but limited at the Armenian border. For now, large-scale market activities in the region around Georgia are restricted, not only due to the different synchronous areas but also due to limited capacities of transmission lines inside Georgia and at its borders.

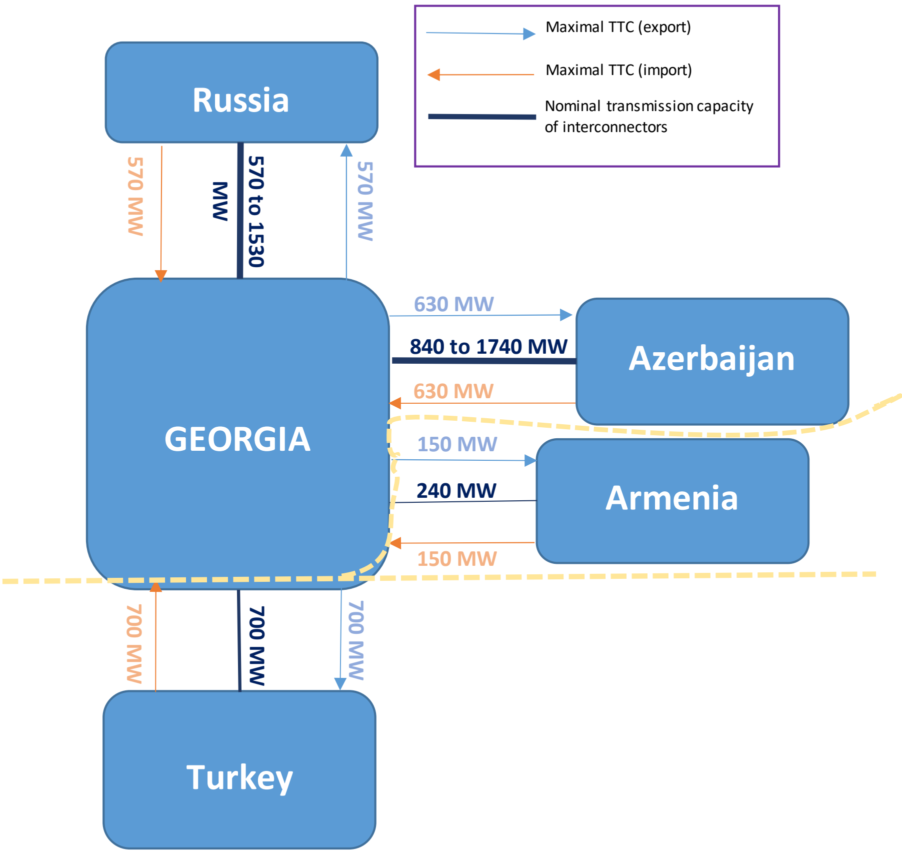

Figure 7: Nominal transmission capacity of the interconnectors at Georgian borders and TTC values

Table 6: TTC values at Georgian borders

Borders	Import (MW)	Export (MW)	Total transmission capacity of interconnectors at the border (MW)
Georgia – Russia	570	570	1530
Georgia – Azerbaijan	630	630	1740
Georgia – Armenia	150	150	240
Georgia – Turkey	700	700	700
TOTAL	**2050**	**2050**	**4210**

3.4 Kosovo*

Electricity consumption in Kosovo* is close to 6.1 TWh/year and rising since 2000. The peak load reaches 1260 MW, regularly occurring during wintertime, with summertime maximum load values in a range of 65% to 70% of the peak load. The minimum load value is slightly below 300 MW. Predictions from the TYNDP prepared by KOSTT [9] are that peak load may reach a value between 1150 MW and 1400 MW in the following ten years.

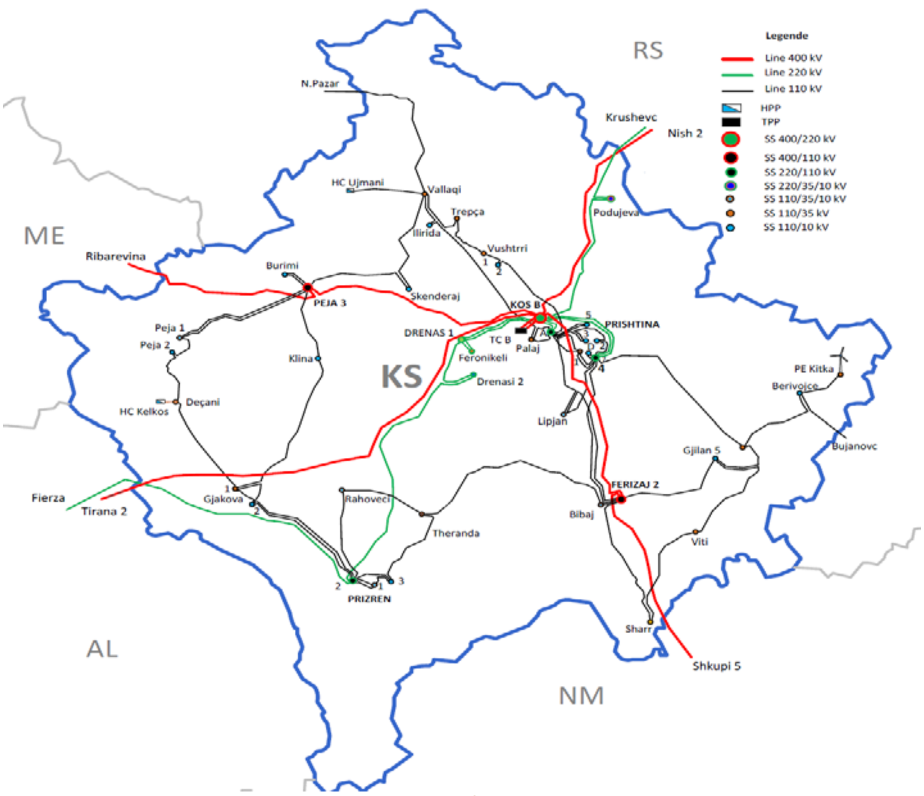

Figure 8: Transmission system of Kosovo (existing situation) [9]*
Source: KOSTT

Kosovo*'s generation fleet consists mainly of two coal fired power plants (Kosovo A and B, five units) of total installed power of 1299 MW (available between 760 MW and 915 MW) and renewable energy capacities of 139 MW (net), mainly in hydro power plants and wind power plants connected to the transmission network (total 99 MW) and small HPPs and solar power plants connected to the distribution network (total 44 MW). Due to poor flexibility of the existing thermal units, Kosovo* suffers from occasional misbalances in both directions (excessive production and lack of production), resulting in the TSO (KOSTT) having to procure frequency control ancillary services from abroad (Albania).

The transmission network operates under 400 kV, 220 kV and 110 kV voltage levels, with approximately 1430 km of overhead lines and 37 substations 400/x kV, 220/x kV and 110/x kV [9]. 400 kV and 220 kV networks are not meshed within the country so the transmission system's reliability is highly dependent on cross-border lines and neighbouring transmission systems. Kosovo* is well connected with all neighbouring countries with at least one 400 kV line (North Macedonia and Montenegro), with additional 220 kV lines in the case of Albania and Serbia.

The existing transmission development plan foresees a possibility to construct one more additional 400 kV interconnection line to Albania (Prizreni 4 – Skavica), but this is still highly unsure and very dependent on the future energy situation in both countries and the regional energy market. No other new cross-border projects are planned at this moment.

Concerning the new generation capacities, it is expected that a new coal fired unit of 450 MW may be put in operation replacing the existing three units in the TPP Kosova A. Other generation projects are related to a new pumped storage HPP with capacity larger than 200 MW and RES development, mainly in SPPs and WPPs, supported by a new battery energy storage system (BESS) of installed capacity equal to at least 35 MW. A new CCGT power plant is also under consideration but a national gas transmission network and a cross-border gas pipeline toward North Macedonia have to be developed firstly.

Table 7: Kosovar power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	Bus 1 (domestic)	Bus 2 (non-domestic)	From Kosovo* to	I_{max} (A)	S_n (MVA)	P_n (MW)
400	Kosova B	Komani	Albania	1900	1317	1185
400	Kosova B	Nis	Serbia	1900	1317	1185
400	Peja 3	Ribarevina	Montenegro	1900	1317	1185
400	Ferizaj 2	Skopje 5	N. Macedonia	1760	1218	1096
220	Prizreni 2	Fierze	Albania	790	300	270
220	Podujeva	Krusevac	Serbia	790	300	270
				ALL (existing situation)	5769	5192
PLANNED LINES						
-	-	-	-	-	-	-
				Existing+planned (short-time frame)	5769	5192
-	-	-	-	-	-	-
				Existing+planned (mid-time frame)	5769	5192
-	-	-	-	-	-	-
				Existing+planned (long-time frame)	5769	5192

The NTC values at the borders of Kosovo* have not been determined and agreed with neighbouring TSOs yet, since transmission capacities were allocated by the Serbian TSO (EMS) in the past. Indicative values for

Kosovar borders are shown in the following table according to values used in the PECI/PMI selection process in 2020. These values were in a range between 14 % and 27 % of the nominal capacities of the Kosovar interconnectors. If one observes all borders and all interconnectors over them, usage at the level of 23 % with respect to nominal capacity could be offered to the market participants under the PECI/PMI 2020 selection process assumptions. Since 14 December 2020, the TSO (KOSTT) operates as a control area in the control block AK (AL-KS). Since then, the NTC values for Albania have been changed from 250 MW to 400 MW.

Table 8: Indicative (maximum) NTC values at Kosovar borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
Kosovo* – Albania	250 (400*)	250 (400*)	1455
Kosovo* – Serbia	325	325	1455
Kosovo* – Montenegro	300	300	1185
Kosovo* – N. Macedonia	291	150	1096
TOTAL	**1166 (1316)**	**1025 (1175)**	**5192**

* since December 2020

The newest information suggests that NTCs of 400 MW could be allocated at the Montenegrin and North Macedonian borders and 600 MW at the Serbian and Albanian borders.

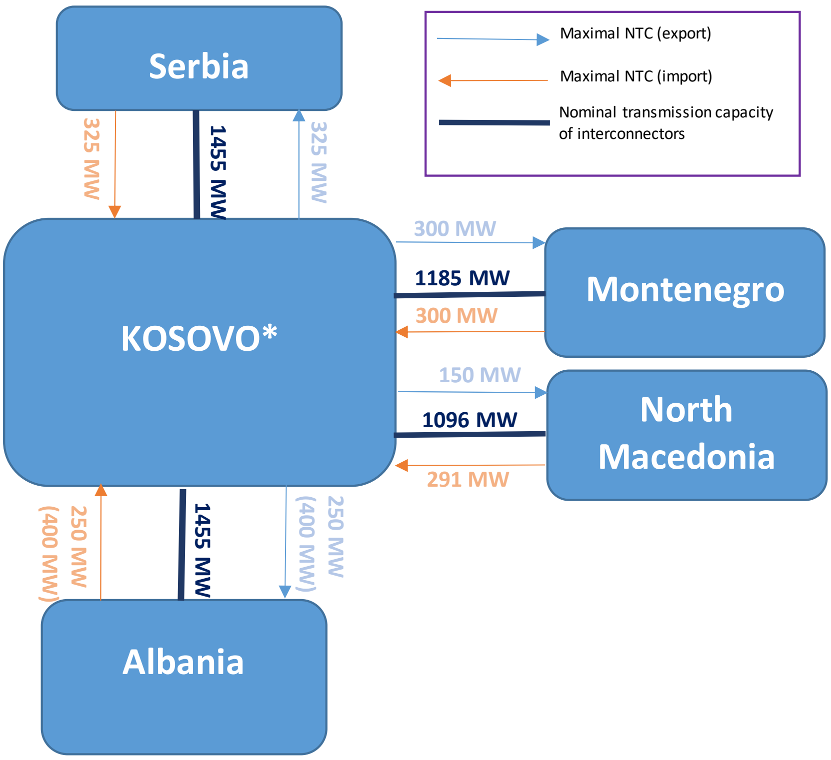

Figure 9: Nominal transmission capacity of the interconnectors at Kosovar borders and maximum NTC values

3.5 Moldova

Electricity consumption in Moldova fluctuates between 5 TWh and 6 TWh, with the peak load value reaching 1000 MW. Summer maximum load is significantly lower (~70% peak load), while minimum load typically drops down below 370 MW [10]. The large majority of annual electricity generation is provided by only one power plant (CERS Moldoveneasca, 2520 MW). There are three combined heat and power facilities (330 MW in total), two smaller hydro facilities and a negligible number of other RES. Total installed power is now 3008 MW in the generation facilities. Existing generation construction plans are directed mainly to existing power plant modernisation and possible development of renewables. National TYNDP [10] mentions new generation capacity of 1050 MW in the CHPs and additional 400 MW of capacity in RES (WPPs, SPPs) in the years to come.

At present, the Moldovan transmission system operates in parallel with the Ukrainian system and the IPS/UPS, but preparations to connect to the ENTSO-E system are underway (current plans suggest in 2023). Interconnection lines, which operate in normal operation mode, exist toward Ukraine, while lines toward Romania are normally out of operation and used only occasionally to feed parts of the country in an isolated mode of operation.

Figure 10: Transmission system of Moldova (existing situation) [10]
Source: Moldelecterica

The transmission network of Moldova operates under 400 kV, 330 kV and 110 kV voltage levels. It is meshed with the Ukrainian network over seven 330 kV lines[9] going from the southeast to the north of the country. The majority of the lines go into the Moldavskaia substation (MGRES) where the largest power plant is connected. Three 330 kV lines to Ukraine are operating radially and their nominal transmission capacity is restricted by apparent power of transformers at the end of the lines.

The northern connection with Ukraine goes toward the large hydro power plant Dnestrovskaia. Due to steady-state stability issues, the exchange of power between Ukraine and Moldova is restricted to cca. 800 MW, depending on the actual situation in the network and the number of units in operation in the main power plants. The 400 kV network includes one internal line (Moldavskaia – Vulcanesti) and one interconnection line to Romania (Vulcanesti – Isaccea)[10].

Table 9: Moldovan power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From Moldova to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
330	CERS Moldovenească	Novoodeskaia	Ukraine	1104	631	567
330	CERS Moldovenească	Usatovo	Ukraine	1104	631	567
330	CERS Moldovenească	Podolskaia	Ukraine	1489	852	767
330	Bălţi	HPP Dnestrovsk	Ukraine	1366	779	701
Radially operated lines						
330	CERS Moldovenească	Arţiz	Ukraine	-	325	293
330	Rîbniţa	Podolskaia	Ukraine	-	200	180
330	Rîbniţa	Podolskaia	Ukraine	-	400	360
400	Vulcăneşti	Isaccea	Romania	-	1212	1091
ALL (existing situation, without radially operated lines)					**2893**	**2602**
PLANNED LINES						
400 (B2B)[1]	Vulcăneşti	Isaccea	Romania	-	-	600
ALL new (short time-frame)					**0**	**600**
Existing+planned (short-time frame)					**2893**	**3202**
400[1]	Bălţi	Suceava	Romania	2117	1465	1319
Existing+planned (mid-time frame)					**4358**	**4521**
-	-	-	-	-	-	-
Existing+planned (long-time frame)					**4358**	**4521**

[1] expected to be in operation in the following 10 years (2022, 2027)

New interconnection projects considered by Moldelectrica are related to the synchronisation with ENTSO-E and linking up with the EU electricity market, which can be achieved by constructing new interconnectors in

[9] Connection to Ukraine has been also established over 11 110 kV lines.
[10] There are also 4110 kV lines between Moldova and Romania.

the direction of Romania. Two projects are considered in this respect, a back-to-back station and a link (600 MW) from Vulcanesti to Isaccea (with a new 400 kV line between SS Vulcanesti and SS Chisinau) and a 400 kV line between SS Balti and SS Suceava in Romania [10]. These investments were planned to be conducted till 2022 and 2027, respectively. New interconnection lines to Ukraine are under consideration at this stage but not included into the development plan (second line from Balti to the HPP Dnestrovskaia was considered in the past).

The maximum permitted exchange between Moldova and Ukraine was determined by Ukrenegro at the values of up to 800 MW (import from Ukraine) and 1200 MW (export to Ukraine), but highly depending on the operational situation in the network related to the lines under maintenance and number of units of the TPP MGRES and HPP Dnestrovskaia in operation at the moment. The maximum permitted import value from Ukraine to Moldova represents 31 % of the nominal transmission capacity of the interconnectors.

Table 10: Maximum exchanges at Moldovan borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
Moldova - Ukraine	800	1200	2602
Moldova – Romania[1]	-	-	-
TOTAL	**800**	**1200**	**2602**

[1] isolated mode of operation only

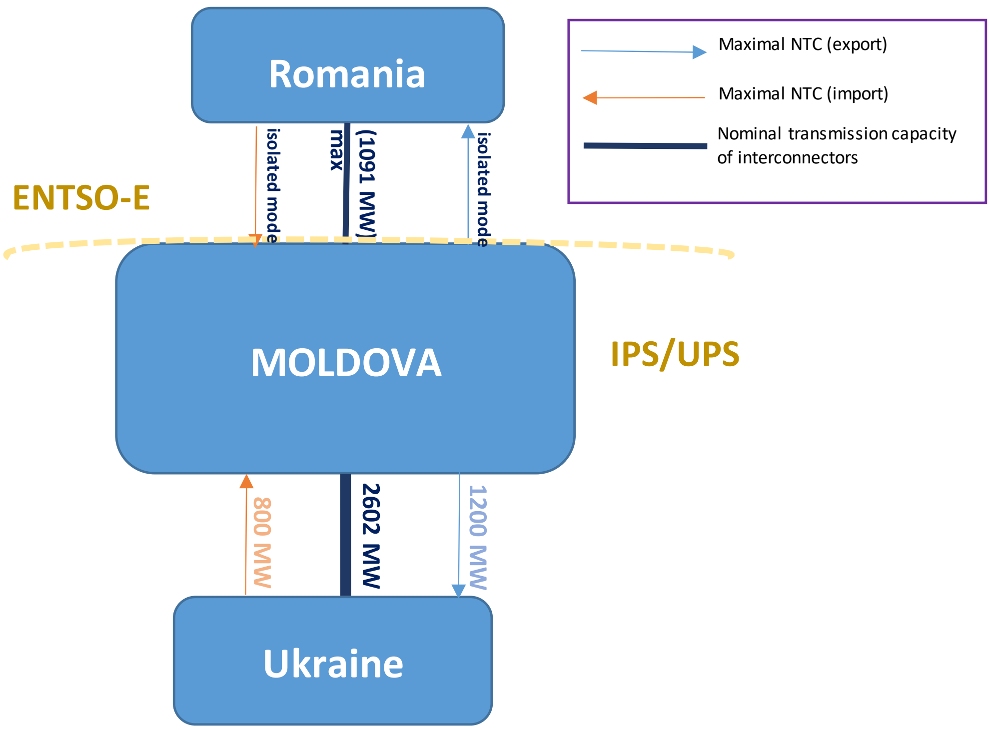

Figure 11: Nominal transmission capacity of the interconnectors at Moldovan borders and maximum NTC values

3.6 Montenegro

At present, electricity consumption in Montenegro is slightly above 3 TWh, dropping down from 4 TWh in the past due to decreased consumption of large industrial buyers. Consumers connected to the distribution network consume the largest portion of annual needs, but energy-intensive industrial consumers (aluminium and steel factories) account for a significant share of total consumption (cca. 20 %). Peak load reaches 700 MW, while summer maximum load is close to this value but with different geographical distribution of load over substations (high load in touristic areas near the Adriatic Sea). Minimum load may fall down to only 230 MW. It is forecast that peak load will reach close to 850 MW in the following ten years, with summer maximum load still lagging behind [11]. Electricity consumption should increase to 4.7 TWh during the same timeframe.

There are five power plants (total installed capacity of cca. 970 MW) connected to the transmission system, which are currently operational in Montenegro, one coal fired power plant, two hydro power plants and two wind parks. There are also a few small hydro facilities at the distribution network. Due to large dependence on the hydro power plants, the electricity balance strongly depends on hydrological conditions and the country may face a lack of energy, especially during summer months when consumption in the touristic regions is higher. On the contrary, when hydrology is favourable, especially during periods of lower consumption, the country may export electricity.

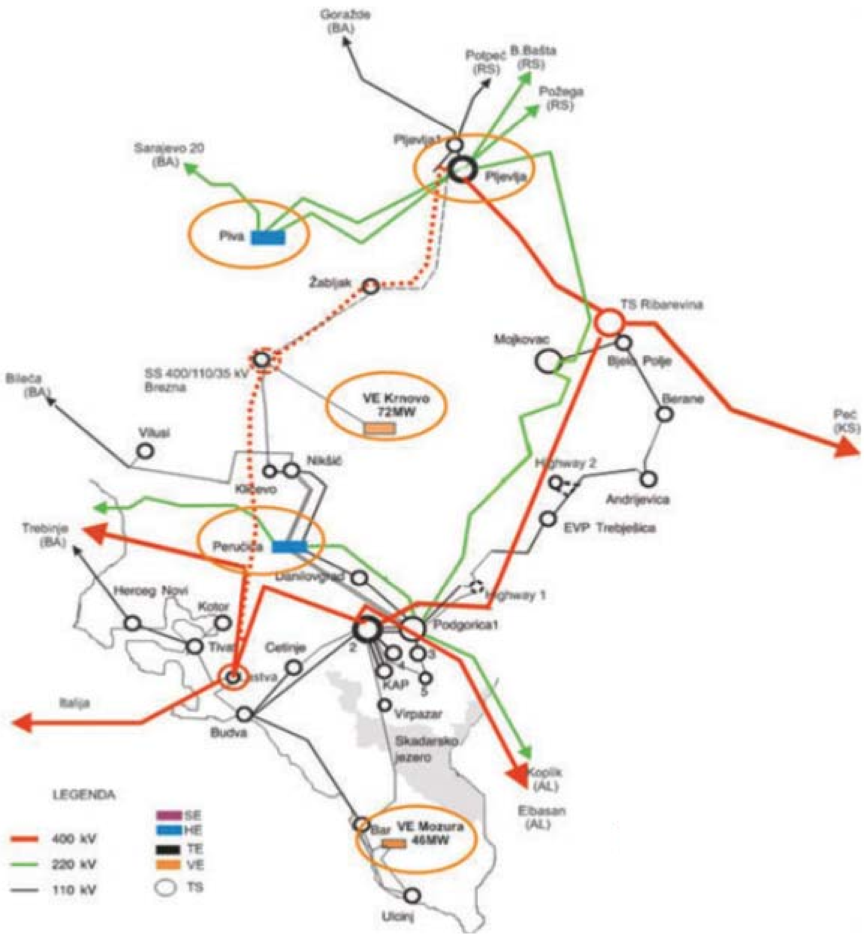

Figure 12: Transmission system of Montenegro (existing situation)
Source: CGES

The present generation expansion plan defines the possible construction of new hydro facilities (~250 MW), wind power plants (125 MW) and photovoltaics (250 MW). A second coal fired unit was planned (TPP Pljevlja 2) but recently this project has been abandoned, giving priority to modernisation of the existing unit.

The transmission system of Montenegro operates under 400 kV, 220 kV and 110 kV voltage levels. It is very well interconnected with surrounding countries (Bosnia and Herzegovina, Kosovo*, Serbia and Albania). The 600 MW HVDC link to Italy has recently been put into operation. The internal 400 kV ring will be finished in the near future, thus solving operational problems linked with the parallel operation of 400 kV and 220 kV lines in case of outages in the 400 kV network when some 220 kV lines are overloaded.

Table 11: Montenegrin power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From Montenegro to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
400	Ribarevine	Peja 3	Kosovo*	1900	1317	1185
400	Lastva	Trebinje	BiH	1920	1329	1196
400	Podgorica	Tirana 2	Albania	1920	1330	1197
500 (HVDC)	Lastva	Villanova	Italy	-	-	600
220	Podgorica	Koplik	Albania	790	300	270
220	HPP Piva	Sarajevo 20	BiH	960	365	329
220	HPP Perucica	Trebinje	BiH	790	301	271
220	Pljevlja	Bajina Basta	Serbia	720	274	247
220	Pljevlja	Pozega	Serbia	720	274	247
				ALL (existing situation)	**5490**	**5541**
PLANNED LINES						
-	-	-	-	-	-	-
				ALL new (short time-frame)	**0**	**0**
				Existing+planned (short-time frame)	**5490**	**5541**
400[1]	Pljevlja	B.Basta/Bistrica 1	Serbia	1920	1330	1197
				Existing+planned (mid-time frame)	**6820**	**6738**
400[1]	*Pljevlja*	*B.Basta/Bistrica 2*	*Serbia*	*1920*	*1330*	*1197*
				Existing+planned (long-time frame)	**6820** ***(8150)***	**6738** ***(7935)***

[1] expected to be in operation from 2026 (one circuit) and conditionally until 2029 (second circuit)

The network development plan defines a new interconnection line between Montenegro and Serbia (from the Pljevlja substation to the HPP Bajina Basta in Serbia) to be commissioned after 2025 but equipped with one circuit only, the second one may be installed several years after that. An HVDC link to Italy was initially designed to have transmission capacity of 1000 MW, constructed with one system of 600 MW and expanded to its planned capacity in the second phase. However, this project has been recently postponed and the new commissioning date is unknown. It is expected that the project will be continued after certain preconditions have been met.

Table 12: Indicative (maximum) NTC values at Montenegrin borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
Montenegro - Albania	400	441	1467
Montenegro - Bosnia and Herzegovina	500	500	1795
Montenegro – Serbia	300	200	493
Montenegro – Kosovo*	300	300	1185
Montenegro - Italy	600	600	600
TOTAL	**2100**	**2041**	**5541**

The indicative NTC values at the Montenegrin borders show that maximum capacity in a range between 28 % and 41 % of the nominal transmission capacities are offered to the market participants (excluding the HVDC link to Italy, that is assumed to be offered in its full capacity).

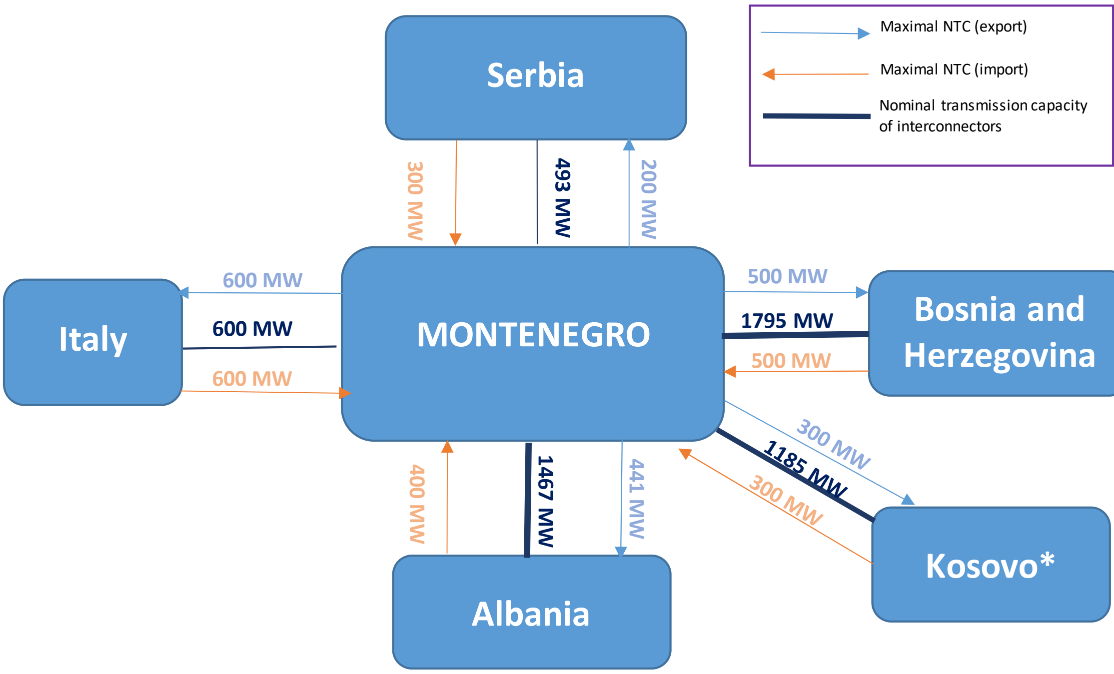

Figure 13: Nominal transmission capacity of the interconnectors at Montenegrin borders and maximum NTC values

3.7 North Macedonia

Typical annual electricity consumption in North Macedonia is around 6.5 TWh to 7 TWh, with the peak load value reaching 1500 MW. The generation mix consists of power plants with total installed capacity of 2070 MW, distributed over coal fired units (725 MW), one oil fired unit (198 MW), CHP units (287 MW), large hydro power plants (586 MW) and one wind power plant (36 MW), while there is a significant number of PV and small hydro units connected to the distribution network. Due to operational problems with coal fired units and dependency on hydrological conditions, North Macedonia relies on electricity imports supported by a number of interconnection lines towards all of their neighbours except Albania in present conditions (in 2023 this will change, as stated previously due to the expected operation of the new 400 kV line Bitola - Elbasan).

The transmission network operates under 400 kV and 110 kV voltage levels, with a 400 kV meshed network in the central part of the country and 110 kV network supplied at one local area from at least two substations 400/110 kV. Almost all substations 400/110 kV are connected with neighbouring transmission systems. There are five cross-border 400 kV lines to Kosovo*, Serbia, Bulgaria and Greece (two lines).

Electricity consumption in North Macedonia is forecasted to grow in the future up to 8.9 TWh to 9.5 TWh in 2030 and up to 10.3 TWh to 11.4 TWh in 2040.

Generation development plans in North Macedonia are mostly related to the integration of renewables (WPPs, SPPs and HPPs) and gradual phase-out of coal fired units till 2025. There are six WPPs projects awarded with a grid connection permit, together with one SPP project in the construction stage. The Macedonian draft NECP defines an 85 % RES share in the electricity production in 2030 (installed capacity of 2500 MW), mostly by hydro power plants but also PVs, WPPs and biogas/biomass facilities. Official input provided by MEPSO for ongoing regional studies suggests 940 MW of new production capacities until 2030 in different stages of realisation.

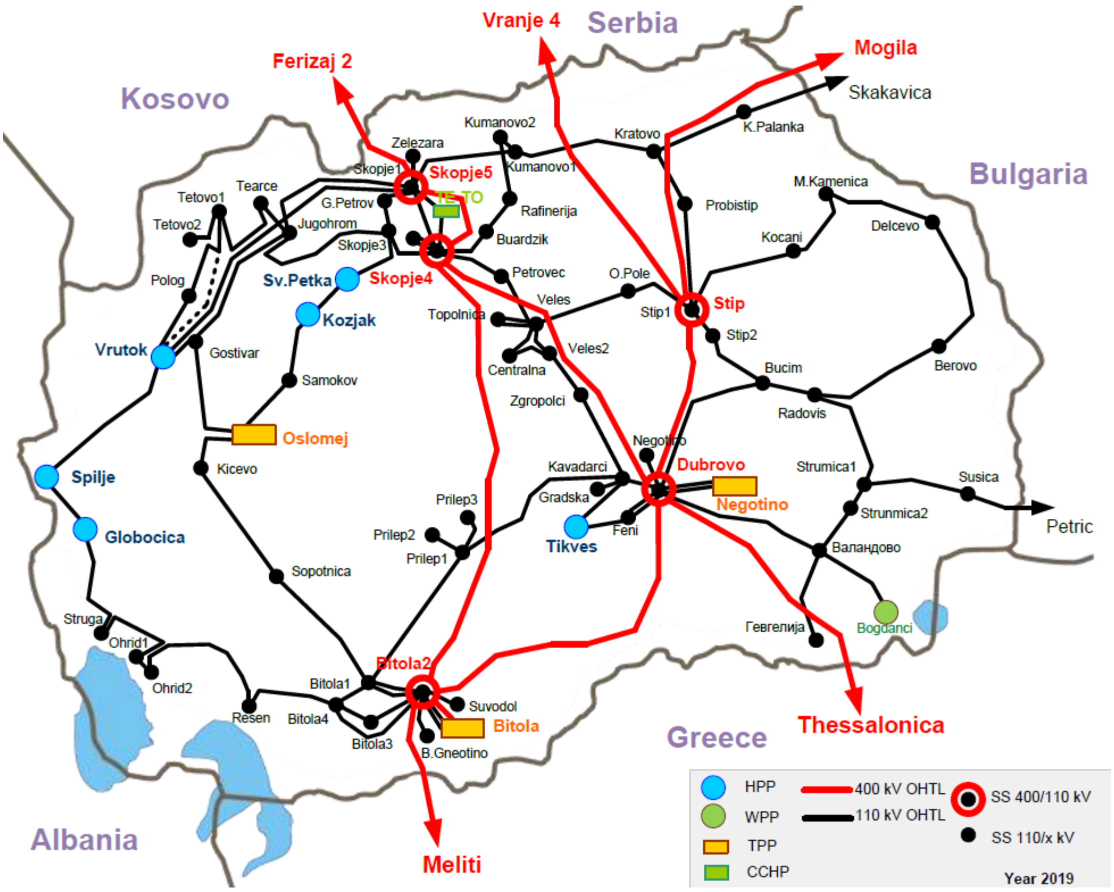

Figure 14: Transmission system of North Macedonia (existing situation)
Source: MEPSO

Table 13: North Macedonian power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From N. Macedonia to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
400	Skopje 5	Ferizaj 2	Kosovo*	1760	1218	1096
400	Stip	Cervena Mogila	Bulgaria	1760	1218	1096
400	Stip	Vranje	Serbia	1760	1218	1096
400	Dubrovo	Thessalonica	Greece	1243	860	774
400	Bitola 2	Meliti	Greece	1243	860	774
				ALL (existing situation)	**5374**	**4837**
PLANNED LINES						
400[1]	Bitola	Elbasan	Albania	1920	1330	1195
				ALL new (short time-frame)	**1330**	**1195**
				Existing+planned (short-time frame)	**6704**	**6032**
-	-	-	-	-	-	-
				Existing+planned (mid-time frame)	**6704**	**6032**
-	-	-	-	-	-	-
				Existing+planned (long-time frame)	**6704**	**6032**

[1] expected to be in operation from 2023

The NTC values related to North Macedonian borders are in a range between 14 % and 27 % of nominal transmission capacities meaning that a very small portion of transmission capacities is given to the market participants. By observing all borders and the sum of NTCs over them, only up to 22 % of the nominal transmission capacity on average is given to the market for the electricity import direction and up to 20 % for the electricity export direction.

Table 14: Indicative (maximum) NTC values at North Macedonian borders

Borders	**Import (MW)**	**Export (MW)**	**Nominal transmission capacity of interconnectors at the border (MW)**
N. Macedonia - Kosovo*	150	291	1096
N. Macedonia – Serbia	300	250	1096
N. Macedonia - Bulgaria	250	150	1096
N. Macedonia - Greece	350	300	1548
N. Macedonia - Albania	-	-	-
TOTAL	**1050**	**991**	**4837**

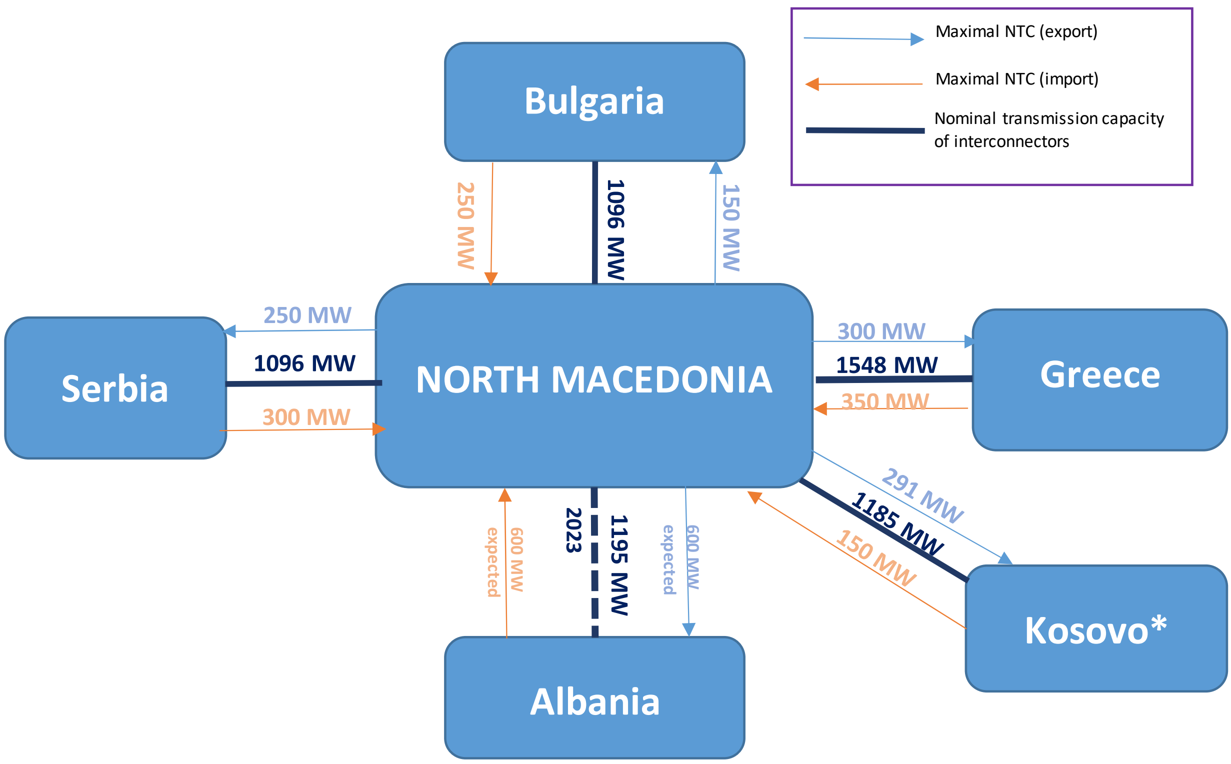

Figure 15: Nominal transmission capacity of the interconnectors at N. Macedonian borders and maximum NTC values

3.8 Serbia

Electricity consumption in Serbia is close to 34 TWh/year with the peak load values up to 5800 MW, regularly occurring during wintertime, with summertime maximum load value in the range of 70% of the peak load and minimum load value in the range of 36% of the peak load. National TYNDP [14] predicts that peak load may reach a value between 7.3 GW and 7.6 GW in the following ten years (including Kosovo*). Electricity consumption may rise up to 45 TWh/year in 2050 according to the PECI/PMI selection process 2020 and data delivered by the Serbian TSO (EMS).

The largest Serbian electricity producer EPS owns 7 TPPs and CHP facilities (4623 MW), including two large coal fired power plants and around 20 hydro power plants (2981 MW), which makes total installed capacity of approximately 8.3 GW, together with independent producers from WPPs of total installed capacity of 373 MW (in 2019) and distributed generation of 160 MW. Serbia is able to produce electricity to cover domestic consumption in normal circumstances, but faces a problem of ageing power plants and their necessary modernisation and the global question of environmentally friendly electricity production.

The transmission network operates under 400 kV, 220 kV and 110 kV voltage levels with almost 10 000 kilometres of lines, including 12 400 kV and 220 kV cross-border lines (7 400 kV lines + 1 line (2x400 Kv) and 4 220 kV lines) connecting Serbia with all neighbouring countries (Croatia, Hungary, Romania, Bulgaria, North Macedonia, Kosovo*, Montenegro and Bosnia and Herzegovina, 8 borders in total). Due to its geographical position, the Serbian transmission system is obviously the most important infrastructural part of the regional electricity market in the Balkans, which can help create the necessary preconditions for more intensive electricity trade in the region. At the moment, the 400 kV double line Pančevo – Resiţa is not in parallel operation as it is not completed on the Romanian side.

Figure 16: Transmission system of Serbia and Kosovo (existing situation with planned reinforcements)* [11]
Source: EMS

The 400 kV transmission network is meshed in the central and eastern part of the country (area between Belgrade, Nis and the HPP Djerdap), with radial lines toward the Vojvodina region in the north and the southern part of Serbia. The western part of the country is presently supplied over 220 kV lines. The largest generation facilities are connected to the 400 kV network but there is a significant number of 220 kV connections, including with the large pumped storage hydro power plant Bajina Basta (614 MW).

There is at least one 400 kV line that may carry up to 1100 MW connecting Serbia with all of its neighbouring countries at the moment. In 2019, approximately 5.2 TWh entered the network through interconnections and 3.7 TWh exited the network, meaning that transits over the Serbian transmission network were in a range of 10% compared with the total electricity that entered the system from different sources (domestic producers, distribution network and interconnections).

[11] NOTE: This EMS figure includes Kosovo*'s system in grey.

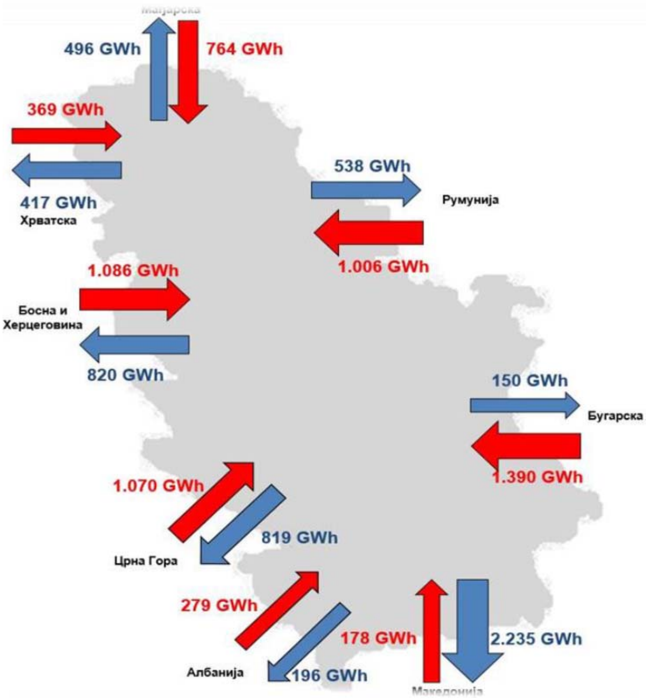

Figure 17: Exchanges over Serbian cross-border lines in 2019[12]
Source: EMS [15]

The present generation development plans in Serbia include the intention of state owned EPS to construct a new 350 MW coal fired unit at the Kostolac site and to revitalize several thermal (TENT A, Kostolac A) and hydro power plant units (Djerdap 1, Djerdap 2, Zvornik, Potpec), as well to install 166 MW of RES. There are also a number of projects related to the construction of WPPs by private investors and new CHP power plants. The Serbian TSO estimated that up to 4500 MW of new installed capacity could be connected to the transmission grid in the following ten years according to the 10-year development plan 2021- 2030.

The transmission development plan, with respect to the new cross-border lines, defines construction of the new 400 kV lines toward Bosnia and Herzegovina (Bajina Basta – Visegrad) and Montenegro (Bajina Basta – Pljevlja) until 2026. Preconditions for these lines are internal 400 kV network reinforcements including a new double-circuit line (2x400 kV) Obrenovac – Bajina Basta and the construction of a 400 kV switchyard at Bajina Basta (currently there is a 220 kV switchyard). In the long-term, there are several projects considered by EMS (new 400 kV interconnections toward Croatia, Romania, Bulgaria and Hungary, instalment of the second 400 kV circuit to the new line Bajina Basta – Pljevlja and Bajina Basta – Visegrad, in order to create new 400 kV lines Pozega – Pljevlja and Pozega - Vardiste), but it seems that the reinforced interconnection to Romania is their main focus (North CSE corridor including revitalisation of the Djerdap – Portile de Fiere 400 kV line into a double-system circuit line, a new internal 400 kV line Cibuk – Belgrade West and a new SS 400/110 kV Belgrade West).

[12] NOTE: This EMS figure includes the territory of Kosovo* as part of Serbia. It refers to exchanges over the border with Albania and partially over the borders of Montenegro and North Macedonia.

Table 15: Serbian power interconnection lines (existing and planned)

Voltage level (kV)	Bus 1 (domestic)	Bus 2 (non-domestic)	From Serbia to	I_{max} (A)	S_n (MVA)	P_n (MW)
EXISTING LINES						
400	Sremska Mitrovica	Ernestinovo	Croatia	1920	1329	1196
400	Sremska Mitrovica	Ugljevik	BiH	1920	1329	1196
400	Nis	Kosova B	Kosovo*	1900	1317+	1185
400	Vranje	Stip	N. Macedonia	1760	1218+	1096
400	Nis	Sofia	Bulgaria	1920	1329	1196
400	Djerdap	Portile de Fiere	Romania	1840	1273	1146
400	Subotica	Sandorfalva	Hungary	1920	1329	1196
220	Vardiste	Visegrad	BiH	790	301+	271
220	Bajina Basta	Pljevlja	Montenegro	720	274+	247
220	Pozega	Pljevlja	Montenegro	720	274+	247
220	Krusevac	Podujeva	Kosovo*	790	300+	270
				ALL (existing situation)	**10273**	**9245**
PLANNED LINES						
2x400[1]	Pancevo	Resica	Romania	3844	2660	2394
				ALL new (short time-frame)	**2660**	**2394**
				Existing+planned (short-time frame)	**12933**	**11639**
400[2]	Bajina Basta	Visegrad	BiH	1920	1329	1196
400[2]	Bajina Basta	Pljevlja	Montenegro	1920	1329	1196
				Existing+planned (mid-time frame)	**15591**	**14032**
400[3]	Djerdap	Portile de Fiere	Romania	3680	2546	2291
				Existing+planned (long-time frame)	**16864**	**15177**

expected to be in operation: [1] from 2024 (already constructed on Serbian side); [2] from 2026; [3] from 2030
+ value restricted by neighbouring TSO (compared to data delivered by EMS)

Maximum NTC values at Serbian borders are up to 70 % of the nominal transmission capacity of interconnectors over observed borders. The highest usage ratio refers to interconnections toward Romania and Hungary, while the lowest ratio is related to the borders with Bulgaria (25 %). On average, EMS gives up to 40 % of nominal transmission capacity of all interconnectors to the market participants[13].

[13] The response of EMS during the data garthering phase of this study was the following: "Regarding the calculation and harmonization of the NTC, it is important to emphasize that EMS regularly calculates higher values compared to the adjacent TSOs. In 2020 alone, this discrepancy reached an average of 700 MW (per direction for all borders) of which 500 MW refer only to two borders with EU TSOs! If EMS values had been adopted, EMS would allocate almost 50% of the nominal transmission capacity of the interconnectors.
The second reason for NTC limitations is within the Serbian network and is mainly related to the weak 220 kV network in the western and central part of the country, with bottlenecks affecting the borders with Bosnia and Herzegovina, Montenegro and Kosovo*. These limitations can only be removed by extending the grid to 400 kV. In the meantime, NTCs could be expanded only by applying regional cross-border re-dispatching and a cost-sharing mechanism.

Table 16: Indicative (maximum) NTC values at Serbian borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
Serbia – Croatia	600	600	1196
Serbia – BiH	600	600	1467
Serbia - Kosovo*[1]	325	325	1455
Serbia – Montenegro	200	300	493
Serbia - N. Macedonia	250	300	1096
Serbia - Bulgaria	350	300	1196
Serbia - Romania	800	800	1146
Serbia - Hungary	700	800	1196
TOTAL	**3825**	**4025**	**9245**

[1] estimated value based on the PECI/PMI selection process (currently no capacity allocation at the border)

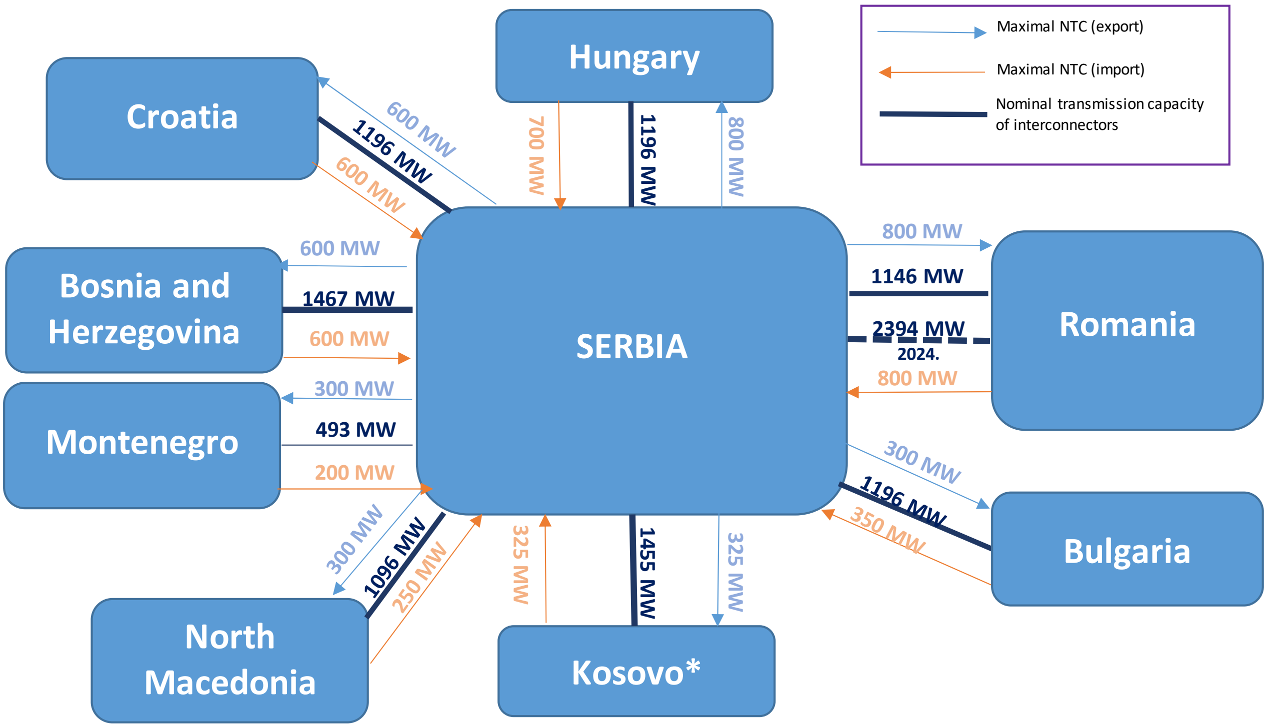

Figure 18: Nominal transmission capacity of the interconnectors at Serbian borders and maximum NTC values

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Unfortunately, this cannot be introduced until the official RCC region is established for the WB6 region, in accordance with CE SAFA rules and upon a decision by the relevant EU bodies."

3.9 Ukraine

Electricity consumption in Ukraine is 144 TWh/year (gross) and 117 TWh/year (net), which is larger than the annual electricity consumption of all other eight Contracting Parties together. The peak load occurs during winter months in the amount of 24 GW. According to the forecast received through the PECI/PMI selection process in 2020, expectations are that electricity consumption will rise up to 158.5 TWh/year in 2030 and 180.3 TWh/year in 2050. The generation mix consists of nuclear units (13.8 GW[14]), thermal units, mostly coal fired (21.8 GW), hydro power plants (4.8 GW in run-of-river and 1.5 GW in storage HPPs), combined heat and power production facilities (6 GW), solar power plants (4.9 GW), wind power plants (1.1 GW) and biofuel plants (2 GW), that makes the total installed capacity of the power production facilities of 54.2 GW.

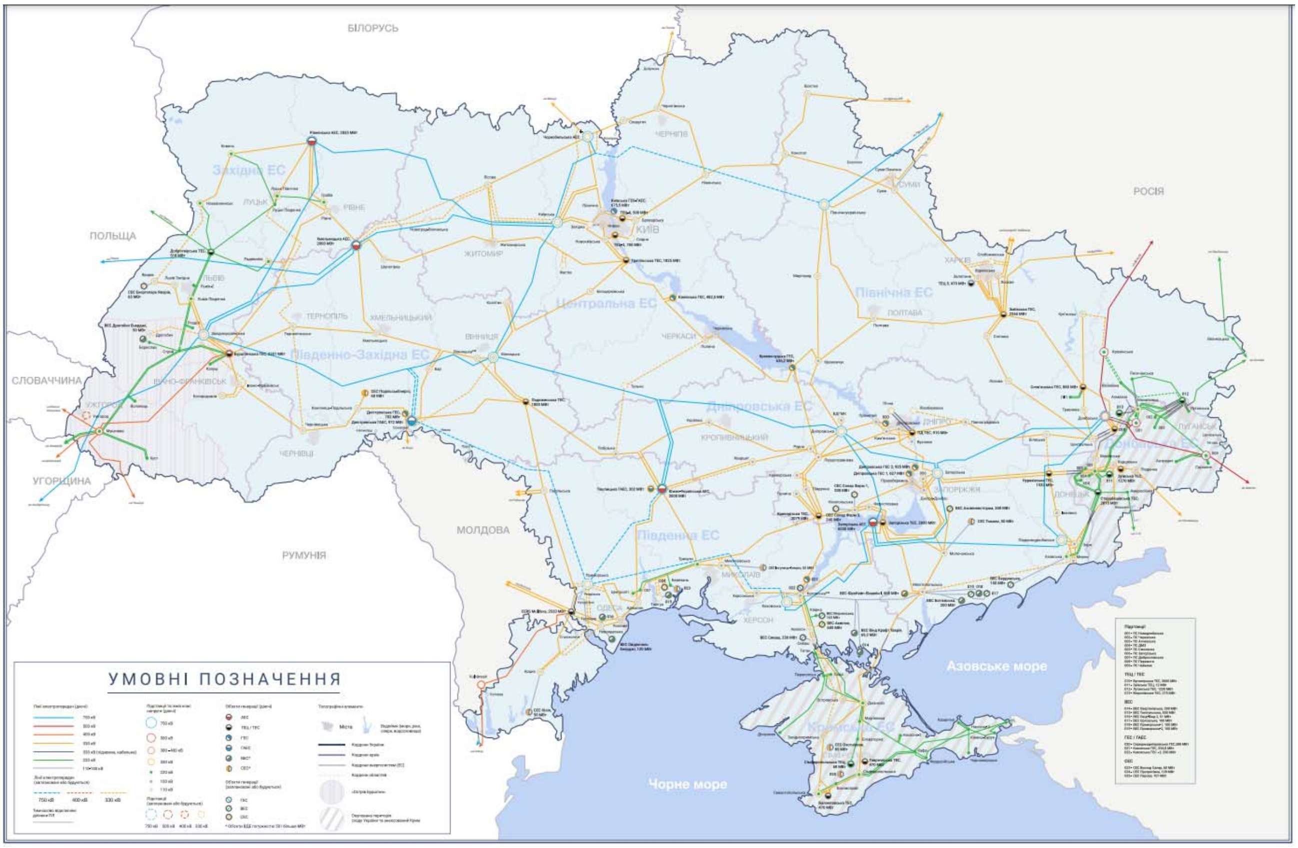


Figure 19: Transmission system of Ukraine
Source: Ukrenegro

At the moment, the generation expansion plan in Ukraine is still highly uncertain. The country is faced with technical issues which need to be solved in order to establish interconnection with ENTSO-E and at the same time there are growing initiatives to phase out coal fired power plants (scheduled in the time range between 2033 and 2043), without having a viable alternative to replace their production. That is the reason why the

[14] 4 nuclear power plants, 15 units

development of new nuclear units is again under consideration. The development of renewables, mainly solar and wind facilities, is growing.

The majority of the transmission grid is related to the 750 kV (4400 km), 330 kV (~13000 km) and 220 kV (~3000 km) lines, but there are facilities operating under 800 kV (~100 km), 500 kV (~375 km) and 400 kV (~340 km). The 750 kV network is the backbone of the grid while regional transmission is mainly performed at the 330 kV voltage level. The national transmission grid is administratively divided into six regional grids (Central, Dnieper, Northern, Southern, Western and South-Western) and two temporarily uncontrolled regional grids (Crimea and Donbass). Part of the Western region called Burshtyn island is electrically connected to the ENTSO-E system, while the rest of the grid operates synchronously with the IPS/UPS system. The plan is to permanently synchronize the operation of the whole grid with the European system and to disconnect from the IPS/UPS system at the latest in 2023. Burshtyn island has a peak load of ~1 GW and generation facilities of 2.5 GW (the majority in one TPP, 200 MW in one CHPP and 27 MW in one HPP).

Ukraine is interconnected with Russia, Moldova, Belarus, Poland, Slovakia, Hungary and Romania, having 8 cross-border connections (330 kV and above) with Russia and two with Belarus, while Burshtyn island has interconnectors toward Slovakia (one 400 kV line), Hungary (one 750 kV line, one 400 kV line and two 220 kV lines) and Romania (one 400 kV line; one 750 kV line is permanently out of operation). There are also seven 330 kV interconnections with Moldova. Ukraine shares two interconnectors with Poland (one 750 kV line and one 220 kV line) but one is temporarily out of operation (750 kV line) and one is used radially (220 kV).

According to Ukrenergo, power exchanges between Ukraine and its neighbouring countries are limited to the NTC values shown in the following table.

Table 17: Indicative (maximum) NTC values at Ukrainian borders

Borders	Import (MW)	Export (MW)	Nominal transmission capacity of interconnectors at the border (MW)
Ukraine - Poland[1]	-	235	297
Ukraine – Slovakia	600	600	979
Ukraine – Hungary	900	800	3277
Ukraine – Romania	400	400	1151
Ukraine – Moldova	1200	800	2602
Ukraine – Russia	2200	1800	7929
Ukraine – Belarus	900	900	1935
TOTAL	**6200**	**5535**	**18170**

[1] isolated mode of operation

The following table presents all interconnection lines between Ukraine and its neighbouring countries, with data about nominal transmission capacities of lines toward countries operating (or will operate like Moldova) with continental Europe and toward the IPS/UPS system (Russia and Belarus). At the moment, nominal transmission capacity of all lines connecting Ukraine to ENTSO-E is 5700 MW, or together with Moldova 6800 MW. Nominal transmission capacity of all existing lines between Ukraine and ENTSO-E plus Moldova is approximately 8.3 GW, while nominal transmission capacity of all lines between Ukraine and Russia/Belarus is slightly larger (10 GW). In the future, Ukrenegro plans to reinforce interconnections with EU countries (Slovakia, Romania and Poland) in order to increase electricity transfer possibilities between the domestic and the pan-European electricity market. Of special interest are projects related to revitalisation/reinforcement of the existing 750 kV and 400 kV lines between Ukraine, Slovakia, Romania and Poland. If these projects are going to be realized, nominal transmission capacity between Ukraine and ENTSO-E + Moldova will be increased for an additional 4500 MW, reaching the total value of 13 GW.

Table 18: Ukrainian power interconnection lines (existing and planned)

EXISTING LINES						
Voltage level (kV)	**Bus 1 (domestic)**	**Bus 2 (non-domestic)**	**From Ukraine to**	**I_{max} (A)**	**S_n (MVA)**	**P_n (MW)**
750	Zakhidnoukrainska	Szabolcsbaka	Hungary	2002	2598	2338
400	Mukacheve	Velke Kapushany	Slovakia	1572	1088	979
400	Mukacheve	Szabolcsbaka	Hungary	801	554	499
400	Mukacheve	Roshior	Romania	1848	1279	1151
330	Novoodeskaia	CERS Moldovenească	Moldova	1104	631	567
330	Usatovo	CERS Moldovenească	Moldova	1104	631	567
330	Podolskaia	CERS Moldovenească	Moldova	1492	852	767
330	HPP Dnestrovsk	Bălţi	Moldova	1364	779	701
220	Mukacheve	Tiszalok	Hungary	641	244	220
220	Mukacheve	Kishvarda	Hungary	641	244	220
220	Dobrotvirska TPP	Zamost	Poland	867	330	297
750	Pivnichnoukrainska	Kurska NPP	Russia	771	1000	900
500	Donbaska	Kremenskaya	Russia	1965	1700	1530
500	Donska	Kremenskaya	Russia	1965	1700	1530
330	Losieve	Shebiekine	Russia	1506	860	774
330	Sumy pivnichna	Kurska NPP	Russia	1752	1000	900
330	Shostka	Kurska NPP	Russia	1489	850	765
330	Zmiivska TPP	Valuiky	Russia	1489	850	765
330	Zmiivska TPP	Bielhorod	Russia	1489	850	765
330	Chornobylska NPP	Mozyr	Belarus	2014	1150	1035
330	Chernihivaska	Homel	Belarus	1752	1000	900
Radially operated lines						
330	Arţiz	CERS Moldovenească	Moldova	1492	852	767
330	Podolskaia	Rîbniţa	Moldova	1001	572	514
330	Podolskaia	Rîbniţa	Moldova	1001	572	514
ALL (existing situation, without radially operated lines)					**20190**	**18170**
ENTSO-E + Moldova					**9230**	**8306**
IPS/UPS					**10960**	**9864**
PLANNED LINES						
400[1]	Mukacheve	Velke Kapushany	Slovakia	1590	1100	990
ALL new (short time-frame)					**1100**	**990**
ENTSO-E + Moldova (short-time frame)					**9242**	**8317**
IPS/UPS (short-time frame)					**10960**	**9864**

PLANNED LINES						
Voltage level (kV)	Bus 1 (domestic)	Bus 2 (non-domestic)	From Ukraine to	I_{max} (A)	S_n (MVA)	P_n (MW)
				Existing+planned (short-time frame)	20202	18181
-	-	-	-	-	-	-
				Existing+planned (mid-time frame)	20202	18181
400[2]	Mukacheve	Velke Kapusany	Slovakia	1590	1100	990
750/2x400[3]	Uzhnoukrainska	Isaccea	Romania	2890	2000	1800
750[4]	Khmelnytska NPP	Rzeszow	Poland	2818	1950	1755
				Existing+planned (long-time frame)	25252	22726
				ENTSO-E + Moldova (long-time frame)	14292	12862
				IPS/UPS (long-time frame)	10960	9864

[1] existing line revitalisation, expected until 2023

[2] upgrade of the existing/revitalised line with the second circuit, expected until 2030.

[3] revitalisation of the 750 kV OHL Uzhnoukrainska NPP - Isaccea on the route from the Uzhnoukrainska NPP to the new 750 kV SS “Prymorska” site; construction of the 750/400 kV substation “Prymorska”; revitalization of the 750 kV OHL Uzhnoukrainska NPP-Isaccea on the route from the new 750 kV substation “Prymorska” to the 750 kV substation Isaccea by construction of a double-circuit 400 kV overhead line, expected until 2029.

[4] revitalisation of the existing line, time schedule still unknown.

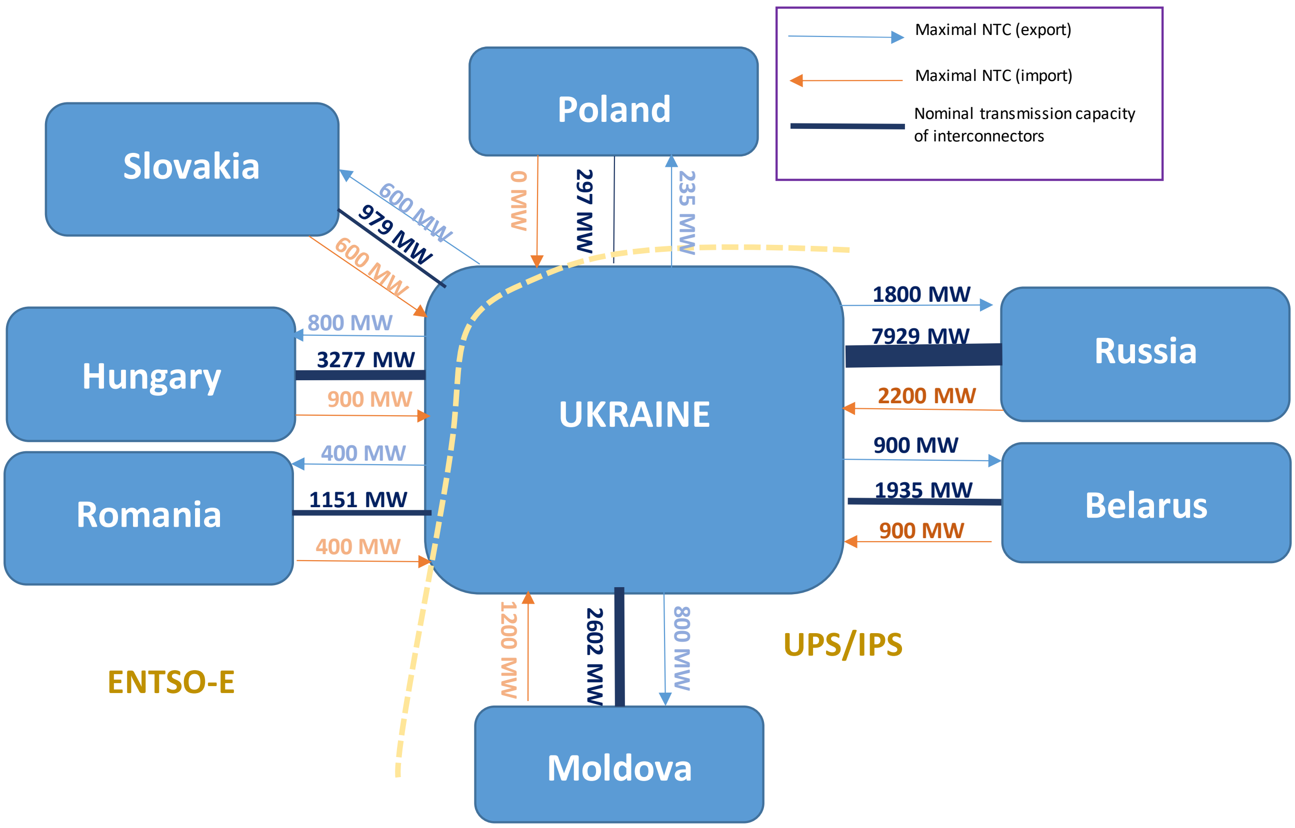


Figure 20: Nominal transmission capacity of the interconnectors at Ukrainian borders and maximum NTC values (maximum permitted exchanges)

3.10 Overview of Contracting Parties' existing levels of interconnectivity and their development plans

The cross-border lines in the Energy Community Contracting Parties today have transmission capacities significantly above the majority of EU Member States, in relation to their peak load and installed generation capacities. This is valid for all of them although Ukraine, Moldova and Georgia face restrictions related to the usage of their cross-border capacities due to the different synchronous areas around them, which does not allow them to use all interconnectors at the same time without limitations. All power interconnections are AC type except the ones connecting Georgia with Turkey and Montenegro with Italy which are HVDC, meaning that further limitations could be caused by the power flows in the networks which prevent all interconnections in one country to be fully utilized due to the physical electricity flow in meshed systems. It also seems that a large number of interconnectors might be overdesigned due to different reasons, including failed expectations about future consumption growth at a time when interconnectors were being planned many years ago. Moreover, it seems that internal transmission networks were designed in a way that is not fully compatible with the nominal transmission capacities of interconnectors. That is probably the main reason why the NTC values are significantly smaller than nominal transmission capacities of the interconnectors, as shown in the following figure. The TSOs' concerns about the security of supply may be another reason for under-usage of the interconnectors, a topic that is worth exploring further by determining an optimum point between expected benefits brought by more intensive market activities on the one side and the security of supply and network operation safety on the other side.

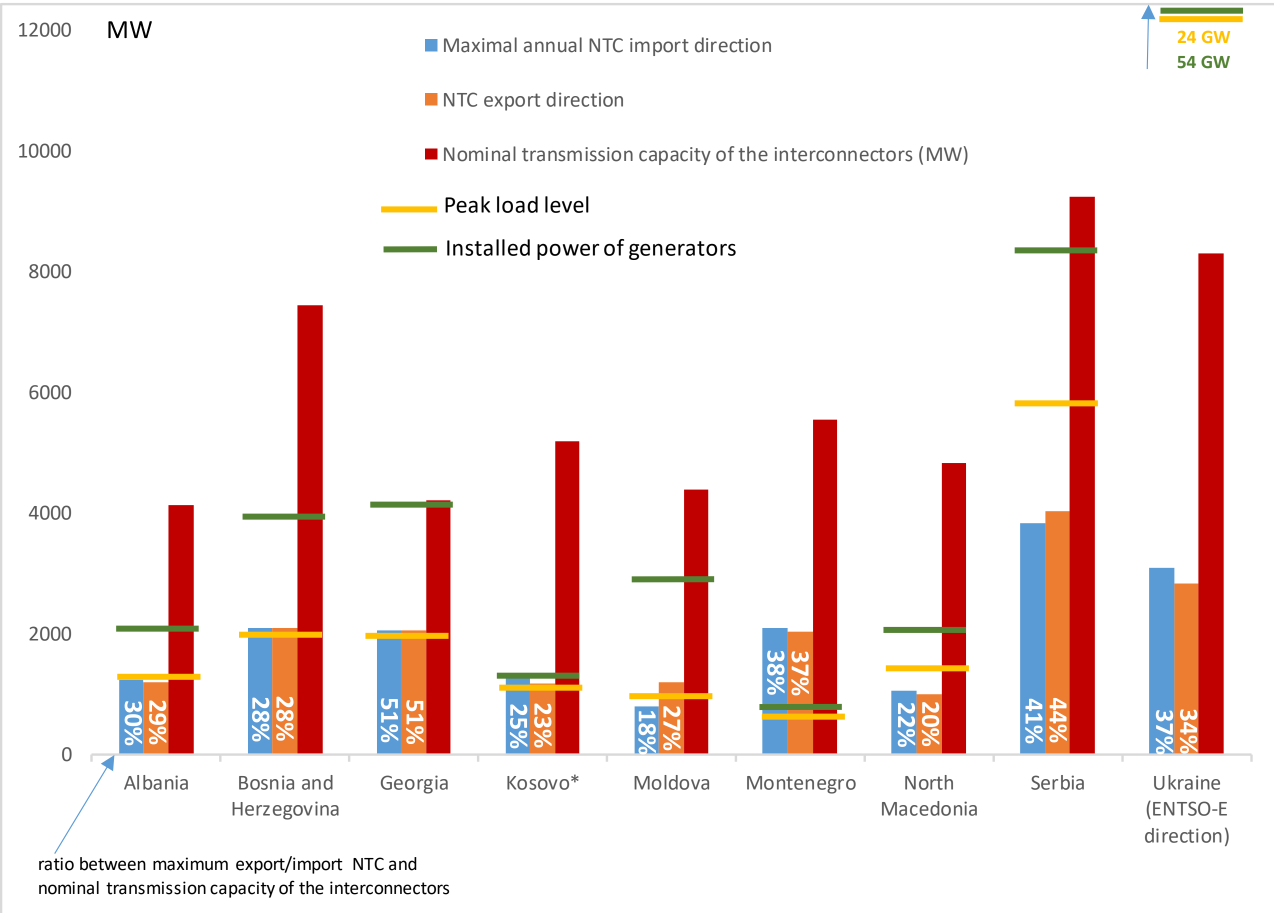


Figure 21: Maximum NTC values today and nominal transmission capacity of interconnectors in each CP

Interconnectors in the Contracting Parties operate mostly under 400 kV and 220 kV voltage levels, including 330 kV in the eastern countries. A 400 kV line is normally able to transmit cca. 1000 MW of power (under stable operating conditions), while this is reduced for a 220 kV line to cca. 250 MW to 300 MW. Having in mind that the majority of the CPs, except Ukraine and Serbia, have quite low electricity demand and related peak load, it is obvious that 400 kV interconnectors may play a dominant role in the total power supply of a country. This is valid also for electricity exports since installed generation today is also relatively small.

The present NTC values, defined by and agreed between different CP TSOs, are mostly lower than 30 % of the nominal transmission capacity of interconnectors. Since the previous figure shows maximum NTC values, it becomes evident that during a significant part of the year the transmission capacities offered to the market players are even much smaller than 30 % of the nominal transmission capacities of the interconnectors, therefore resulting in non-compliance with the 70 % target that has to be fulfilled on an hourly basis once it becomes legally binding for the CPs. This practice, being justified or not, restricts market activities in the region and causes higher electricity prices due to the incurred congestion costs (collected by the TSOs). The present situation also allows incumbent producers to continue exerting significant market power and economically unviable generation capacities to keep operating although they cannot compete at the market. This raises compliance issues and shall be monitored closely by national regulatory authorities.

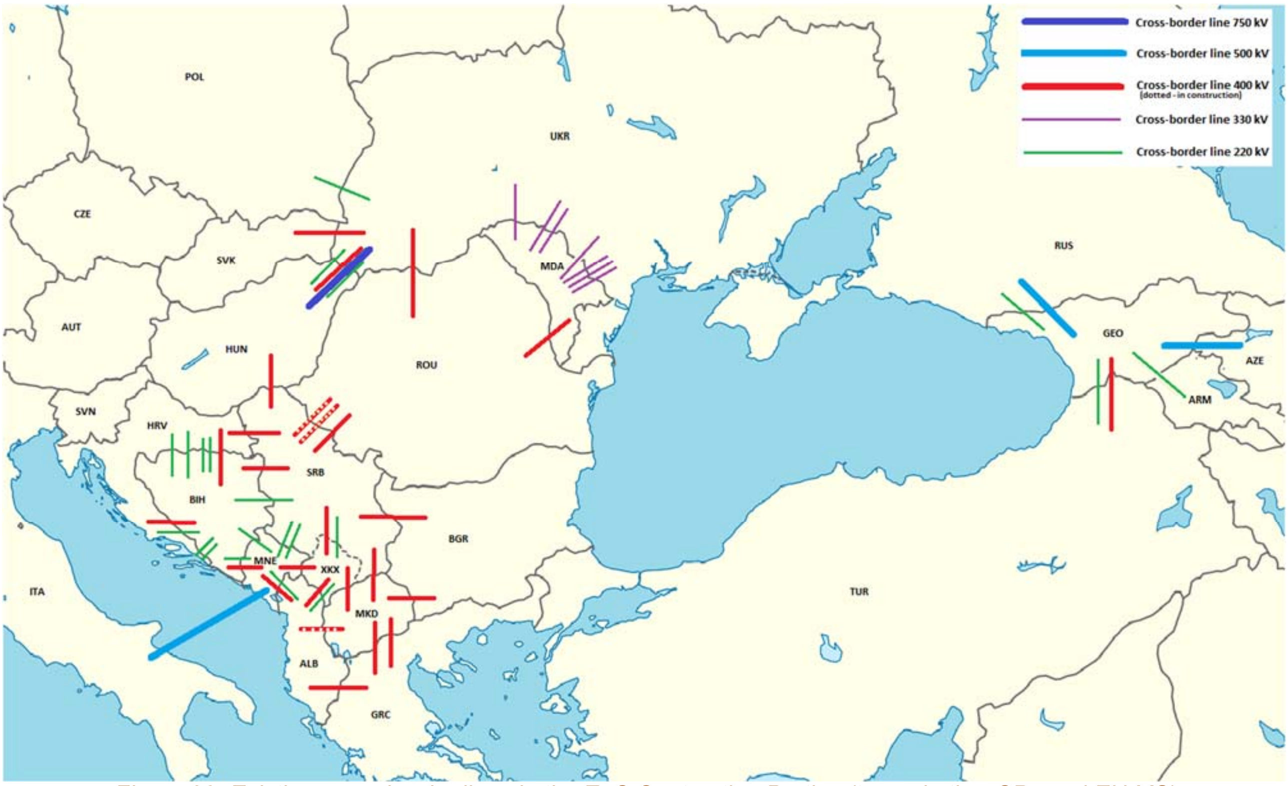


Figure 22: Existing cross-border lines in the EnC Contracting Parties (toward other CPs and EU MS)

As shown in the previous figure, the WB6 power systems are significantly interconnected, with many 400 kV lines connecting the CPs. The same rings true for interconnections with the EU Member States like Croatia, Hungary, Romania, Bulgaria, Greece and Italy. All CPs in the WB6 area are connected to at least one EU Member State except Kosovo* due to its geographical position (it does not share a border with any EU Member State). Eastern countries like Ukraine and Moldova have interconnectors toward the EU Member States (Poland, Slovakia, Hungary, Romania) but they are used in a limited way due to the different synchronous systems in place today. The only Contracting Party that does not have a connection with other CPs and EU Member States is Georgia, due to its distant geographical location.

By observing the ratio between nominal transmission capacity of the interconnectors and the peak load or ratio between nominal transmission capacity of the interconnectors and the total installed power of the production facilities, one may conclude that Montenegro has the highest ratios among the CPs, although these ratios are also very high for Albania, Bosnia and Herzegovina, Kosovo*, Moldova, North Macedonia and Serbia. Georgia has slightly limited ratios in comparison with other countries as it is dependent on the maximum permitted loading of its existing 500 kV lines. Ukraine has the lowest ratios but still well above the majority of EU countries (Ukraine is the only country having both ratios below 100 %).

Table 19: Nominal transmission capacities of the interconnectors, peak load and installed power

Country	Nominal transmission capacity of interconnectors (MW)*				Peak load-existing (MW)**	Total installed power (MW)
	existing situation	short-term future	mid-term future	long-term future		
Albania	4137	5352.3	5352.3	5352	1400	2193
Bosnia and Herzegovina	7448	7448	8644	9840	2000	4080
Georgia	3970 *2110******	5030 *3170******	6910 *4520******	7910 *5520******	2000	4246
Kosovo*	5192	5192	5192	5192	1200	1438
Moldova	2602	3202	4521	4521	1000	3008
Montenegro	5541	5541	6738	7935	700	874
North Macedonia	4837	6052	6052	6052	1500	2070
Serbia	9245	11639	14032	15177	5800	8300
Ukraine	18170	18181	18181	22726	24000	54200

* after reducing total capacity in MVA because of possible reactive power flows
** rounded value
*** by using GSE restrictions on the 500 kV lines to Russia and Azerbaijan

Table 20: Ratio between nominal transmission capacities of interconnectors and peak load/installed power of generators

Country	Ratio	
	Nominal transmission capacity of interconnectors /peak load	Nominal transmission capacity of interconnectors/installed power of generators
Albania	296%	189%
Bosnia and Herzegovina	372%	183%
Georgia	200% (106%*)	94% (50%*)
Kosovo*	433%	361%
Moldova	260%	87%
Montenegro	792%	634%
North Macedonia	322%	234%
Serbia	159%	111%
Ukraine	76%	34%

* by using GSE restrictions on the 500 kV lines to Russia and Azerbaijan

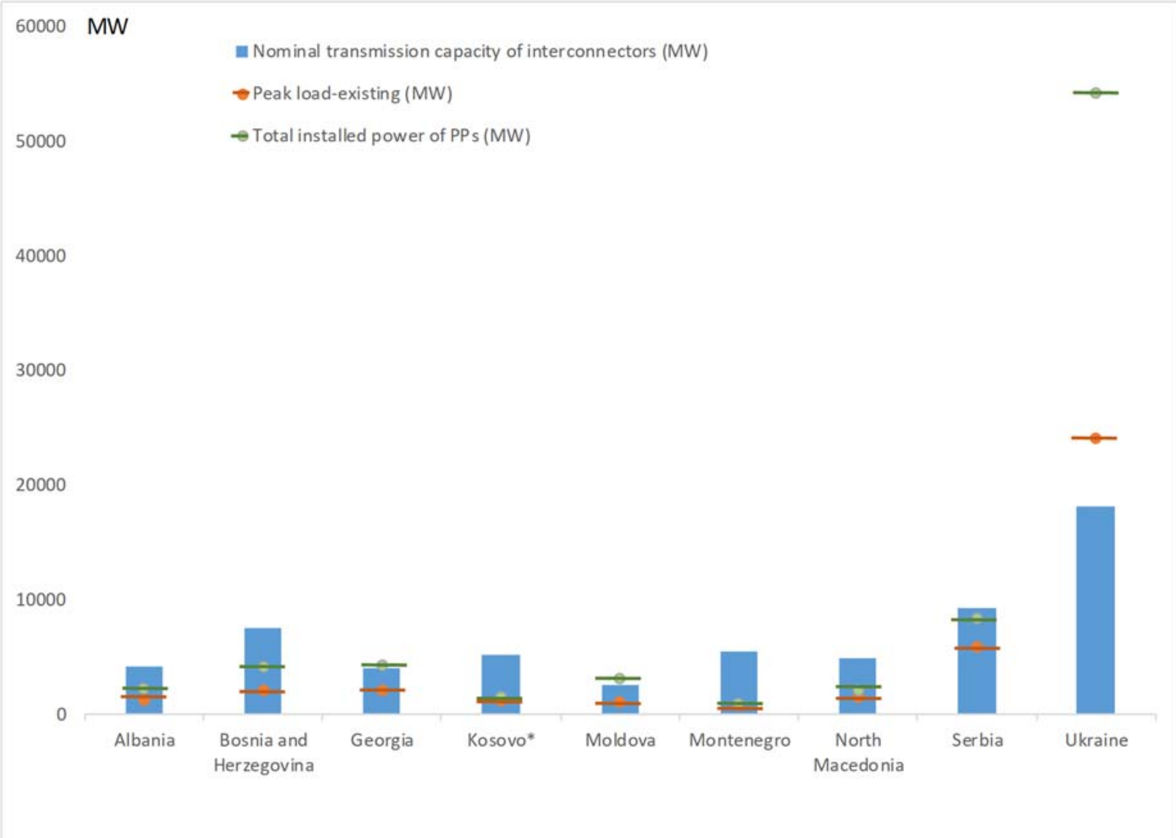


Figure 23: Nominal transmission capacity of the interconnectors, the existing level of peak load and the existing level of total installed power in all EnC CPs

Some Contracting Parties have plans to increase interconnection capacities even further and not on a small scale (total CAPEX of all planned projects is cca. 2.2 billion EUR). However, the realisation of these plans will strongly depend on future market conditions and economic viability of each candidate project. The existing estimation of investment costs for the new interconnection projects (excluding the North Macedonia – Albania line that is under construction) is as follows:

1) "Transbalkan Corridor" 1a) OHL 400 kV Bajina Basta (Serbia) – Visegrad (Bosnia and Herzegovina) 1b) OHL 400 kV Bajina Basta (Serbia) – Pljevlja (Montenegro) 1c) OHL 400 kV Kragujevac (Serbia) – Kraljevo (Serbia) 1c) OHL 2x400 kV Obrenovac (Serbia) – Bajina Basta (Serbia)	165 MEUR
2) OHL 330 kV Gardabani (Georgia) – Agstafa (Azerbaijan)	14 MEUR
3) HVDC 500/400 kV Akhaltsikhe (Georgia) – Tortum (Turkey)	95.53 MEUR
4) HVDC 400 kV Marneuli (Georgia) – Ayrum (Armenia)	11.2 MEUR
5) OHL 500 kV Ksani– Stepantsminda (Georgia) - Mozdok (Russia)	20.6 MEUR

6) HVDC 400 kV Anaklia (Georgia) – Constanta (Romania)	1139 MEUR
7) OHL 400 kV (B2B) Vulcanesti (Moldova) – Isaccea (Romania)	272 MEUR
8) OHL 400 kV Bălţi (Moldova) – Suceava (Romania) *Moldavian part only*	36.9 MEUR
9) OHL 400 kV Djerdap (Serbia) – Portile de Fiere (Romania) *revitalization of the existing line + internal line 400 kV and SS 400/110 kV in Serbia*	51.5 MEUR
10) OHL 400 kV Mukacheve (Ukraine) – Velke Kapusany (Slovakia)	23 MEUR
11) OHL 750/400 kV Uzhnoukrainska (Ukraine) – Isaccea (Romania)	231 MEUR
12) OHL 750 kV Khmelnytska NPP (Ukraine) – Rzeszov (Poland)	4 MEUR
13) OHL 400 kV Banja Luka (Bosnia and Herzegovina) – Lika	156 MEUR

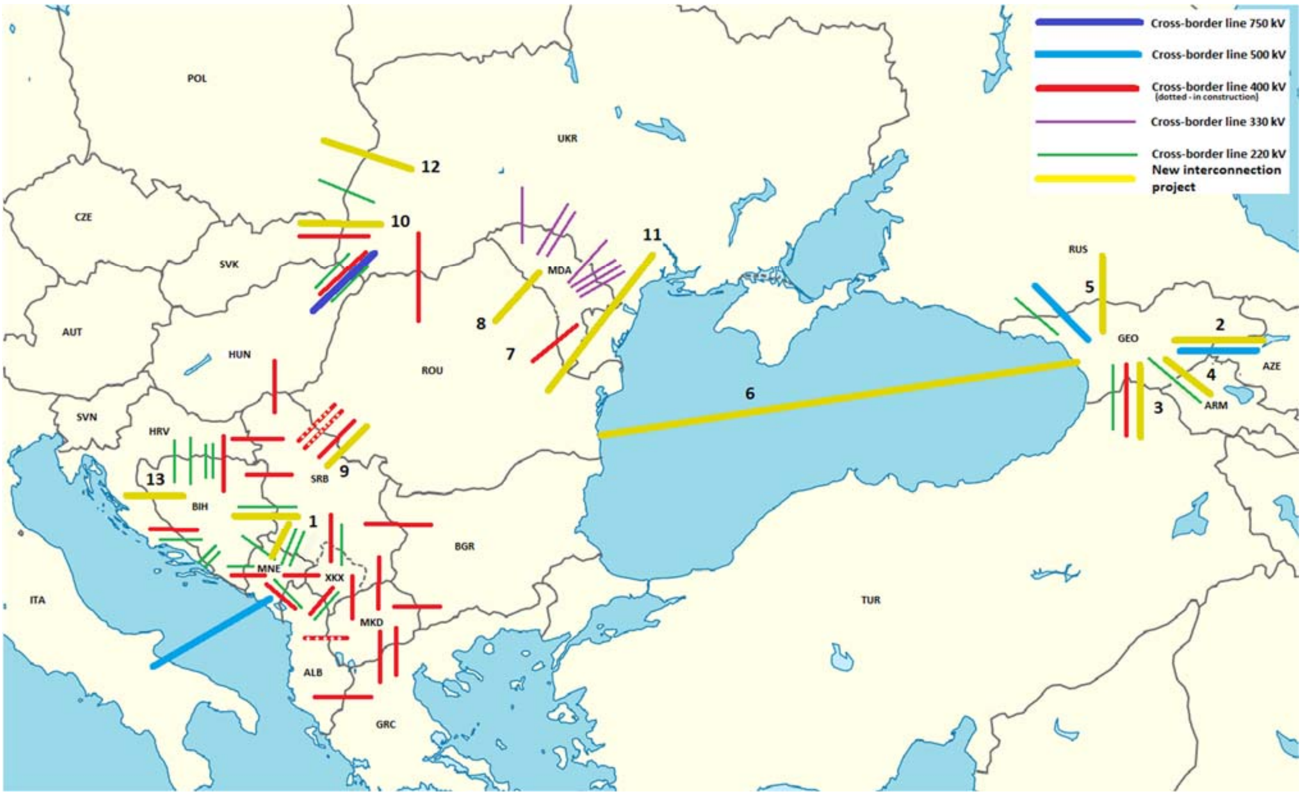


Figure 24: Existing and planned cross-border lines in the EnC Contracting Parties

4 Input data and assumptions

In order to estimate the existing and future compliance of the EnC Contracting Parties with the interconnectivity targets in 2020 and 2030 (expanded also to 2040), as defined and recommended by the European Commission, the basic data and assumptions are defined in this chapter based on the following:

- existing and future NTC values on all observed borders among the CPs and between CPs and EU Member States;
- nominal transmission capacities of interconnectors over all observed borders taking into account TSOs' development plans;
- future average wholesale electricity market prices in all CPs and neighbouring EU Member States;
- future peak load values for all CPs; and
- future integration of renewables in all CPs;

Previously listed data are highly uncertain because they depend on all kinds of different variables, like EU and national energy policies, strategies/plans, targets, investment costs of different electricity generation technologies etc. Therefore, different scenarios will be defined against which the interconnectivity targets will be evaluated.

4.1 The NTC values

Present and future maximum values of the NTCs over all observed borders, based on the description in the previous chapter, are shown in the following figures (Figure 25 - Figure 28). Red numbers represent the expected increase of the NTC values at relevant borders compared with the previous time frame (short-term time frame in comparison with the existing situation[15], mid-term time frame in comparison with the short-term time frame and long-term time frame in comparison with the mid-term time frame).

Increase of the maximum NTC values shown in the tables is related to the construction of new interconnection lines as planned by the TSOs. The increase does not reflect internal network reinforcements or any other kind of action which may cause the existing NTC values to increase. However, this approach does not mean that the increase of the NTC values is possible only due to the new interconnection lines. On the contrary, in some situations simpler and cheaper internal network reinforcements might lead to more efficient use of the interconnectors.

Tables which follow start with the existing indicative maximum NTC values which were described in the previous chapter and after that they show the possible increase of some NTC values in the short, mid and long-term time frame based on the construction plans of the new interconnectors.

In the short-term time frame, the NTC values might be increased at the Albania-Macedonia border (400 kV line Bitola – Elbasan under construction), the Serbia – Romania border (line 2x400 kV Pancevo – Resica planned to be finished on the Romanian side), the Georgia – Armenia/Azerbaijan/Turkey borders (according to Georgian TYNDP), the Moldova-Romania border (if planned B2B link is going to be commissioned) and the Ukraine-Slovakia border due to the planned revitalisation of the existing 400 kV line Mukacheve – V. Kapusany.

[15] Short-term refers to a time period of up to 3 years from now, mid-term cca. 5 years and long-term 10 years and more.

Additional NTC increases may happen in the mid-term time frame at the borders between Serbia and Romania due to planned internal network reinforcements in Romania, Serbia and BiH/Montenegro as the Transbalkan corridor is scheduled to be finished by then, the Moldova-Romania border (according to Moldelectrica's TYNDP) and the Georgia-Russia border (according to Georgian TYNDP).

In the long-term time frame, the NTC values might be increased at the borders between Bosnia and Herzegovina and Croatia, Georgia and Romania, Serbia and Romania, as well between Ukraine and Poland and Romania and Slovakia.

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Maximum import (MW)
ALB				400			441				400											1241
BIH							500	600				1000										2100
GEO																		150	630	570	700	2050
XKX	400				291		300	325														1316
MKD				150				300		250	350											1050
MDA									800							-						800
MNE	400	500		300				300						600								2100
SRB		600		325	250		200			350		600	700			800						3825
UKR						1200							900		0	400	600					3100
BGR					150			300														
GRC	400				300																	
HRV		1000						600														
HUN								800	800													
ITA							600															
POL									235													
ROU						-		800	400													
SVK									600													
ARM			150																			
AZE			630																			
RUS			570																			
TUR			700																			
Maximum export (MW)	1200	2100	2050	1175	991	1200	2041	4025	2835													

Figure 25: Maximum NTC values in the existing situation

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Maximum import (MW)
ALB				400	600		441				400											1841
BIH							500	600				1000										2100
GEO																		850	1260	570	1050	3730
XKX	400				291		300	325														1316
MKD	600			150				300		250	350											1650
MDA									800							600						1400
MNE	400	500		300				300						600								2100
SRB		600		325	250		200			350		600	700			1222						4247
UKR						1200							900		0	400	816					3316
BGR					150			300														
GRC	400				300																	
HRV		1000						600														
HUN								800	800													
ITA							600															
POL									235													
ROU						600		1100	400													
SVK									674													
ARM			850																			
AZE			1260																			
RUS			570																			
TUR			1050																			
Maximum export (MW)	1800	2100	3730	1175	1591	1800	2041	4325	2909													

Figure 26: Maximum NTC values in the short-term future situation

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Maximum import (MW)
ALB				400	600		441				400											1841
BIH							500	1310				1000										2810
GEO																		850	1260	1570	1400	5080
XKX	400				291		300	325														1316
MKD	600			150				300		250	350											1650
MDA									800							1000						1800
MNE	400	500		300				730						600								2530
SRB		1730		325	250		280			350		600	700			1644						5879
UKR						1200							900		0	400	816					3316
BGR					150			300														
GRC	400				300																	
HRV		1000						600														
HUN								800	800													
ITA							600															
POL									235													
ROU						1000		1400	400													
SVK									674													
ARM			850																			
AZE			1260																			
RUS			1570																			
TUR			1400																			
Maximum export (MW)	1800	3230	5080	1175	1591	2200	2121	5765	2909													

Figure 27: Maximum NTC values in the mid-term future situation

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Maximum import (MW)
ALB				400	600		441				400											1841
BIH							500	1310				1644										3454
GEO																1000		850	1260	1570	1400	6080
XKX	400				291		300	325														1316
MKD	600			150				300		250	350											1650
MDA									800							1100						1900
MNE	400	500		300				730						600								2530
SRB		1730		325	250		280			350		600	700			2266						6501
UKR						1200							900		600	1400	857					4957
BGR					150			300														
GRC	400				300																	
HRV		1298						600														
HUN								800	800													
ITA							600															
POL									835													
ROU			1000			1000		1747	1400													
SVK									700													
ARM			850																			
AZE			1260																			
RUS			1570																			
TUR			1400																			
Maximum export (MW)	1800	3528	6080	1175	1591	2200	2121	6112	4535													

Figure 28: Maximum NTC values in the long-term future situation

As a longer observed time frame brings more uncertainties which may significantly influence investment decisions, long-term projects should not be taken as granted, but rather as indicative investments which will be further studied.

It is obvious that today there are large gaps between nominal transmission capacities of the interconnectors and the NTC values given to the market participants, also due to the fact that the full utilization of the interconnectors is not possible as a result of highly meshed grids. In the WB6 area, each country has several thousand MWs of difference between the nominal transmission capacities of the interconnectors and the net transfer capacities given to the market participants. The same is valid for the border between Ukraine and Moldova, as well for borders between Burshtyn island and surrounding EU countries.

4.2 Nominal transmission capacities of the interconnectors

Nominal transmission capacities of the interconnectors in the existing and short, mid and long-term future are summarized in the following figures. At the moment, all CP TSOs are planning to increase cross-border capacities except Kosovo*. Interconnection capacities are scheduled to be increased significantly in Georgia (109 % increase compared with the existing situation), Moldova (74 % increase), Serbia (64 % increase) and Ukraine (55 % increase observing interconnections with ENTSO-E only). A moderate increase is expected in all other countries excluding Kosovo* (from 22 % to 32 % increase).

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Nominal transmission capacity of interconnectors (MW)
ALB				1455			1467				1215											4137
BIH							1795	1466				4186										7448
GEO*																		240	1740	1530	700	3970
XKX	1455				1096		1185	1455														5192
MKD				1096				1096		1096	1548											4837
MDA									2602							-						2602
MNE	1467	1795		1185				493						600								5541
SRB		1466		1455	1096		493			1196		1196	1196			1146						9245
UKR**						2602							3277		297	1151	979			7929		8306
BGR					1096			1196														
GRC	1215				1548																	
HRV		4186						1196														
HUN								1196	3277													
ITA							600															
POL									297													
ROU						-		1146	1151													
SVK									979													
ARM			240																			
AZE			1740																			
RUS			1530						7929													
TUR			700																			

* nominal transmission capacity of the interconnectors in Georgia 2110 MW according to GSE data (lines to Russia, Azerbaijan and Turkey included)
** toward ENTSO-E+Moldova only

Figure 29: Nominal transmission capacities of interconnectors in the existing situation

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Nominal transmission capacity of interconnectors (MW)
ALB				1455	1195		1467				1215											5332
BIH							1795	1466				4186										7448
GEO*																		940	2450	1530	1050	5030
XKX	1455				1096		1185	1455														5192
MKD	1195			1096				1096		1096	1548											6032
MDA									2602							600						3202
MNE	1467	1795		1185				493						600								5541
SRB		1466		1455	1096		493			1196		1196	1196			3540						11639
UKR						2602							3277		297	1151	979			7929		8306
BGR					1096			1196														
GRC	1215				1548																	
HRV		4186						1196														
HUN								1196	3277													
ITA							600															
POL									297													
ROU						600		3540	1151													
SVK									979													
ARM			940																			
AZE			2450																			
RUS			1530						7929													
TUR			1050																			

* the nominal transmission capacity of the interconnectors in Georgia amounts to 3170 MW according to GSE data (lines to Russia, Azerbaijan and Turkey included)

Figure 30: Nominal transmission capacities of interconnectors in the short-term future time frame

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Nominal transmission capacity of interconnectors (MW)
ALB				1455	1195		1467				1215											5332
BIH							1795	2662				4186										8644
GEO*																		940	2450	3060	1400	6910
XKX	1455				1096		1185	1455														5192
MKD	1195			1096				1096		1096	1548											6032
MDA									2602							1919						4521
MNE	1467	1795		1185				1690						600								6738
SRB		2662		1455	1096		1689			1196		1196	1196			3540						14031
UKR						2602							3277		297	1151	979			7929		8306
BGR					1096			1196														
GRC	1215				1548																	
HRV		4186						1196														
HUN								1196	3277													
ITA							600															
POL									297													
ROU						1919		3540	1151													
SVK									979													
ARM			940																			
AZE			2450																			
RUS			3060						7929													
TUR			1400																			

* The nominal transmission capacity of the interconnectors in Georgia amounts to 4520 MW according to GSE data (lines to Russia, Azerbaijan and Turkey included)

Figure 31: Nominal transmission capacities of interconnectors in the mid-term future time frame

To \ From	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK	ARM	AZE	RUS	TUR	Nominal transmission capacity of interconnectors (MW)
ALB				1455	1195		1467				1215											5332
BIH							1795	2662				5382										9840
GEO*																1000		940	2450	3060	1400	7910
XKX	1455				1096		1185	1455														5192
MKD	1195			1096				1096		1096	1548											6032
MDA									2602							1919						4521
MNE	1467	1795		1185				1690						600								6738
SRB		2662		1455	1096		1689			1196		1196	1196			4685						15177
UKR						2602							3277		2052	2951	1969			7929		12851
BGR					1096			1196														
GRC	1215				1548																	
HRV		5382						1196														
HUN								1196	3277													
ITA							600															
POL									2052													
ROU			1000			1919		4685	2951													
SVK									1969													
ARM			940																			
AZE			2450																			
RUS			3060						7929													
TUR			1400																			

* The nominal transmission capacity of the interconnectors in Georgia amount to 5520 MW according to GSE data (lines to Russia, Azerbaijan and Turkey included)

Figure 32: Nominal transmission capacities of interconnectors in the long-term future time frame

The country with the largest nominal transmission capacity of the interconnectors will be Serbia, with more than 15 GW (today 9.2 GW). Ukraine follows (observing lines to the ENTSO-E system and Moldova only) with 12.9 GW in the long-term time frame (today 8.3 GW). All other countries are going to have nominal transmission capacities of the interconnectors larger than 5 GW per country, with the smallest long-term value of 4.5 GW in Moldova.

The sum of nominal transmission capacities of the interconnectors of all CPs today is around 51 GW (excluding Ukrainian lines toward Russia and Belarus). This value will be increased up to 74 GW (~2030) if all TSOs realize their development plans, that is an increase of 44 % compared with the existing situation.

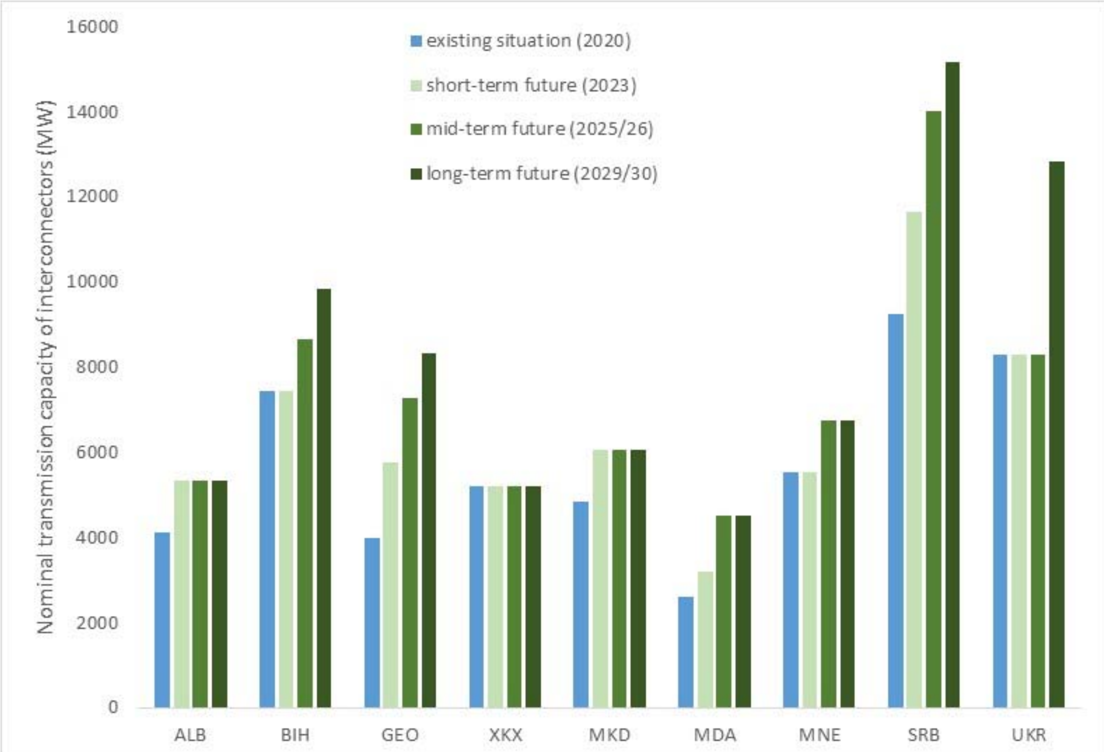


Figure 33: Nominal transmission capacities of interconnectors as planned by the TSOs

4.3 Wholesale electricity market prices

The indicator is the day-ahead price formed through an auction process. At the open electricity market/auction, producers give bids related to how much energy they are willing to sell and produce during a specific time period and what is the price of this energy offered to consumers and traders/resellers/suppliers. The bid of the cheapest producer will clear the market first, followed by the next cheapest producer, until offered electricity matches all needs (consumers and suppliers also give their bids about the energy and the price at which they are willing to buy). The price of the last producer to offer electricity will define the wholesale price of electricity for a specific time frame.

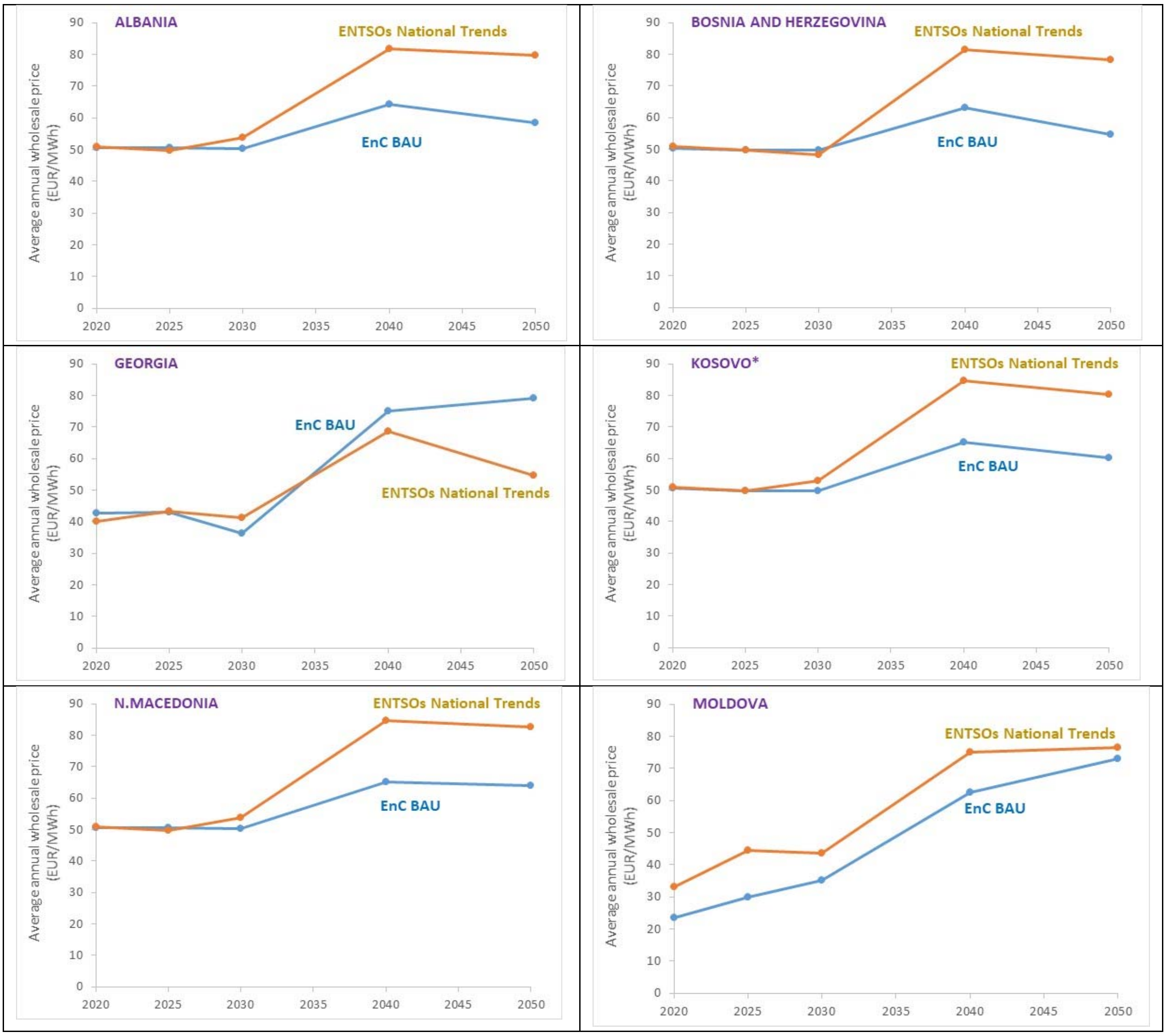
Market simulators are software tools used to calculate and predict the wholesale electricity market prices in a certain area in the future. If there are no transmission congestions between the different zones, the market price would be equal over the observed area and the wholesale electricity price would be the lowest. In contrast, if there are some transmission congestions, more expensive generators will have to be engaged in some zones and the wholesale market prices will vary in the zones with congested transmission lines.

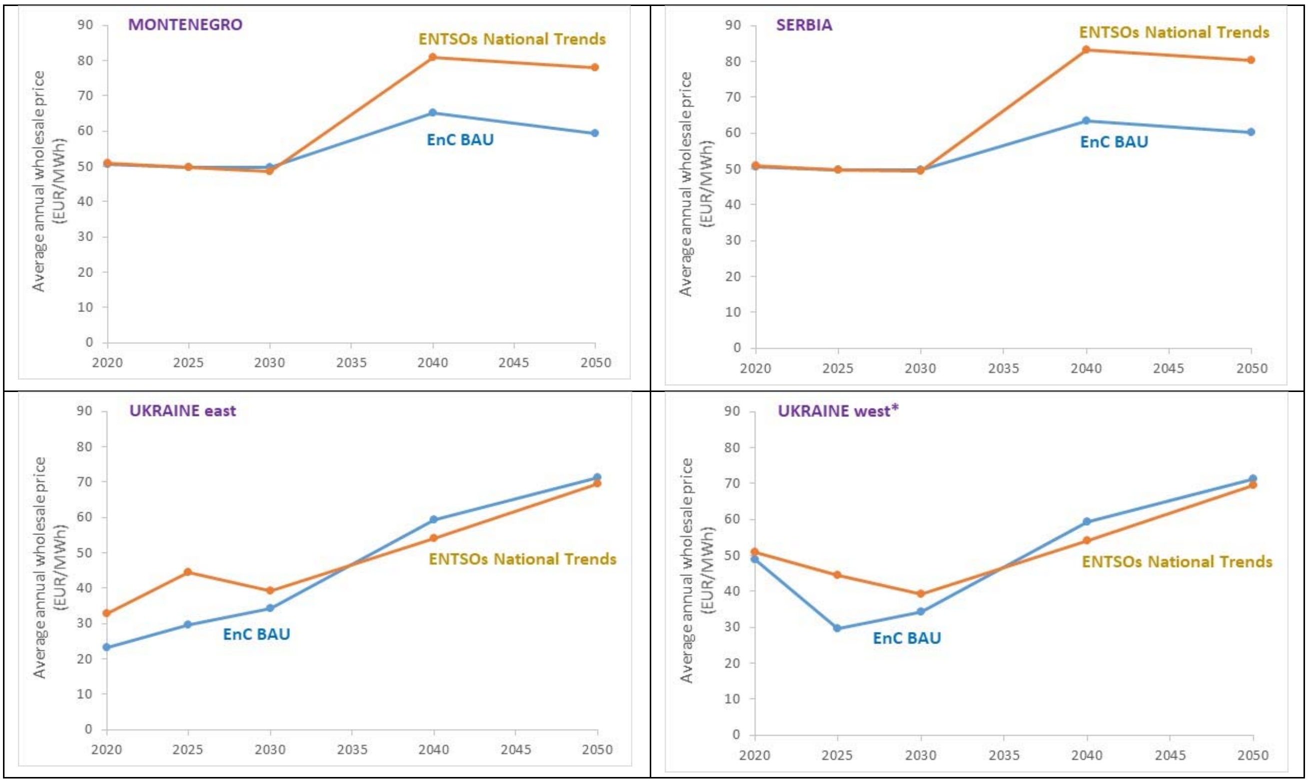
A difference in the wholesale electricity market prices between bidding zones is an excellent indicator of the economic viability of possible transmission reinforcements, assuming that the existing ones are used efficiently, because it shows how much electricity would normally flow between two or more zones if transmission lines were not congested and generators were ideally engaged based on their increasing bids.

Results of such market simulations and calculated wholesale electricity market prices are highly uncertain due to many different factors influencing these prices in the future. Different studies with different assumptions and scenarios will give different predictions of the wholesale electricity market prices (often observed as an average wholesale price over one year). Fuel costs, CO_2 emission costs, electricity consumption, NTC values, the level of renewables integration and time-series of their production, etc. are all going to influence significantly the calculation results bringing different future wholesale prices in an observed area.

Prediction of the wholesale electricity market prices in the EnC Contracting Parties presented in this chapter is based on the calculation results of the market simulations performed during the PECI/PMI selection process in 2020 [3].

Market simulations for the PECI/PMI 2020 process were based on country specific data submitted by CPs TSOs and/or the Ministries (the scenario defined according to these data is named EnC BAU), and data listed in the ENTSO-E and ENTSO-G National Trends (NT) scenario defined during the TYNDP 2020 preparation process.





* Wholesale electricity price for Ukraine-east and Ukraine-west was assumed to be equal after synchronisation with ENTSO-E from 2025 onwards

Figure 34: Average annual wholesale electricity prices in the EnC CPs according to the PECI/PMI 2020 market simulations (€/MWh) [3]

The previous figure shows results of the market simulations without any new cross-border transmission project being included (except Bitola – Elbasan line that is under construction) with the NTC values defined according to the existing situation. It is forecasted that wholesale prices are going to rise due to increasing CO_2 emission costs and later in 2050 slightly fall down due to the high share renewables in the generation mix.

Average annual wholesale electricity prices, according to the market simulations performed during the PECI/PMI 2020 selection process, are forecasted to be at the level of approximately 50 EUR/MWh in 2030 (including CO_2 emission costs) for both analysed scenarios, except in Georgia, Moldova and Ukraine where the average wholesale prices are around 10 to 15 EUR/MWh lower. In 2040, an increase of the average wholesale prices is expected up to cca. 65 EUR/MWh for the EnC BAU scenario and above 80 EUR/MWh for the ENTSOs NT scenario (CO_2 costs included). In 2050, the average wholesale electricity prices should fall to a level of 60 EUR/MWh for the EnC BAU scenario and 80 EUR/MWh for the ENTSOs NT scenario.

The market simulation results listed above were compared with the results of the ENTSO-E study on power system needs in 2030 and 2040 (https://tyndp.entsoe.eu/system-needs/), prepared within the TYNDP 2020 process [19]. Scenarios without any investments after 2020 and 2025 were observed in order to make both sets of results more comparable. The average marginal electricity costs for 2030 in the study and the PECI/PMI 2020 process are closely aligned, with a cca. 5 EUR/MWh difference applicable to all countries which were taken into consideration. Results for 2040 deviate significantly, obviously due to large differences in the input data and assumptions.

Country	Time frame	2020		2025		2030		2040		2050	
	Scenario	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends	EnC BAU	ENTSOs National Trends
ALB	EnC Contracting Parties	50.58	50.99	50.62	49.87	50.18	53.75	64.16	81.72	58.44	79.64
BIH		50.18	50.99	49.72	49.60	49.73	48.23	63.10	81.48	54.83	78.34
GEO		42.84	40.18	43.00	43.31	36.41	41.40	75.19	68.56	79.22	54.60
XKX		50.58	50.99	49.78	49.87	49.76	53.01	65.29	84.68	60.23	80.43
MKD		50.58	50.99	50.62	49.87	50.18	53.82	65.29	84.54	63.89	82.71
MDA		23.53	33.07	29.95	44.59	35.16	43.59	62.54	75.14	73.05	76.42
MNE		50.58	50.99	49.77	49.81	49.76	48.45	65.09	80.89	59.28	77.86
SRB		50.58	50.99	49.73	49.87	49.73	49.47	63.48	83.31	60.31	80.31
UKR east		23.37	32.94	29.65	44.42	34.43	39.38	59.31	54.01	71.35	69.42
UKR west		48.87	50.99	29.65	44.42	34.43	39.38	59.31	54.01	71.35	69.42
BGR	EU Member States	50.54	50.95	51.97	52.91	49.50	54.50	65.25	83.63	63.72	79.00
GRC		58.97	51.70	51.98	52.91	48.64	54.10	61.92	84.23	58.91	81.59
HRV		50.09	50.99	49.72	49.60	49.73	47.41	63.01	81.36	59.63	78.20
HUN		50.09	50.99	49.72	49.60	49.73	47.58	63.02	83.00	59.83	80.16
ITA		51.63	51.07	51.68	53.49	48.21	45.49	66.68	51.50	61.20	50.56
POL		46.85	56.34	49.24	54.67	51.69	47.91	58.18	62.79	57.17	64.03
ROU		50.96	50.99	49.75	50.03	49.73	49.30	63.19	83.05	59.35	80.13
SVK		44.63	49.26	49.73	49.87	48.66	47.81	57.73	87.48	61.01	85.59

Figure 35: Average annual wholesale electricity prices without new interconnection projects included according to PECI/PMI 2020 selection process (€/MWh) [3]

Country	Time frame	2030	2040	Difference (PECI-IoSN)	
	Scenario	EnC BAU	EnC BAU	2030	2040
ALB	EnC Contracting Parties	44.99	66.66	5.19	-2.50
BIH		44.11	65.89	5.62	-2.79
GEO		-	-	-	
XKX		-	-	-	
MKD		45.34	74.76	4.84	-9.47
MDA		-	-	-	
MNE		44.12	67.24	5.64	-2.15
SRB		44.12	71.09	5.61	-7.61
UKR east		-	-	-	
UKR west		-	-	-	
BGR	EU Member States	45.44	82.01	4.06	-16.76
GRC		54.63	75.27	-5.99	-13.35
HRV		44.55	73.91	5.18	-10.90
HUN		44.55	80.11	5.18	-17.09
ITA		47.83	62.51	0.38	4.17
POL		49.19	71.49	2.50	-13.31
ROU		42.89	41.19	6.84	22.00
SVK		44.34	80.61	4.32	-22.88

Figure 36: Average marginal electricity cost in EUR/MWh from the “Power system needs in 2030 and 2040” study and difference between these results and PECI/PMI 2020 market simulation results

4.4 Peak load values

Forecasts of the peak load values in the CPs were collected from different sources. The ENTSO-E TYNDP 2020 was used to obtain data for the WB6 countries while different documents (national TYNDPs, system adequacy reports, etc.) were used for Ukraine, Georgia and Moldova. It is clear that these forecasts also encompass a high level of uncertainty since there are many influential factors which will determine the load growth pattern in the future. That is why different scenarios of the peak load growth are shown here. Three ENTSO-E TYNDP 2020 scenarios were used for the WB6, excluding Kosovo*. The Kosovar peak demand values were extracted from KOSTT's TYNDP, while the Serbian peak load values in the ENTSO-E TYNDP 2020 were reduced for the Kosovar peak demand. Peak load forecast for Ukraine was made according to several scenarios (baseline, maximum energy efficiency, reference scenario and climate-neutral economy scenario) bringing a very large span of possibilities especially in 2040. Maximum peak load values, which are checked later against the interconnectivity targets, are as follows.

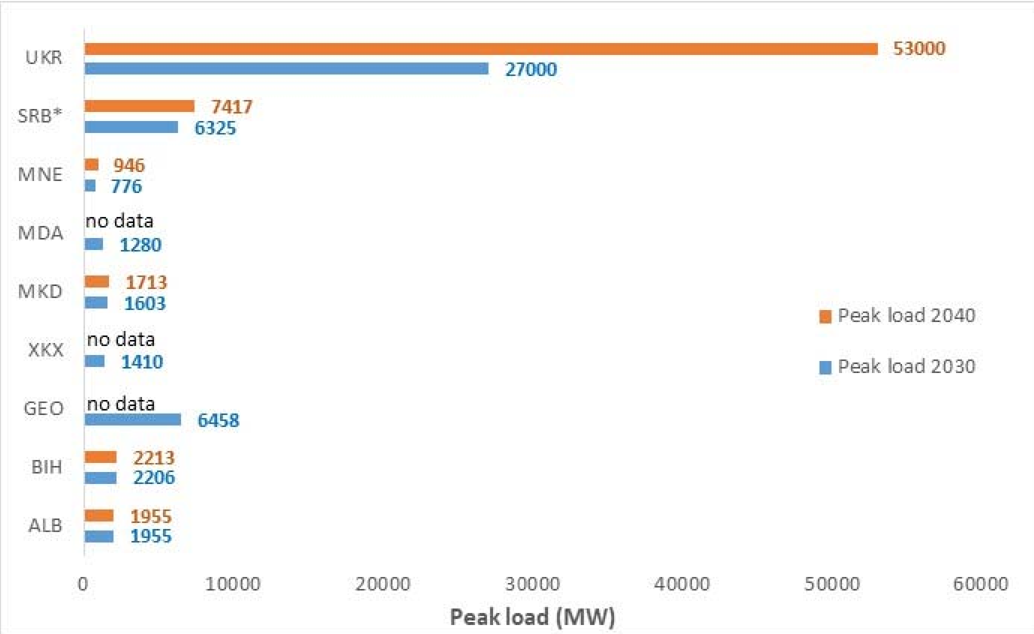


Table 21: Peak load forecasts (MW)

Country	2030			2040		
	National Trends	Global Ambition	Distributed Energy	National Trends	Global Ambition	Distributed Energy
ALB	1955	1955	1955	1955	1955	1955
BIH	2130	2206	2138	2148	2213	2184
GEO	2934 - 6458			-		
XKX	1174 - 1410			-		
MKD	1603	1311	1518	1713	1382	1529

Country	2030			2040		
	National Trends	Global Ambition	Distributed Energy	National Trends	Global Ambition	Distributed Energy
MDA	1085			-		
MNE	776	479	532	946	495	525
SRB*	7735	4582	5445	8827	4729	5526
UKR	20000 - 27000			28000 - 53000		

* including Kosovo*

Source: TYNDP 2020 Scenarios, TYNDP of Georgia and Kosovo, system adequacy assessment 2020 for Ukraine*

4.5 Existing installed generation capacities

Installed generation capacities are the input value needed to check the fulfilment of the interconnectivity target in 2020, because the total NTC value is compared with the total generation capacity in one country. According to the ENTSO-E statistical factsheet 2018 [21] and other sources (TYNDPs and adequacy reports), the total net generation capacities in the Contracting Parties are as shown in the following table.

The total installed net generation capacity in the CPs is around 80 GW, of which 68 % is in Ukraine, 10 % in Serbia and 5 % in Bosnia and Herzegovina and Georgia each, while other countries participate with shares lower than 4 % of the total generation capacity. The generation mix in the EnC CPs consists of thermal power plants (coal, gas and oil) with installed capacity of 40.5 GW (51 % of total generation capacity), hydro facilities (18 GW, 23 %), nuclear power plants in Ukraine only (13.8 GW, 18 %), while renewable energy sources have installed capacity of 6.9 GW at the moment, which is slightly below 9 % of the total generation capacity.

Table 22: Total net generation capacities in the EnC CPs today (MW)

Country	Coal , oil and other fossil fuels	Gas	Nuclear	Hydro	Wind	Solar	Other RES	TOTAL (MW)
ALB	97	0	0	1835	0	0	0	**1932**
BIH	1888	0	0	2105	87	0	0	**4080**
GEO	925		0	3300	21	0	0	**4246**
XKX	1147	0	0	92	1	7	0	**1247**
MKD	907	250	0	676	37	17	7	**1894**
MDA	2937		0	64	0	0	7	**3008**
MNE	220	0	0	660	118	0	0	**998**
SRB	4026	208	0	3038	373	10	0	**7655**
UKR	27900		13835	6300	1100	4900	186	**54221**

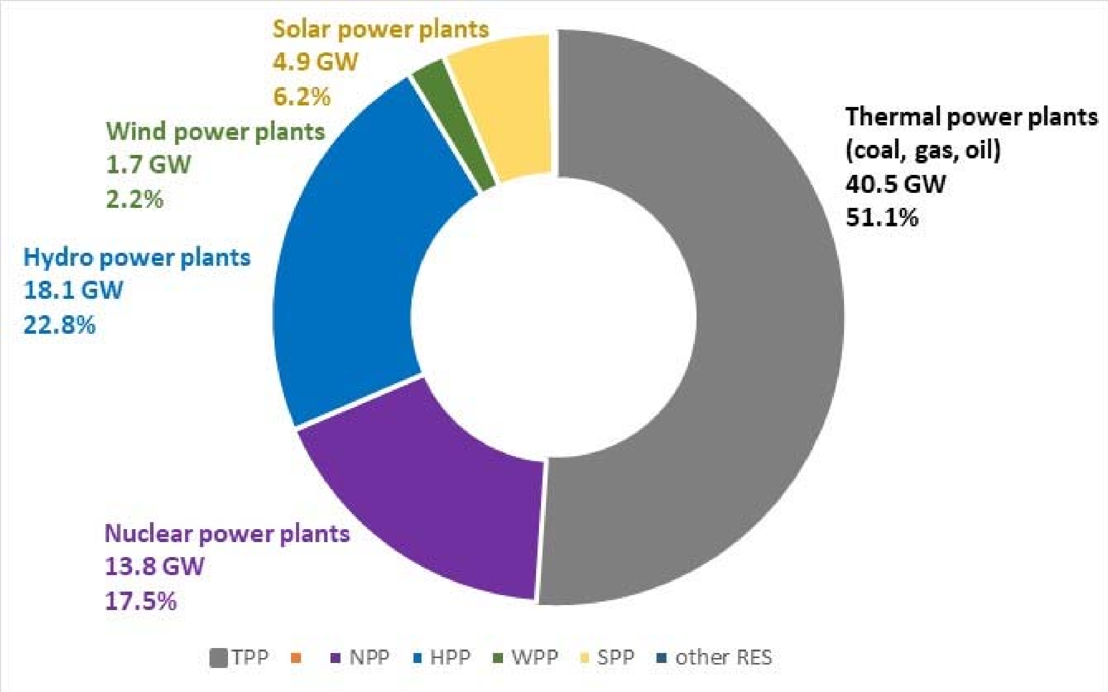


Figure 37: Share of different technologies in the generation mix of the EnC CPs today

4.6 Integration of renewable energy sources

Assumptions on the future integration of renewables (hydro, wind, solar and other RES) in the Contracting Parties[16] were taken from two sources. The PECI/PMI selection process in 2020 [3] is used as the first source and a recent study by IRENA and the European Commission is used as the second source for RES integration predictions in 2030 [22] since it provides higher RES integration numbers. RES integration values in the CPs based on the various scenarios are presented in the following table.

For the purpose of analysing the CPs' compliance with the interconnectivity targets, maximum reference values were used with respect to the future long-term time frame in 2030 and 2040. These values are coloured in the table below. As the IRENA study is limited to the 2030-time frame, only PECI/PMI data were used for 2040 values unless the IRENA study data for 2030 is higher.

The next figure shows the existing level of RES in the CPs and maximum predictions for 2030 and 2040. Forecasts of the RES integration increase are significant for all observed countries, within the range of 110 % compared with the existing situation in Montenegro (778 MW today and 1635 MW in 2030) to 2152 % in Moldova (71 MW today and 1599 MW in 2030). This means that existing RES capacities are going to be at least doubled or even increased by more than tenfold compared to the present situation, which makes the analysis presented in the next chapter rather conservative.

[16] Until December 2020, no Contracting Party has adopted a National Energy and Climate Plan (NECP), which would serve as a source of data about RES integration.

Table 23: RES integration scenarios in the EnC CPs (total installed capacity of RES in MW)

Country	2030		2040		IRENA study*	MAX 2030	MAX 2040
	EnC BAU	National Trends	EnC BAU	National Trends			
ALB	3502	3850	5729	6554	3926	3926	6554
BIH	3205	3000	7007	5062	5213	5213	7007
GEO	8386	4391	8386	5967	-	8386	8386
XKX	737	617	1662	617	1639	1639	1662
MKD	1624	1768	2296	2741	2791	2791	2791
MDA	495	580	855	968	1599	1599	1599
MNE	1474	1635	2514	2969	1385	1635	2969
SRB	6349	7052	7885	7852	9222	9222	9222
UKR	20450	15853	22450	21463	34021	34021	34021

**Renewable energy prospects for Central and South-eastern Europe energy connectivity*, IRENA, 2020

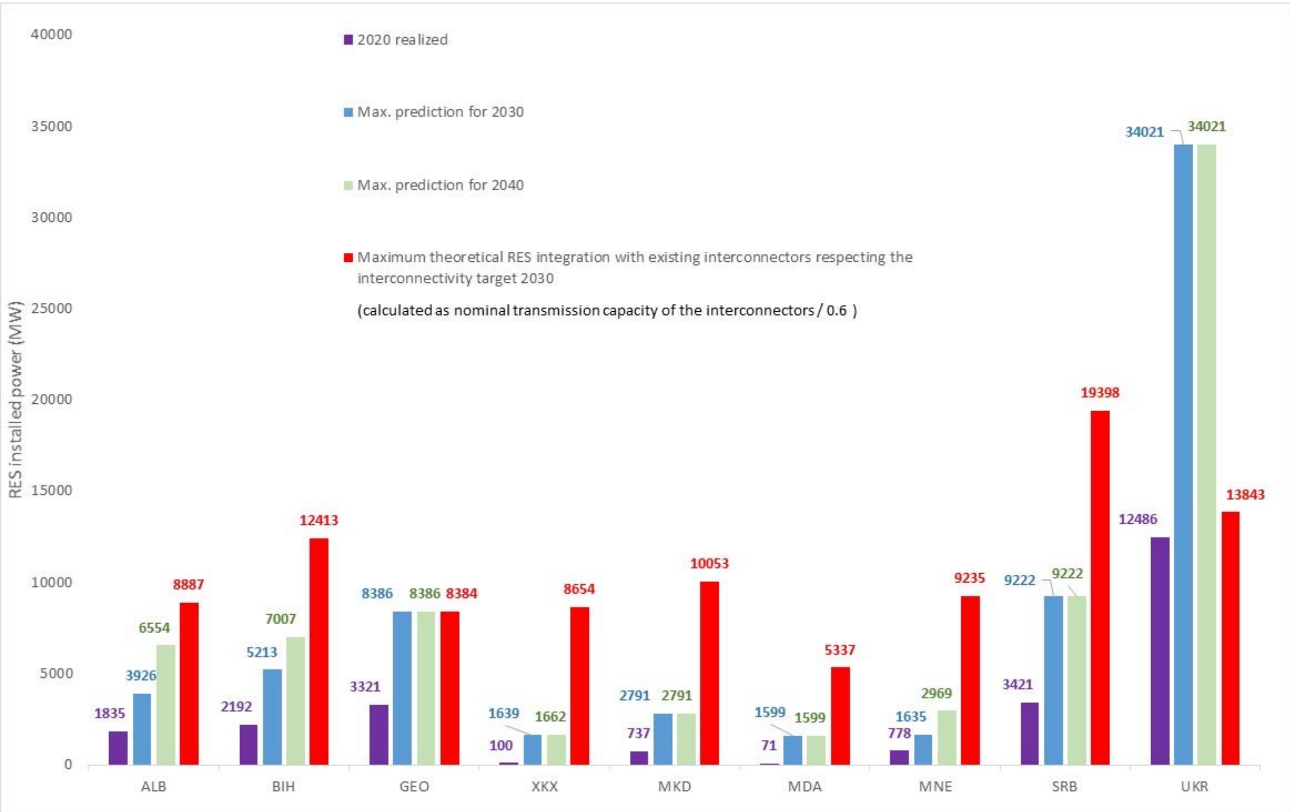


Figure 38: Level of RES integration today and maximum predictions for 2030 and 2040

Just for illustration purposes, the figure also shows maximal theoretical RES integration from the infrastructural point of view but neglecting other possible limitations (RES potential, economic viability, balancing considerations, system inertia, costs, etc.), taking into account the 2030 interconnectivity target. The second threshold in this target (60 %) was used to calculate the maximal theoretical RES integration as the ratio between nominal transmission capacity of existing interconnectors and the factor 0.6 (expressed as 4: $MAX\ P_{RES\_generation} < \Sigma P_n / 0.6$).

The previous figure clearly shows that the existing cross-border infrastructure will not restrict RES integration and hinder the CPs from meeting this 2030 interconnectivity target even when maximum predictions are taken into account. The only exception may be Ukraine (the red column is larger than the blue and green ones for all countries except Ukraine). Predictions for Georgia using GSE data suggest that the existing interconnectors only just meet the RES integration needs or are slightly below.

5 Compliance with the interconnectivity targets applied in the EU

This chapter examines the Contracting Parties' compliance with the EU interconnectivity targets under the current conditions and in the long-term future time frame. Their compliance related to the existing situation is analysed with respect to the 10 % criterion, while their compliance with the interconnectivity targets in 2030 and 2040 is analysed with respect to the EU set criterions for the expected wholesale electricity price difference, the ratio between nominal transmission capacity of the interconnectors and peak load and the ratio between nominal transmission capacity of the interconnectors and installed power of renewables.

The most unfavourable data are used while evaluating compliance against the interconnectivity targets in order to take into account future uncertainties, which are deemed to be significant. A sensitivity analysis was also performed to estimate their impact. This means that the nominal transmission capacity of the existing interconnectors is used, as possible future network reinforcements would only have a positive impact. The only exception is the new 400 kV line Bitola – Elbasan between Albania and North Macedonia, which is currently under construction. Planned projects of other countries were initially neglected but taken into account later during the evaluation of individual criteria and the sensitivity analysis. The most unfavourable data or the maximum predicted values were used for peak load and installed renewables capacities in order to reach the smallest ratios between nominal transmission capacity of the interconnectors and the denominator values.

As mentioned above the targets applied in the EU are not binding on the Contracting Parties, however, the assessment in this report uses the EU targets as a benchmark.

5.1 10 % criterion in 2020

Compliance of the EnC CPs with the 2020 interconnectivity target is shown in the following table. Numbers within the table are calculated as the ratio between the sum of the maximum NTC values on the borders and the total installed capacity of generators in each country. Numbers for Ukraine are given by respecting four possible situations:

- all cross-border lines are observed, including the ones toward UPS/IPS and ENTSO-E, at the same time and the total generation fleet in Ukraine is included;
- cross-border lines toward ENTSO-E are included together with the total generation fleet in Ukraine (expected situation in the short to mid-term future);
- cross-border lines toward ENTSO-E, which are currently under normal operation, are included together with the generation fleet within Burshtyn island; and
- cross-border lines toward UPS/IPS are included together with the total generation fleet in Ukraine (existing situation).

Acknowledging the fact that maximal NTC values are rather restricted when compared to the nominal transmission capacity of the interconnectors, they are still sufficient to meet the desired 2020 interconnectivity target in all Contracting Parties. The WB6 countries are more interconnected than Western European countries, having observed much higher rations in the range of 50 % (Serbia) to 210 % (Montenegro). This clearly shows that full market integration in the WB6 area has not been prevented by the lack of interconnectors, but rather their inefficient use as may be seen in Figure 21. With respect to the Eastern CPs, Moldova and Ukraine are mutually very strongly interconnected but import to Moldova from Ukraine is heavily restricted. The ratio between existing NTC values on Ukrainian borders to the EU MS and total generation capacity in Ukraine is only 6 %, indicating that synchronisation of Ukraine and Moldova with the continental European power system will lead to more efficient usage of the existing interconnectors and probably the construction of new ones. In the meantime, the Burshtyn island connection to the European system satisfies the existing interconnectivity target despite the rather restricted exchange possibilities between this part of Ukraine and Slovakia/Hungary/Romania.

Table 24: EnC CPs compliance with the 2020 interconnectivity target

Country	2020 interconnectivity target
ALB	64%
BIH	51%
GEO	48%
XKX	106%
MKD	55%
MDA	27%
MNE	210%
SRB	50%
UKR	11%
UKR (1) ENTSO-E connected	*6%*
UKR (2) Burshtyn island	*25%*
UKR (3) UPS/IPS connected	*6%*

UKR: the whole of Ukraine is observed, all cross-border lines included
UKR (1): the whole of Ukraine is observed, only cross-border lines to ENTSO-E included
UKR (2): only Burstyn island is observed, NTC of 650 MW toward Slovakia, Hungary and Romania
UKR (3): the whole of Ukraine minus Burshtyn island is observed, only cross-border lines to the IPS/UPS included

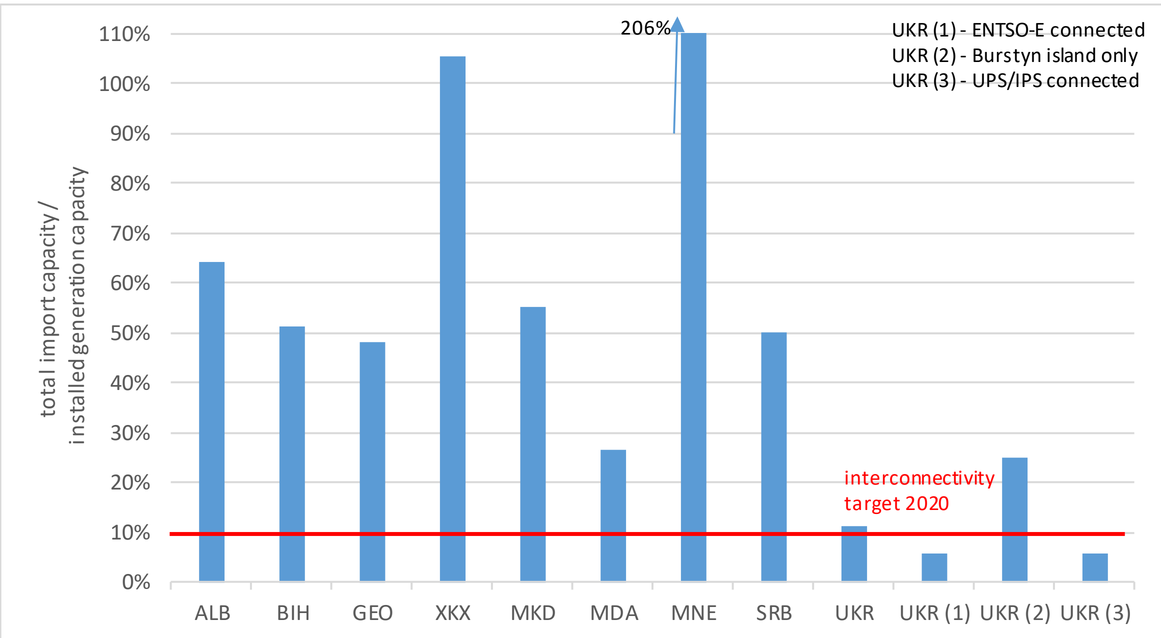


Figure 39: 2020 interconnection target compliance

5.2 15 % criterion in 2030

5.2.1 Wholesale electricity price difference

The EU has chosen to use the difference between countries' wholesale market prices as an indicator of sufficient interconnector capacity, applying a threshold of 2 €/MWh. If there is a difference larger than the threshold, additional capacity might be necessary. If not, there is probably no need to increase transmission capacity or the NTC at the observed border. The larger the price difference is, the higher the need to increase capacity. A cost benefit analysis is likely to support this increase[17].

The wholesale price differences for the two analysed scenarios (Business as Usual and ENTSO-E National Trends) in 2030 and 2040, without additional interconnectors compared to the existing situation, are shown in the following figures. The price differences shown in the columns are calculated as Country 2 price minus Country 1 price, meaning that a positive value in a column means that the price in Country 2 is higher than in Country 1 (a negative value means that the price in Country 1 is higher). Red numbers mean that the price differential is larger than the threshold of 2 €/MWh.

In the Business as Usual 2030 scenario, the price differences for the majority of borders are below the threshold except at the border between Moldova and Romania as well as Ukraine and surrounding ENTSO-E countries. The significant price differences of 15-17 €/MWh are caused by the lack of interconnection capacities between Ukraine/Moldova and Poland/Slovakia/Hungary/Romania. It was assumed that Ukraine and Moldova will operate synchronously with the European countries in the 2030 time frame and it is quite obvious that the existing NTC values cannot fully support the expected market activities.

Country 1 \ Country 2	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK
ALB				-0.42			-0.42				-1.54						
BIH							0.03	0.00				0.00					
GEO																	
XKX	0.42				0.42		0.00	-0.03									
MKD				-0.42				-0.45		-0.68	-1.54						
MDA									-0.73							14.57	
MNE	0.42	-0.03		0.00				-0.03						-1.55			
SRB		0.00		0.03	0.45		0.03			-0.23		0.00	0.00			0.00	
UKR						0.73							15.30		17.26	15.30	14.23
BGR					0.68			0.23									
GRC	1.54				1.54												
HRV		0.00						0.00									
HUN								0.00	-15.30								
ITA							1.55										
POL									-17.26								
ROU						-14.57		0.00	-15.30								
SVK									-14.23								

Figure 40: Differences in average annual wholesale electricity prices without new interconnection projects included: Business as Usual scenario in 2030 (€/MWh) [based on ref.3]

[17] Increase of the Net Transfer Capacity may be achieved by different means, with the construction of a new interconnection line being probably the most complicated and the most expensive action.

Country 1 / Country 2	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK
ALB				-0.74			-5.30				0.35						
BIH							0.22	1.24				-0.82					
GEO																	
XKX	0.74				0.81		-4.56	-3.54									
MKD				-0.81				-4.35		0.68	0.28						
MDA									-4.21							0.00	
MNE	5.30	-0.22		4.56				1.02						-2.96			
SRB		-1.24		3.54	4.35		-1.02			5.03		-2.06	-1.89			-0.17	
UKR						4.21							8.2		8.53	9.92	8.43
BGR					-0.68			-5.03									
GRC	-0.35				-0.28												
HRV		0.82						2.06									
HUN								1.89	-8.20								
ITA							2.96										
POL									-8.53								
ROU						0.00		0.17	-9.92								
SVK									-8.43								

Figure 41: Differences in average annual wholesale electricity prices without new interconnection projects included: ENTSO-E National Trends scenario in 2030 (€/MWh) [based on ref.3]

In the National Trends scenario, many more borders are congested (12 in total), with the largest price difference of 9.9 €/MWh (Ukraine/Romania border, Figure 41). The assumed NTC at this border is 400 MW, while total transmission capacity of all interconnectors is 1151 MW, meaning that the first action should be to increase the NTC by using existing infrastructure (if necessary reinforce it internally) in order to reduce the price difference between the two countries.

In the Business as Usual scenario in 2040, two borders in the WB6 area may experience occasional congestions (Albania/Greece and N. Macedonia/Greece). A price difference large than the threshold is also visible at the Ukrainian borders to Hungary and Romania, with the largest price difference at the Ukrainian/Romanian border.

Country 1 / Country 2	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK
ALB				1.13	1.13		0.93				-2.24						
BIH							1.99	0.38				-0.09					
GEO																	
XKX	-1.13				0.00		-0.20	-1.81									
MKD	-1.13			0.00				-1.81		-0.04	-3.37						
MDA									-3.23							0.65	
MNE	-0.93	-1.99		0.20				-1.61						1.59			
SRB		-0.38		1.81	1.81		1.61			1.77		-0.47	-0.46			-0.29	
UKR						3.23							3.71		-1.13	3.88	-1.58
BGR					0.04			-1.77									
GRC	2.24				3.37												
HRV		0.09						0.47									
HUN								0.46	-3.71								
ITA							-1.59										
POL									1.13								
ROU						-0.65		0.29	-3.88								
SVK									1.58								

Figure 42: Differences in average annual wholesale electricity prices without new interconnection projects included: Business as Usual scenario in 2040 (€/MWh) [based on ref.3]

Country 1 / Country 2	ALB	BIH	GEO	XKX	MKD	MDA	MNE	SRB	UKR	BGR	GRC	HRV	HUN	ITA	POL	ROU	SVK
ALB				2.96	2.82		-0.83				2.51						
BIH							-0.59	1.83				-0.12					
GEO																	
XKX	-2.96				-0.14		-3.79	-1.37									
MKD	-2.82			0.14				-1.23		-0.91	-0.31						
MDA									-21.13							7.91	
MNE	0.83	0.59		3.79				2.42						-29.39			
SRB		-1.83		1.37	1.23		-2.42			0.32		-1.95	-0.31			-0.26	
UKR						21.13							28.99		8.78	29.04	33.47
BGR					0.91			-0.32									
GRC	-2.51				0.31												
HRV		0.12						1.95									
HUN								0.31	-28.99								
ITA							29.39										
POL									-8.78								
ROU						-7.91		0.26	-29.04								
SVK									-33.47								

Figure 43: Differences in average annual wholesale electricity prices without new interconnection projects included: ENTSO-E National Trends scenario in 2040 (€/MWh) [based on ref.3]

The National Trends in 2040 scenario results in a large number of borders with a wholesale price difference larger than 2 €/MWh, with the largest differences between Ukraine and Slovakia and Montenegro and Italy (the difference between Montenegro and Italy is almost 30 €/MWh[18]). Substantial differences are also visible at the border between Moldova and Ukraine and Ukrainian borders with Romania and Hungary. All critical borders with respect to the observed criterion are listed in the following table. Borders with a price difference larger than 2 €/MWh in at least one scenario in 2030 are marked in red, while borders with a price difference larger than 2 €/MWh in at least one scenario in 2040 are marked in green. Both colours indicate the borders where NTC values should be increased first. Potentially congested borders should be differentiated according to:

- the time frame when a significant price difference is expected (the shorter the time frame, the more critical it is);
- the number of scenarios in which the observed border is found to be critical/congested (the more scenarios found to be relevant, the lower the uncertainty of the results and the lower the risk associated with possible action to increase NTC); and
- the price differential value (the larger the value, the more action is needed to increase the NTC due to greater expected socio-economic welfare).

According to the PECI/PMI 2020 market simulation and the results presented in this chapter, the borders with the most significant potential for NTC increase are as follows:

- Ukraine – Poland/Slovakia/Hungary/Romania, because price differences larger than the threshold occur in 2030 and 2040 in both scenarios, reaching very high values up to 33 €/MWh;
- Moldova – Ukraine, as a price difference much larger than the threshold occurs in 2030 and 2040 in both analysed scenarios, reaching a very high value (21 €/MWh) in the ENTSO-E National Trends scenario in 2040;

[18] Description of the scenarios and assumptions may be found here.

- Moldova – Romania, because a price difference much larger than the threshold occurs in 2030 and 2040 in both analysed scenarios, reaching a very high value (14.5 €/MWh) in one scenario in 2030; and
- Montenegro – Italy, as a price difference larger than the threshold occurs in 2030 and 2040 in one scenario, reaching 29 €/MWh in 2040.

Table 25: Potentially congested borders in 2030 and 2040 and price differences larger than the threshold

BORDERS	Borders with price difference larger than 2 €/MWh			
	Business as Usual		ENTSO-E National Trends	
	2030	2040	2030	2040
Albania - Montenegro			5.30	
Albania - Greece		2.24		-2.51
Albania - Kosovo*				-2.96
Albania - N. Macedonia				-2.82
BiH - Croatia				
BiH - Serbia				
BiH - Montenegro				
Georgia - Russia				
Georgia - Azerbaijan				
Georgia - Armenia				
Georgia - Turkey				
Kosovo* - Serbia			3.54	
Kosovo* - Montenegro			4.56	3.79
Kosovo* - N. Macedonia				
Moldova - Ukraine		3.23	4.21	21.13
Moldova - Romania	-14.57			-7.91
N. Macedonia - Serbia			4.35	
N. Macedonia - Bulgaria				
N. Macedonia - Greece		3.37		
Montenegro - Albania				
Montenegro - Serbia				-2.42
Montenegro - Italy			2.96	29.39
Serbia - Croatia			2.06	
Serbia - Bulgaria			-5.03	
Serbia - Romania				
Serbia - Hungary				
Ukraine - Poland	-17.26		-8.53	-8.78
Ukraine - Slovakia	-14.23		-8.43	-33.47
Ukraine - Hungary	-15.30	-3.71	-8.20	-28.99
Ukraine - Romania	-15.30	-3.88	-9.92	-29.04
MAX	**17.26**	**3.88**	**9.92**	**33.47**

* red coloured: price difference larger than 2 €/MWh occurs in 2030
* green coloured: price difference larger than 2 €/MWh occurs in 2040

On all observed country borders, except those with Bosnia and Herzegovina, the price differences greater than 2 €/MWh that occur are usually either just above the threshold and, with a few exceptions, linked with just one scenario or time frame. The economic viability of projects linked to these borders is less likely to be positive within a cost benefit analysis.

The presented results show that the NTC values at all borders should be re-evaluated and potentially increased, or markets should be coupled, in order to fully benefit from market competition.

Increasing NTC values should be done by different means, starting with the fastest and cheapest options. The construction of new cross-border infrastructure projects should be considered last, as they are the most time-demanding and probably the most expensive option.

The selection of new interconnection projects shall be based on their economic viability, which will be assured:

- if a large price difference exists between the two areas intended to be connected with a new transmission line,
- if that difference exists over a longer period of time and
- if that difference occurs in different scenarios which represent future uncertainties.

5.2.2 Ratio between nominal transmission capacity of interconnectors and peak load

The worst-case ratios between the nominal transmission capacity of interconnectors and expected peak load in 2030 and 2040 for the EnC CPs are shown in the following tables (Table 26, Table 27). The calculations were performed by taking into account the nominal transmission capacity of existing interconnectors (planned ones are not taken into calculation for the worst-case scenario) and the maximum forecast of a country's peak load related to the observed time frame. Numbers in the tables are marked in red if they are smaller than 30 % and in purple if they are between 30 % and 60 %, following the recommendations described in Chapter 2.2.2.

The only country that might face difficulties meeting this criterion is Ukraine, due to the limited number of interconnectors toward the ENTSO-E countries (the ones to Russia and Belarus were not taken into account although they exist and will probably be ready for emergency usage following Ukrainian synchronisation with the ENTSO-E) and the relatively high peak load assumptions in the worst-case scenario (27 GW in 2030 and 53 GW in 2040). Ukraine's worst-case ration is thus 31 % in 2030, which might fall to 16 % in 2040 if peak load goes up to 53 GW.

Table 28 and Table 29 present the results of the sensitivity analysis depending on the future situation with interconnectors and peak load.

The "worst-case scenario" is the one in which no new interconnectors are constructed and maximum peak load is assumed. The "planned scenario" is the one in which TSO's construct new interconnectors according to their plans and peak load reaches the average between minimum and maximum forecasts. The "best scenario" is the one in which all new interconnectors are in place and peak load reaches the minimum forecasted value.

Table 26: EnC CPs' compliance with the 2030 interconnectivity targets (the worst-case scenario)

Country	2030 interconnectivity targets (the worst-case scenario)		
	Wholesale market price difference criterion	Peak load criterion (nominal transmission capacity of interconnectors in 2020)	Renewables criterion (nominal transmission capacity of interconnectors in 2020)
ALB	border to **Montenegro** (ENTSO-E National Trends scenario)	274%	136%
BIH	None	338%	143%
GEO	could not be estimated	61% (**33%** according to GSE data)	**47%** (**25%** according to GSE data)
XKX	border to **Montenegro** and **Serbia** (ENTSO-E National Trends scenario)	368%	317%
MKD	border to **Serbia** (ENTSO-E National Trends scenario)	378%	217%
MDA	border to **Romania** (BAU scenario) and to **Ukraine** (ENTSO-E National Trends scenario)	203%	163%
MNE	border to **Albania**, **Kosovo*** and **Italy** (ENTSO-E National Trends scenario)	714%	339%
SRB	borders to **Kosovo*, N.Macedonia, Bulgaria** and **Croatia** (ENTSO-E National Trends scenario)	146%	100%
UKR*	borders to **Poland**, **Slovakia**, **Hungary** and **Romania** (both scenarios), border to **Moldova** (ENTSO-E National Trends scenario)	**31%**	**24%**

* connected to the ENTSO-E network

Table 27: EnC CPs' compliance with the 2040 interconnectivity targets (the worst-case scenario)

Country	2040 interconnectivity targets (the worst-case scenario)		
	Wholesale market price difference criterion	Peak load criterion (nominal transmission capacity of interconnectors in 2020)	Renewables criterion (nominal transmission capacity of interconnectors in 2020)
ALB	border to **Greece** (BAU scenario) and borders to **Kosovo***, **N. Macedoni**a and **Greece** (ENTSO-E National Trends scenario)	274%	82%
BIH	None	337%	106%
GEO	could not be estimated	peak load prediction unknown	**47%** (**25%** according to GSE data)
XKX	border to **Albania** and **Montenegro** (ENTSO-E National Trends scenario)	peak load prediction unknown	312%
MKD	border to **Greece** (BAU scenario) and border to **Albania** (ENTSO-E National Trends scenario)	353%	217%**
MDA	border to **Ukraine** (BAU scenario) and borders to **Romania** and **Ukraine** (ENTSO-E National Trends scenario)	peak load prediction unknown	163%**
MNE	border to **Kosovo***, **Serbia** and **Italy** (ENTSO-E National Trends scenario)	586%	187%
SRB	border to **Montenegro** (ENTSO-E National Trends scenario)	125%	100%**
UKR*	borders to **Moldova**, **Hungary** and **Romania** (BAU scenario), borders to **Moldova**, **Hungary**, **Poland, Slovakia** and **Romania** (ENTSO-E National Trends scenario)	**16%**	**24%****

* connected to the ENTSO-E network

** the same value as in 2030 based on assumptions described in Chapter 4.6

Table 28: Ratio between nominal transmission capacity of interconnectors and the peak load (sensitivity analysis 2030)

Country	Peak load criterion in 2030		
	worst-case scenario*	Planned scenario**	best scenario***
ALB	274%	274%	274%
BIH	338%	452%	460%
GEO	61% (33% according to GSE data)	169% (118% according to GSE data)	270% (188% according to GSE data)
XKX	368%	402%	442%
MKD	378%	415%	406%
MDA	203%	353%	353%
MNE	714%	1074%	1134%
SRB	146%	246%	331%
UKR	**31%**	**55%**	64%

* existing interconnectors only, maximum prediction of the peak load in the future
** existing and planned interconnectors included, average prediction of the peak load in the future
** existing and planned interconnectors included, the lowest prediction of the peak load in the future

Table 29: Ratio between nominal transmission capacity of interconnectors and the peak load (sensitivity analysis 2040)

Country	Peak load criterion in 2040		
	worst-case scenario*	planned scenario**	best scenario***
ALB	274%	274%	274%
BIH	337%	448%	451%
GEO	peak load prediction unknown	peak load prediction unknown	peak load prediction unknown
XKX	peak load prediction unknown	peak load prediction unknown	peak load prediction unknown
MKD	353%	391%	438%
MDA	peak load prediction unknown	peak load prediction unknown	peak load prediction unknown
MNE	586%	935%	1361%
SRB	125%	224%	321%
UKR	**16%**	**32%**	**46%**

* existing interconnectors only, maximum prediction of the peak load in the future
** existing and planned interconnectors included, average prediction of the peak load in the future
** existing and planned interconnectors included, the lowest prediction of the peak load in the future

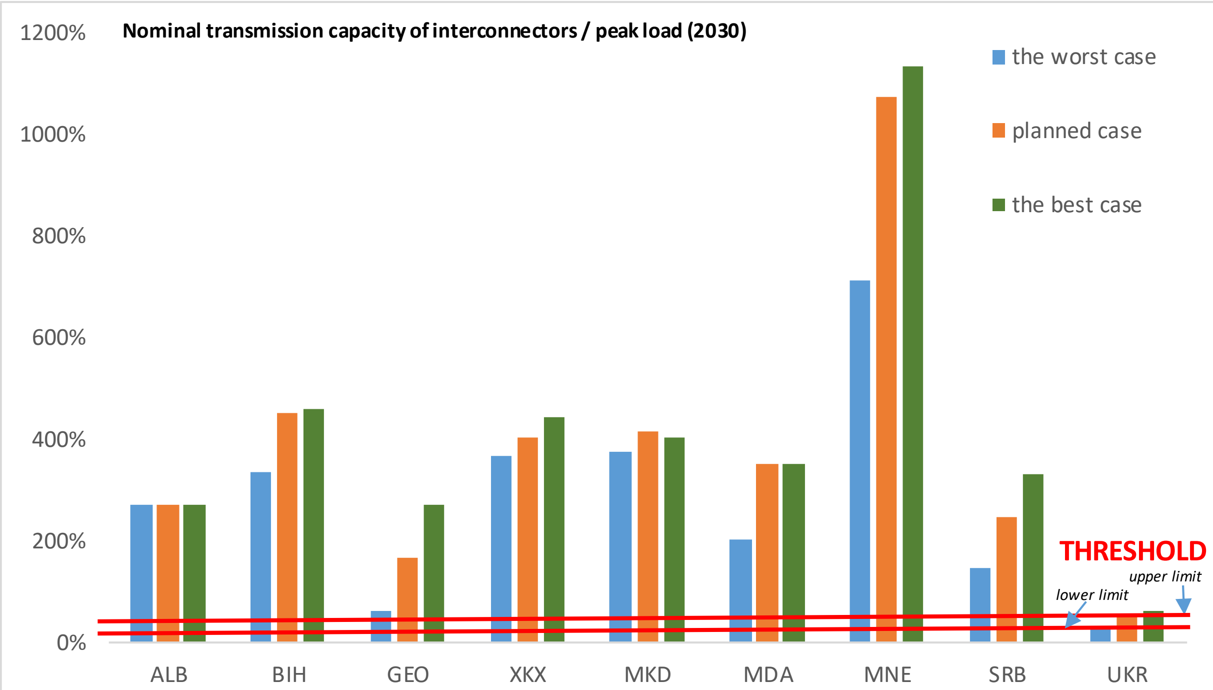


Figure 44: Peak load related interconnectivity target fulfilment in 2030

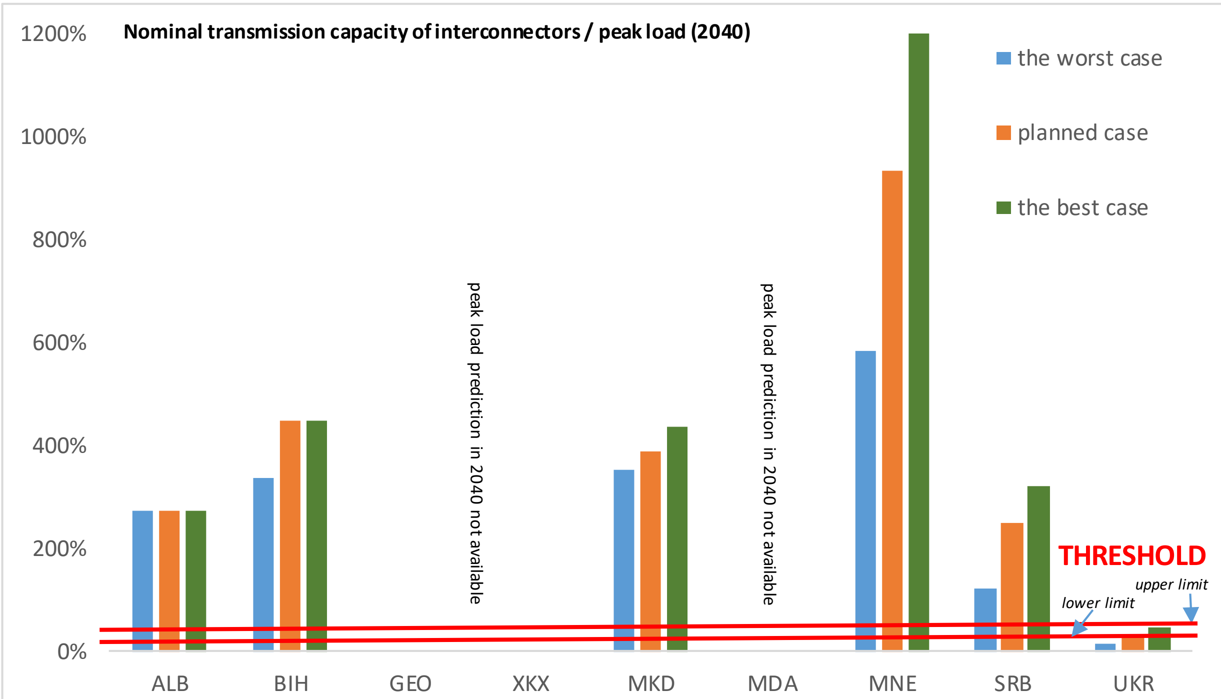


Figure 45: Peak load related interconnectivity target fulfilment in 2040

Ukraine is the only country not completely fulfilling the observed criterion. Its ratio spans from 31 % to 64 % in 2030. In 2040, this range is between 16 % and 46 %, which means that additional interconnectors (beside the ones already planned) might be necessary in the long term, depending on the peak load values.

The other eight countries satisfy the observed criterion in both time frames no matter the other assumptions.

Due to a high peak load increase in Georgia in the worst-case scenario, this ratio may come down to 61 %, which is still above the critical range between 30 % and 60 %. If GSE data on the nominal transmission capacity of the interconnectors are used (with heavily restricted maximum permitted loading of the 500 kV lines toward Russia and Azerbaijan), this ratio may drop down to 33 %.

The third eastern country, Moldova, has this ratio far above the critical value.

The WB6 countries have significantly higher values than the 30 % to 60 % threshold, even in the worst-case scenario. Among the WB6, the observed ratio is the lowest in Serbia (between 146 % and 331 % in 2030 and between 125 % and 321 % in 2040) and the highest in Montenegro (between 714 % and 1134 % in 2030 and between 586 % and 1361 % in 2040).

5.2.3 Ratio between nominal transmission capacity of interconnectors and installed renewable generation

The worst-case ratio between the nominal transmission capacity of interconnectors and the expected level of renewable energy sources are shown in the previous tables (Table 26, Table 27).

Numbers in the tables are marked in red if they are smaller than 30 % and in purple if they are between 30 % and 60 %, following the recommendations described in Chapter 2.2.3.

The only countries which might face difficulties meeting this criterion are Ukraine and Georgia, due to the limited number of existing interconnectors and relatively high maximum expected renewables integration levels in 2030 and 2040 as described in Chapter 4.6.

Table 30 and Table 31 present the results of the sensitivity analysis based on three scenarios with different assumptions linked to interconnectors and the level of RES integration.

The “worst-case scenario” is the one in which no new interconnectors are constructed and maximum forecasted RES values are used.

The “planned scenario” is the one in which TSOs construct new interconnectors according to their plans and the average between the minimum and maximum forecasts for installed renewable generation is used.

The “best scenario” with respect to the interconnectivity targets is the one in which all new interconnectors are in place and RES are integrated according to the minimum predicted value in order to reach the maximum ratio between the two values.

Ukraine has the observed ratio in the range of 24 % to 81 % in 2030. In 2040, this range is within 24 % and 60 %, meaning that large-scale integration of RES might require the construction of new interconnectors.

Georgia has the observed ratio in the range of 48 % to 190 % in 2030 (from 25 % to 126 % according to the GSE data on maximum permitted loading of the existing 500 kV lines). In 2040, this range is within 48 % and 140 % (25 % and 93 % according to the GSE data)[19].

The other seven countries satisfy the observed criterion in both time frames no matter the other assumptions.

Moldova has the observed ratio above 163 %. All WB6 countries have rations significantly higher than the threshold values of 30 % and 60 %, reaching more than 100 % even in the worst-case scenario in which no new interconnectors have been put in service.

Although this interconnectivity target will have to be re-evaluated as new RES integration plans take shape, especially when NECPs have been adopted, there are no serious concerns about the ability of cross-border lines to support the large-scale integration of renewables at this point in time, at least in eight out of the nine CPs.

Table 30: Ratio between nominal transmission capacity of interconnectors and installed power of RES (sensitivity analysis 2030)

Country	Renewables criterion in 2030		
	worst-case scenario*	planned scenario**	best scenario***
ALB	136%	146%	153%
BIH	143%	317%	328%
GEO	48% (25% according to GSE data)	131% (86% according to GSE data)	190% (126% according to GSE data)
XKX	317%	767%	842%
MKD	217%	357%	373%
MDA	163%	841%	913%
MNE	339%	433%	457%
SRB	100%	227%	239%
UKR	24%	71%	81%

* existing interconnectors only, maximum prediction of RES integration in the future
** existing and planned interconnectors included, average prediction of RES integration in the future
** existing and planned interconnectors included, the lowest prediction of RES integration in the future

[19] It shall be mentioned that the biggest share of RES in Georgia are hydro power plants with a large amount of accumulation/storage. Accumulation hydro power plants are not intermittent renewable energy sources like wind power plants or solar power plants and their impact on the usage of interconnectors can be controlled (in the vast majority of situations they may decrease or increase production when interconnectors are heavily loaded without spilling water, thus relieving them). That is why Georgia will probably not face problems with respect to RES integration no matter the defined interconnectivity targets, especially if it renews the existing 500 kV lines to Russia and Azerbaijan.

Table 31: Ratio between nominal transmission capacity of interconnectors and installed power of RES (sensitivity analysis 2040)

Country	Renewables criterion in 2040		
	worst-case scenario*	planned scenario**	best scenario***
ALB	82%	87%	93%
BIH	106%	163%	194%
GEO	**48%** (**25%** according to GSE data)	116% (77% according to GSE data)	140% (93% according to GSE data)
XKX	312%	456%	842%
MKD	217%	240%	264%
MDA	163%	496%	529%
MNE	187%	246%	268%
SRB	100%	193%	193%
UKR	**24%**	**59%**	**60%**

* existing interconnectors only, maximum prediction of RES integration in the future
** existing and planned interconnectors included, average prediction of RES integration in the future
** existing and planned interconnectors included, the lowest prediction of RES integration in the future

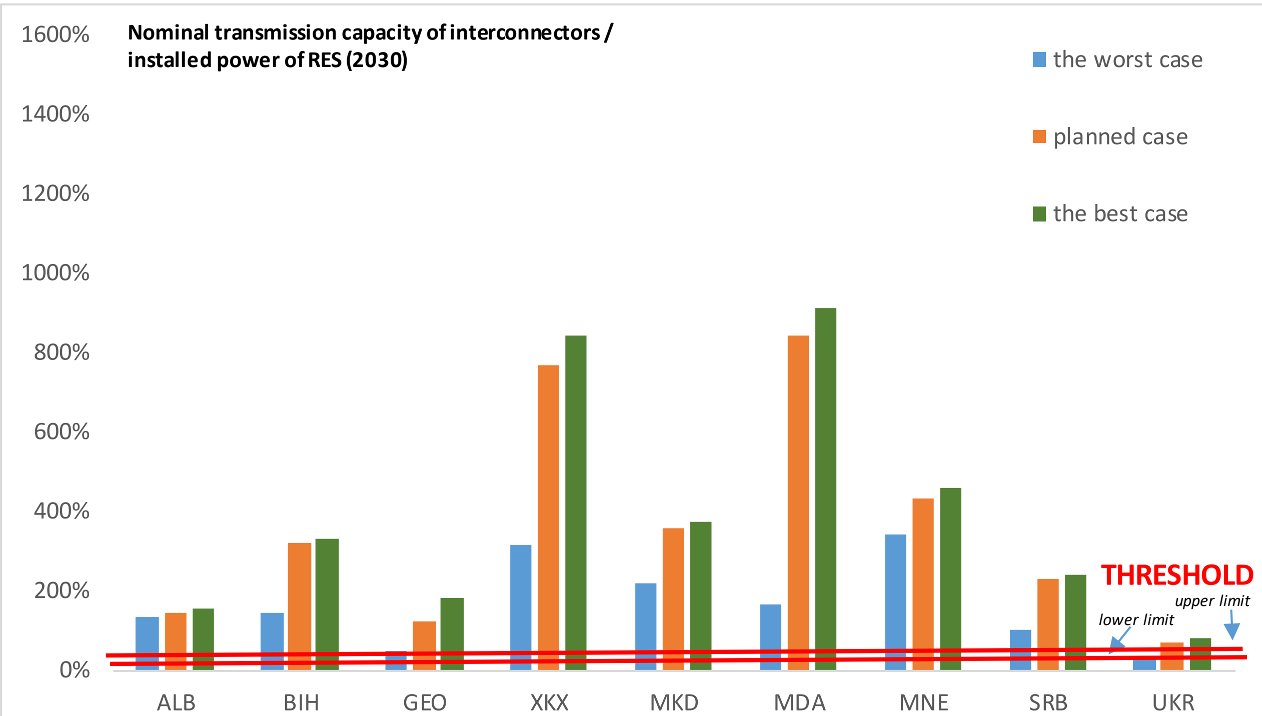


Figure 46: RES related interconnectivity target fulfilment in 2030

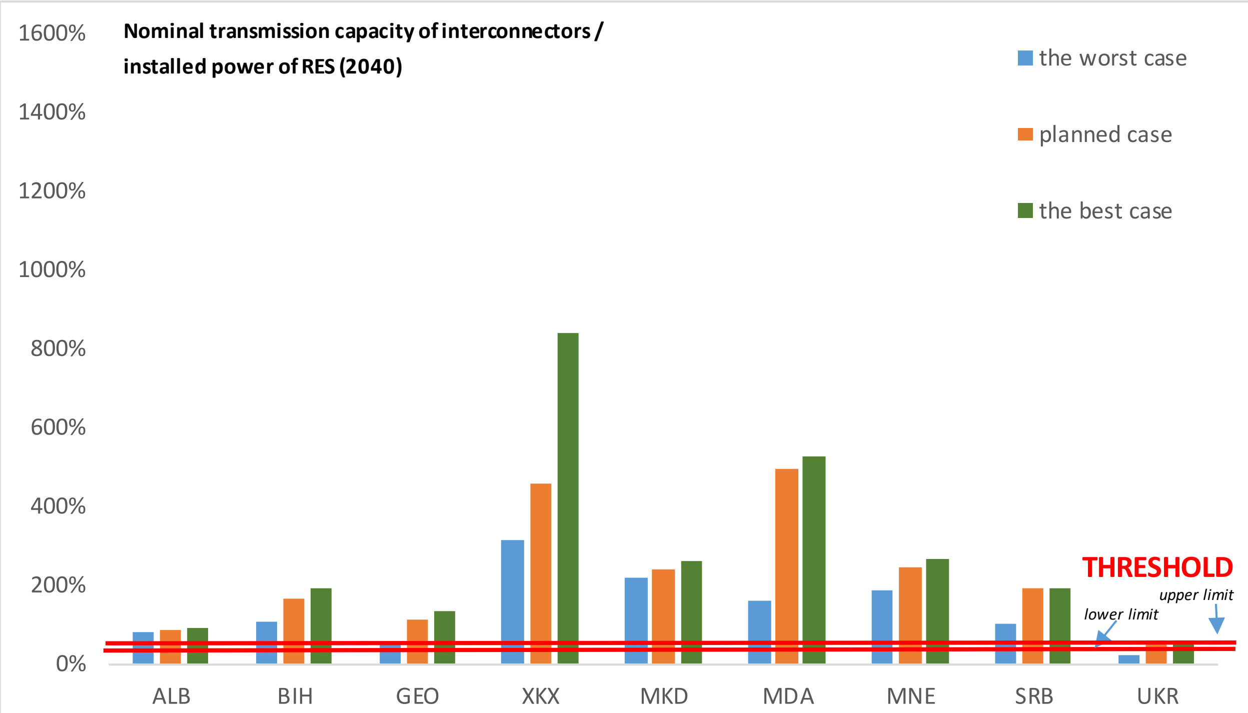


Figure 47: RES related interconnectivity target fulfilment in 2040

6 Conclusions and recommendations

This study analysed the Energy Community Contracting Parties' compliance with the 2020 and 2030 EU interconnectivity targets. While these targets are not yet legally binding for the CPs, they represent useful benchmarks to examine the readiness of the electricity transmission systems for the low-carbon energy sector transition and other electricity market developments in the observed area. Electricity transmission systems will play a significant role in this transition in order to enable large-scale integration of renewables, system flexibility, full market competition and a high level of security of electricity supply.

The EU interconnectivity targets relate to the 10 % criterion in 2020 (10% of net transfer capacity with respect to total production capacity) and the 15 % criterion in 2030, defined through three sub-criteria as follows:

- the wholesale price difference between two bidding zones should be lower than 2 €/MWh; the larger the difference, the greater the need for action;
- the ratio between nominal transmission capacity of interconnectors and peak load should be higher than 30 %; if lower, urgent action is needed. TSOs should consider additional cross-border reinforcements if this ratio is between 30 % and 60 %; and
- the ratio between nominal transmission capacity of interconnectors and installed renewables generation capacity should also be higher than 30 %; if lower, urgent action is needed. TSOs should consider additional cross-border reinforcements if this ratio is between 30 % and 60 %.

Beside these three sub-criteria, the issue of economic viability of new cross-border interconnection lines is of the utmost importance, meaning that new projects should only be implemented if the potential benefits outweigh the costs. Based on the above, the following conclusions can be drawn:

- The transmission networks of the EnC CPs are more strongly interconnected than those of the majority of EU MS today (in relation to the peak load and installed generation capacity). All observed countries comfortably satisfy the 10 % interconnectivity target, only Ukraine is close to or below this threshold depending on what part of the country is observed (Burshtyn island only or the whole of Ukraine) and which cross-border transmission lines are taken into account (toward ENTSO-E or UPS/IPS or both).

- The nominal transmission capacity of the interconnectors is in the vast majority of observed countries much higher than the peak load or total installed capacity of generators, meaning that significant electricity imports and exports in and out of each CP are theoretically possible.

- Market integration in the WB6 area is not hindered by the lack of interconnectors. However, they are not used in the most efficient way due to two main reasons; (1) absence of coordinated capacity calculation and (2) absence of an efficient mechanism to allocate and use capacity (market coupling).

- Efficient usage and full exploitation of interconnectors is unfortunately still an issue due to low NTC values at the borders, leading to restricted market activities in the observed regions. The restricted NTC values are, however, sufficient to meet the EU interconnectivity target in 2020, but without going significantly above it even though it may be possible using the existing cross-border infrastructure.

- Western Balkan countries are strongly interconnected, with the maximum ratio between NTC values and installed production capacity in the range of 50 % (Bosnia and Herzegovina and Serbia) to 210 % (Montenegro).

- Eastern Contracting Parties (Moldova and Ukraine) are mutually very strongly interconnected with seven 330 kV lines but import to Moldova from Ukraine is heavily restricted, thus negatively influencing market competition in both countries. Georgia has strong interconnections with its neighbouring countries (except Armenia with only one 220 kV line). However, the country is situated in between three synchronous areas and the Georgian internal network cannot fully support a very high level of exchanges. Since GSE heavily restricts permitted loading of the existing 500 kV lines to Russia and Azerbaijan, the exchange possibilities between Georgia and Russia/Azerbaijan are limited, thus potentially creating needs for the construction of additional cross-border lines. Revitalisation of the existing 500 kV lines should also be considered in order to increase the transmission capacities of Georgia toward its neighbours.

- The wholesale electricity market price criterion in 2030 and 2040 is observed in this study with respect to the market simulations performed during the PECI/PMI selection process in 2020, without new interconnectors included and with the existing (restricted) NTC values between countries. Results show that differences larger than 2 €/MWh may be expected for some borders in certain scenarios depending on future generation development, integration of RES and demand increase, but are also heavily dependent on the utilisation of existing interconnectors. The borders that could benefit the most from increasing the NTC are the ones between Ukraine and Hungary, Ukraine and Poland, Ukraine and Slovakia, Ukraine and Romania, Ukraine and Moldova, Moldova and Romania and Montenegro and Italy.

It should be stressed that the wholesale market price difference criterion is one of the most efficient indicators of the economic viability of new interconnection projects, but this assumes that the existing interconnectors are fully utilised (high NTC values, closer to the nominal transmission capacity of the interconnectors) and market activities are not unnecessarily restricted. A cost-benefit analysis of any new cross-border projects should be performed with an assumption of the existing interconnectors being fully utilized (by applying the highest possible NTC values in the calculations). Such an approach would more clearly identify the real necessity for new interconnectors. Otherwise, the non-efficient usage of the existing interconnectors and low NTC values may be misleading, wrongly justifying new projects without considering faster and cheaper options, which may be available to efficiently increase the exchange possibilities between bidding zones/countries.

- The other two sub-criteria to measure the interconnectivity level and compliance with the 2030 targets, the ratio between nominal transmission capacity of the interconnectors and peak load and the ratio between nominal transmission capacity of the interconnectors and installed renewables generation capacity, are going to be fulfilled for the vast majority of observed countries even with the existing number and transmission capacity of interconnectors.

- The results of the study clearly indicate that national regulatory authorities and transmission system operators should increase their focus on the **efficient usage of the existing interconnectors**. **New cross-border projects should only be developed if existing interconnectors would not be capable of fully supporting market activities in the future.**

- Setting low NTC values allows TSOs to collect higher congestion rents, which represent an additional financial resource used to decrease transmission fees or finance additional investments. In such circumstances, the motivation for increasing the NTC values is negatively impacted by concerns over the loss of this revenue. On the other side, the nominal transmission capacity of the CPs' interconnectors (at least the vast majority of them) is larger than the peak load values and/or total installed generation capacities. In spite of that, the EnC CPs still develop new cross-border transmission infrastructure projects and nominate them to be on the PECI/PMI and PCI lists without properly addressing internal network bottlenecks which restrict the NTC values. Such an approach raises concerns as cross-border investments are usually several times costlier than limited-size internal investments.

Recommendations of this study are as follows:

- NTC values at all borders should be re-evaluated, calculated more frequently through coordinated processes and potentially increased, and/or markets should be coupled in order to fully benefit from market competition.

- Increasing the NTC values is one of the most important actions to support the integration of renewables and decarbonisation of the electricity sectors. NRAs should be more active in this respect by obliging TSOs to identify critical network elements which restrict the NTC values and to propose solutions to relieve internal bottlenecks.

- Increasing the NTC values should be done by different means, starting with the fastest and cheapest options (coordinated capacity calculation, improvement of network models, re-evaluation of the transmission reliability margins, day-ahead and intraday calculations, re-dispatching and countertrading if economically justified etc.).

- The NTC values should be further increased by reinforcing the internal networks (where internal congestion limits the NTC) through different actions based on the lowest cost approach (application of dynamic thermal rating on critical lines, revitalisation of lines by using high temperature low sag conductors HTLS, construction of new internal transmission facilities), and only as the last possibility consider the construction of new cross-border infrastructure projects, as the most time demanding and probably the most expensive option.

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ANNEX: Interconnectivity targets compliance in 2020, 2030 and 2040

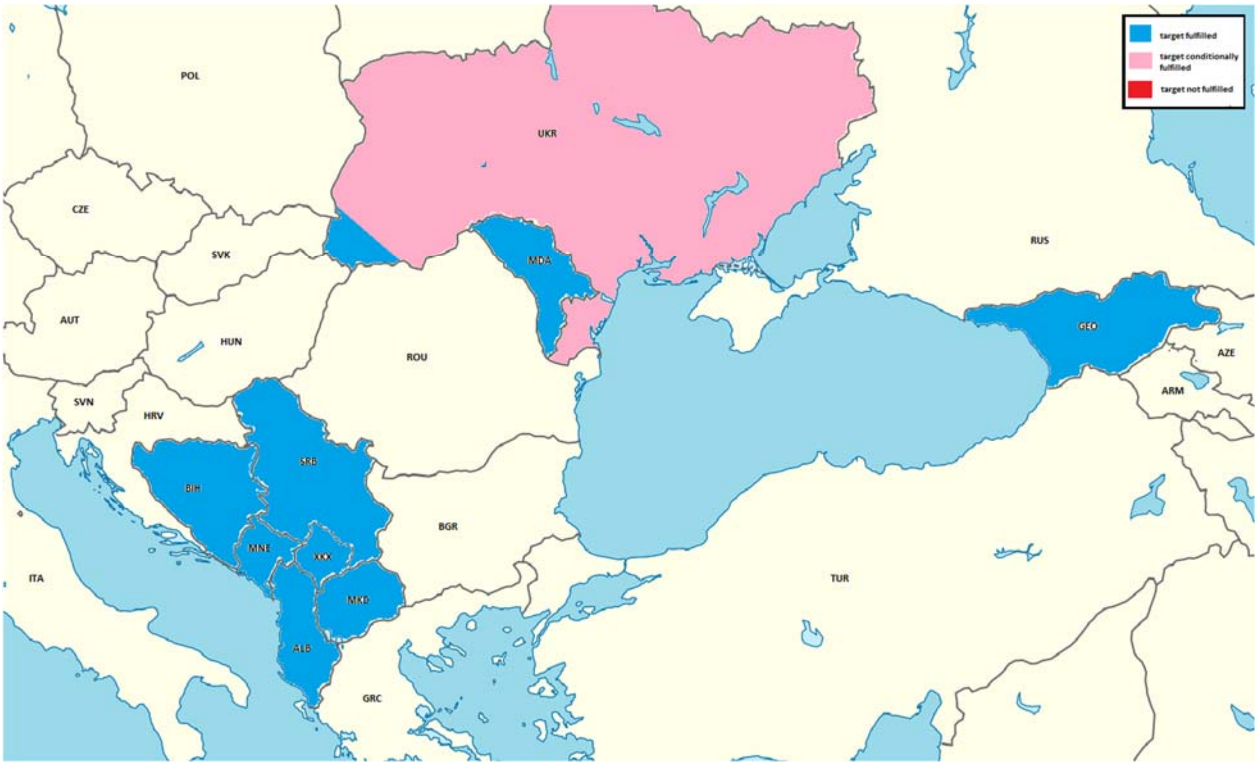

Figure 48: Interconnectivity target compliance in 2020

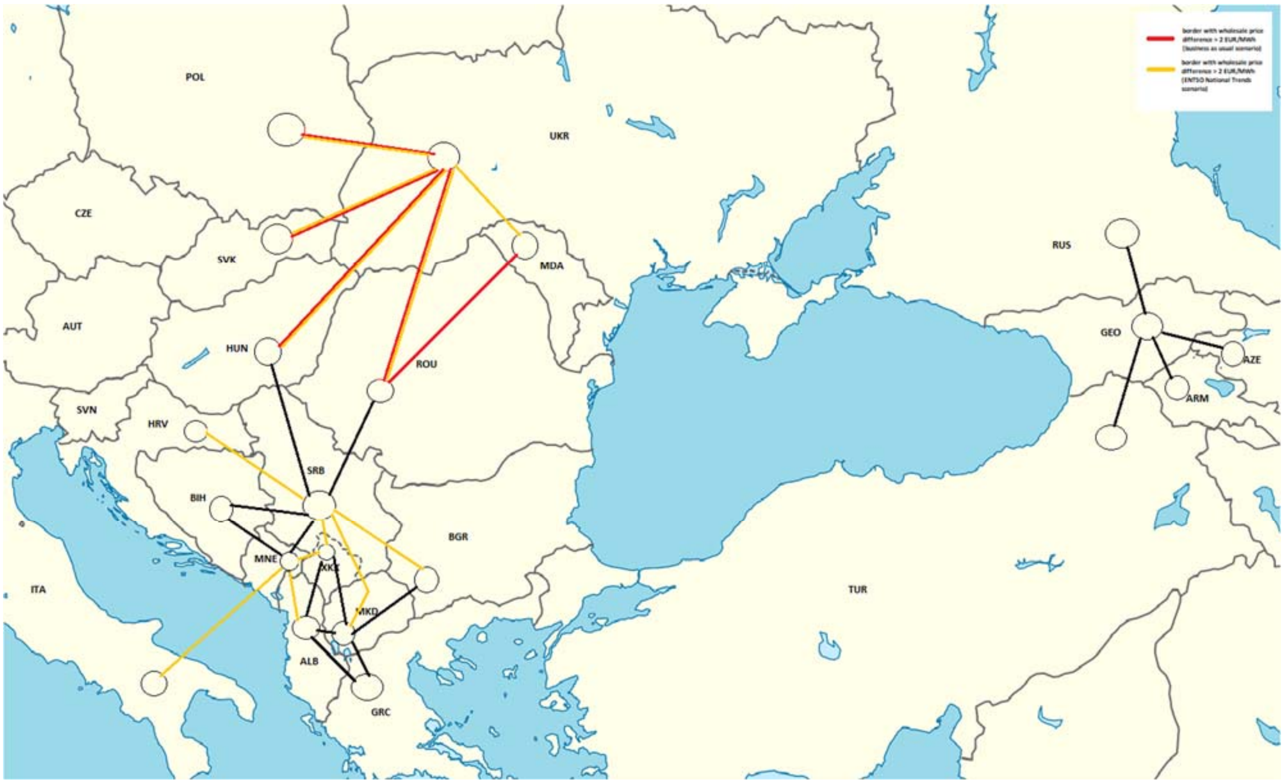

Figure 49: Interconnectivity targets compliance in 2030 (the wholesale electricity price difference criterion)

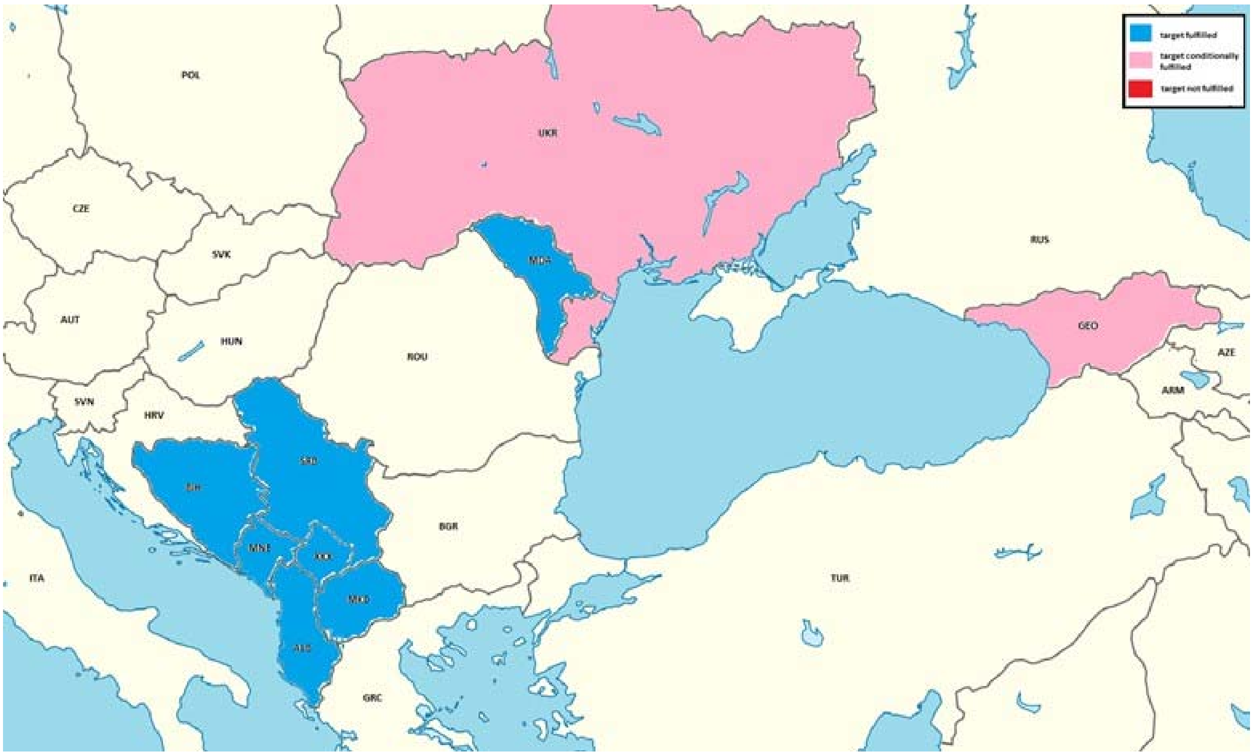

Figure 50: Interconnectivity targets compliance in 2030 (ratio between nominal transmission capacity of interconnectors and peak load criterion)

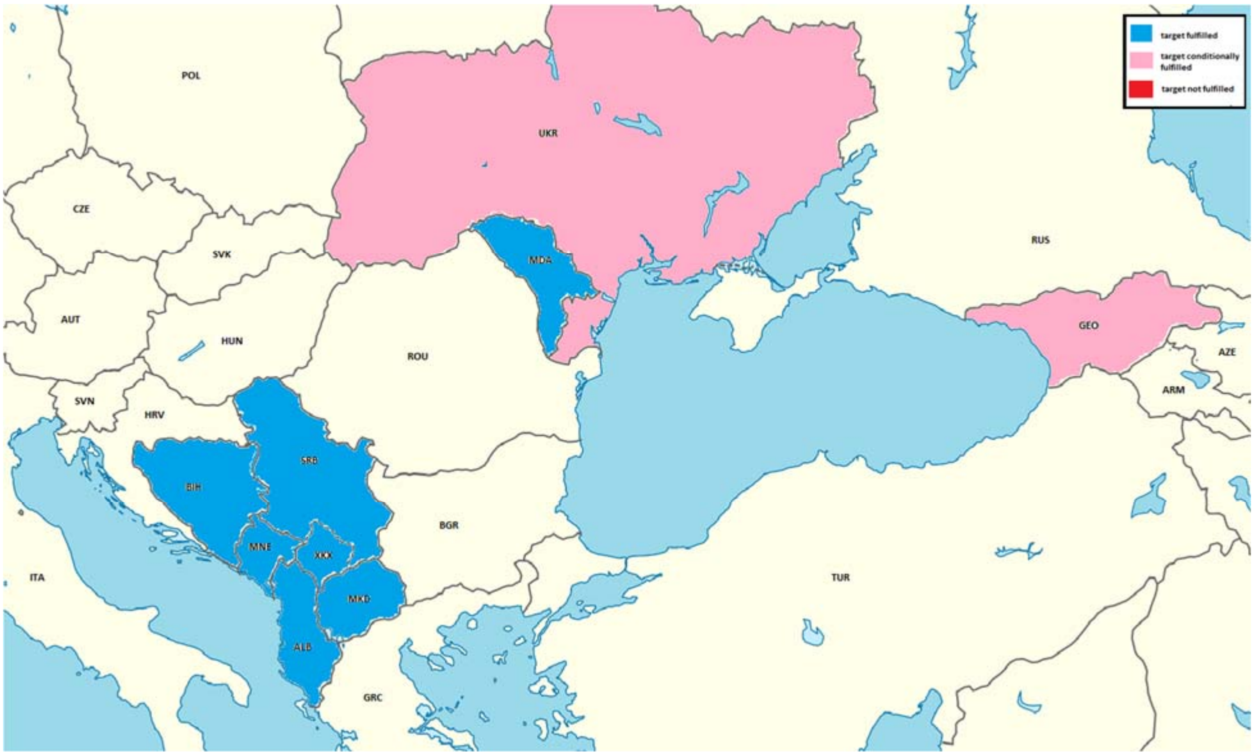

Figure 51: Interconnectivity targets compliance in 2030 (ratio between nominal transmission capacity of interconnectors and installed renewable generation criterion)

Figure 52: Interconnectivity targets compliance in 2040 (wholesale electricity prices difference criterion)

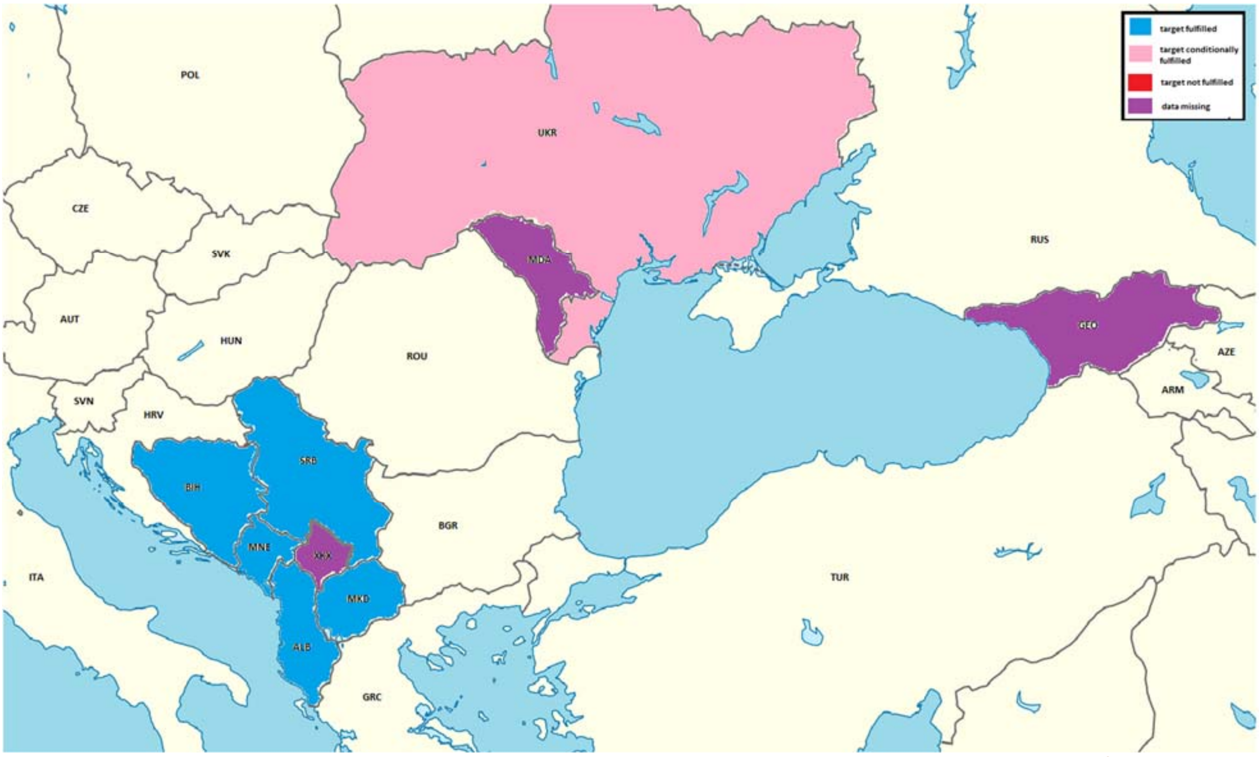

Figure 53: Interconnectivity targets compliance in 2040 (ratio between nominal transmission capacity of interconnectors and peak load criterion)

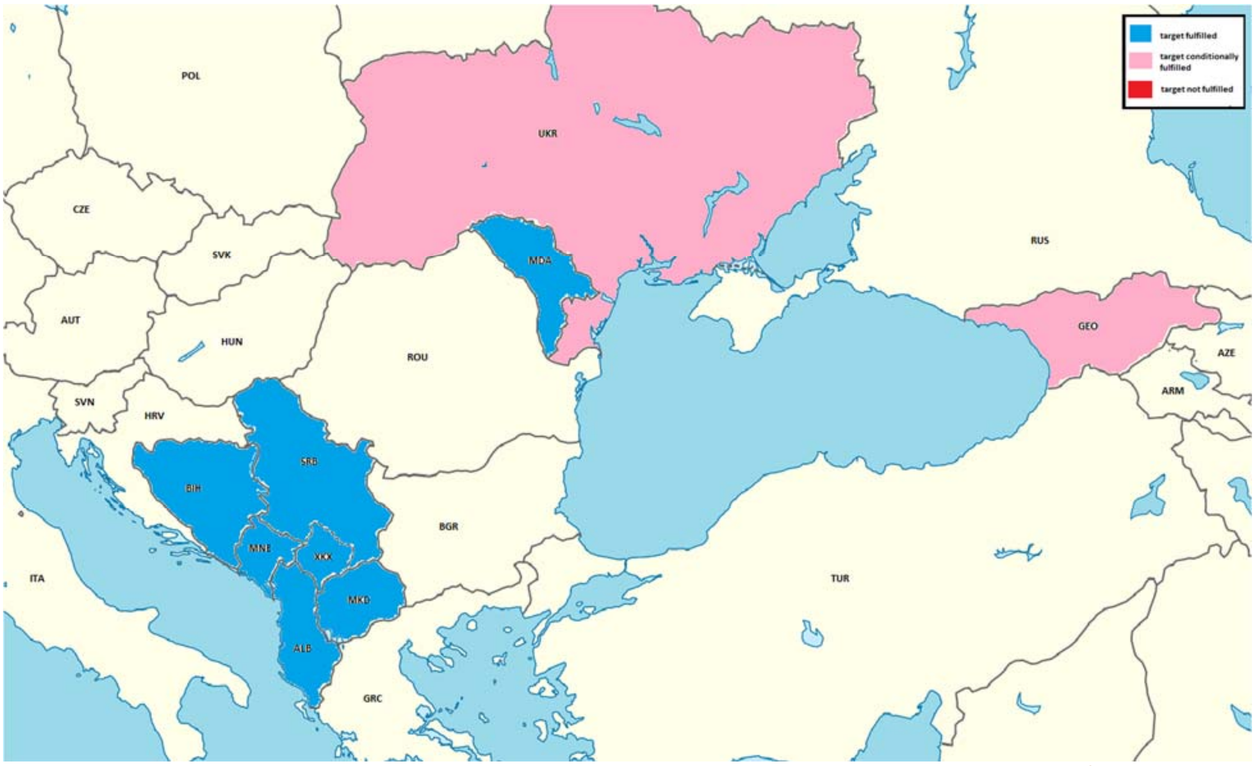

Figure 54: Interconnectivity targets compliance in 2040 (ratio between nominal transmission capacity of interconnectors and installed renewable generation criterion)