State of electricity day-ahead, intraday and balancing markets in the Energy Community in 2023

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Introduction

1. About the Energy Community and the Energy Community Regulatory Board

The Energy Community[1] is an international organisation established in 2006 with the aim to bring together the European Union and its neighbours to create an integrated pan-European energy market. The key objective of the Energy Community is to extend the EU internal energy market rules and principles to countries in South East Europe, the Black Sea region and beyond, based on a legally binding framework. Currently, the Energy Community has nine Contracting Parties: Albania (AL), Bosnia and Herzegovina (BA), Georgia (GE), Kosovo*[2] (XK*), Moldova (MD), Montenegro (ME), North Macedonia (MK), Serbia (RS) and Ukraine (UA), while Armenia (AM), Turkey (TR) and Norway (NO) are Observer Countries.[3]

As a body of the Energy Community, the Energy Community Regulatory Board (ECRB) operates based on Article 58 of the *Treaty establishing the Energy Community*. The ECRB advises the Energy Community Ministerial Council and Permanent High Level Group on details of statutory, technical and regulatory rules and makes recommendations in the case of cross-border disputes between regulators. The ECRB is the independent regional voice of energy regulators in the Energy Community. The ECRB's mission builds on three pillars: providing coordinated regulatory positions to energy policy debates, harmonizing regulatory rules across borders and sharing regulatory knowledge and experience. Additionally, after the adoption of the Electricity Integration Package[4] in December 2022, ECRB gained numerous new competencies, including decision-making powers concerning the approval of the regional terms and conditions or methodologies. Thus, this package made the ECRB an important institution for enabling the market integration of the Energy Community Contracting Parties into the single EU market.

2. Background

As a part of the previously mentioned Electricity Integration Package, the adapted versions of *Regulation 2019/943 on the internal market for electricity* (EnC Electricity Regulation), *Regulation 2015/1222 establishing a guideline on capacity allocation and congestion management* (EnC CACM Regulation) and *Regulation 2017/2195 establishing a guideline on electricity balancing* (EnC EBGL Regulation) became a part of the Energy Community acquis, setting the binding requirement for the Energy Community Contracting Parties to transpose these legal acts for day-ahead, intraday and balancing markets to their national legislations.

The EnC CACM Regulation defines the harmonized legal framework for the functioning of Single Day-ahead Coupling (SDAC) and Single Intraday Coupling (SIDC), enabling the adherence of the Energy Community Contracting Parties' bidding zones to the integrated EU electricity market. In particular, SDAC and SIDC are based on simultaneous order matching and capacity allocation allowing for more efficient use of the network and increasing competition for the benefit of consumers. The EnC Electricity Regulation complements the EnC CACM Regulation by defining additional requirements to facilitate trade on day-ahead and intraday markets.

Since some Energy Community Contracting Parties have established day-ahead and intraday markets

[1] https://www.energy-community.org/
[2] Throughout this document the symbol * refers to the following statement: This designation is without prejudice to positions on status, and is in line with UNSCR 1244 and the ICJ Advisory Opinion on the Kosovo* declaration of independence.
[3] https://www.energy-community.org/aboutus/whoweare.html
[4] https://www.energy-community.org/implementation/package/EL.html

and started early implementation of the CACM Regulation even before the EnC CACM was adopted, this report aims to present the current status of these markets and their progress towards the implementation of EnC CACM Regulation.

On the other hand, the EnC EBGL Regulation introduces a set of minimum harmonized rules to govern the functioning of the electricity balancing markets, including the procurement of balancing services, the financial settlement of balance responsible parties and imbalance settlement. Additionally, EnC EBGL sets a requirement for the transmission system operators of Contracting parties to use the European platforms for the exchange of balancing energy, enabling balancing energy bids from Contracting Parties to compete on European-wide balancing platforms. The Energy Community Contracting Parties have established balancing mechanisms that are to some extent aligned with the harmonized framework set by EnC EBGL Regulation. Having this in mind, this report aims to provide a high-level description of the balancing market in the Energy Community Contracting Parties and emphasize the main requirements from EnC EBGL Regulation and EnC Electricity Regulation related to balancing that will have to be met after the transposition of these regulations into the national legal systems of Contracting Parties.

3. Methodology and scope

The present report consists of three major parts:

1. The first part analyses the day-ahead market and day-ahead cross-zonal capacity allocation.
2. The second part addresses intraday market and relevant cross-zonal capacity allocation in CPs, while
3. The third chapter provides information on the balancing markets and imbalance price formation in the CPs.

The first two parts of this report investigate the current level of development of day-ahead and intraday markets and to what extent the gate closure times are harmonized amongst CPs. The third part of the report describes the main features of balancing markets in CPs, namely, the procurement of balancing capacity, the provision of balancing energy and the settlement of balance responsible parties. More details on balancing market particularities in several CPs are provided in Annex II in the form of case studies.

The information presented reflects the state of development in the CPs in the first half of 2023, while some major updates from 2024 are also presented in this report.

The information displayed in this report is based on data provided by the EnC NRAs, namely: the Energy Regulatory Authority of Albania (ERE), State Electricity Regulatory Commission of Bosnia and Herzegovina (SERC), Georgian National Energy and Water Supply Regulatory Commission (GNERC), Energy Regulatory Office of Kosovo* (ERO), National Agency for Energy Regulation of the Republic of Moldova (ANRE), Energy and Water Regulatory Agency of Montenegro (REGAGEN), Energy and Water Services Regulatory Commission of North Macedonia (ERC), Energy Agency of the Republic of Serbia (AERS) and National Energy and Utilities Regulatory Commission (NEURC).

This report in Annex III additionally covers the state of Armenia's wholesale electricity market, based on the information, provided by the NRA – Public Services Regulatory Commission of the Republic of Armenia (PSRC). Currently, Armenia has an observer status in EnC.

4. Acronyms

aFRR	Automatic Frequency Restoration Reserve
ATC	Available Transfer Capacity
BRP	Balance responsible party
BSP	Balancing service provider
CP	Contracting Party
DA	Day-ahead
D-1	One day before the delivery day
D-3	Three days before the delivery day
D-7	Seven days before the delivery day
GCT	Gate closure time
GOT	Gate opening time
H-1	One hour before the delivery hour/ the start of the first hour to which the intraday cross-border transaction relates
H-90 minutes	90 minutes before the delivery hour/ the start of the first hour to which the intraday cross-border transaction relates
ID	Intraday
ISP	Imbalance settlement period
LFC	Load frequency control
mFRR	Manual Frequency Restoration Reserve
MoU	Memorandum of Understanding
UIOLI	Use-It-or-Lose-It principle
RES	Renewable energy sources
RR	Replacement reserve
SDAC	Single day-ahead coupling
SIDC	Single intraday coupling
TSO	Transmission System Operator
KOSTT	Transmission System Operator in Kosovo*
EMS	Transmission System Operator in Serbia
Regulatory Authorities	
AERS	Energy Agency of the Republic of Serbia
ANRE	National Agency for Energy Regulation of the Republic of Moldova
ERC	Energy, Water Services and Municipal Waste Management Regulatory Commission of Republic of North Macedonia
ERE	Energy Regulatory Authority of Albania
ERO	Energy Regulatory Office of Kosovo*
GNERC	Georgian National Energy and Water Supply Regulatory Commission
NEURC	National Energy and Utilities Regulatory Commission
PSRC	Public Services Regulatory Commission of the Republic of Armenia
REGAGEN	Energy and Water Regulatory Authority of Montenegro
SERC	State Electricity Regulatory Commission of Bosnia and Herzegovina
Power Exchanges	
ALPEX	Albanian Power Exchange
MEPX	Montenegrin Power Exchange
MEMO	National Electricity Market Operator MEMO

SEEPEX A.D.	Serbian Power Exchange
GENEX	Georgian Energy Exchange
NEMO	Nominated electricity market operator
SEE CAO	Coordinated Auction Office in South East Europe

Main findings – Day-ahead markets and cross-zonal capacity allocation

1. Overview of the day-ahead markets in the CPs

In 2023, the day-ahead (DA) markets were operational in Albania, Montenegro, North Macedonia, Serbia, and Ukraine. Albania, North Macedonia and Montenegro launched their DA markets in 2023. Ukraine's power exchange has a four-year history, starting from July 1, 2019, and Serbia has been operating the DA market since February 17, 2016. From February 2024, the DA market is operational in Kosovo*.

In Albania and Kosovo* the Albanian Power Exchange (ALPEX) provides DA trading services. This duty is delegated to Montenegrin Power Exchange Ltd. – (MEPX) in Montenegro. National Electricity Market Operator MEMO Ltd Skopje (MEMO) is responsible for the DA trading services in North Macedonia. Similarly, the Serbian Power Exchange (SEEPEX A.D.) provides DA trading services for the Serbian internal market. The JSC Market Operator provides DA trading services in Ukraine. As for the trading platforms, EPEX SPOT provides this service to MEMO, MEPX and SEEPEX A.D. On the other hand, BSP SouthPool provides clearing services to MEPX and MEMO.

In the DA markets of the listed CPs, the products primarily consist of standard one-hour products. In Montenegro, the standard linear product is available for each hour, which can be submitted as an hourly bid or the profile bid for the base load (from 00:00 to 24:00) and the peak load (from 08:00 to 20:00). For profile products, the energy in each hour must be the same. Block products/bids submission has not been possible thus far. The trade lot used for submitting the order is MW with one decimal digit. In North Macedonia, only the standard DA product, with a time granularity of one hour, is available. Similar to Montenegro, the trade lot used for submitting the order is MW with one decimal and block products are not available. In Serbia, the product time granularity is one hour, with a minimum bid size of 0.1 MW or 100 kW, and linear or block bids can be submitted. In Ukraine, bidding in the DA market includes hourly orders, block orders, and flexible orders, as outlined in Appendix 4 of the DA/ID market rules. Block orders can be simple, profiled and linked.

DA market is not operational in Bosnia and Herzegovina, Moldova and Georgia[5].

In 2023 DA market in Georgia was operating in a dry-run regime.[6] The DA trading services are provided by the Georgian Energy Exchange (GENEX), which was founded in 2019 and licensed in 2020 by the GNERC. Due to the technical capabilities of the trading platform, there are minimum and maximum technical price limits for each MWh set by the GNERC based on GENEX's proposal. In the DA market, electricity prices are expected to be formed based on the marginal pricing principle for each market time unit. GENEX will utilize the European Market Integration Algorithm EUPHEMIA to set market clearing prices for the internal market, where products will be traded hourly in MWhs.

[5] The DA market in Georgia was launched in July 2024. However, as this report focuses on the state of play as of 2023, these developments will be addressed in the subsequent report.
[6] Resolution of the Government of Georgia №246 on approving the electricity market model concept

Table 1. Day-ahead markets in Energy Community Contracting Parties

Contracting Party	Day-ahead market GOT	Day-ahead market GCT	The minimum or maximum limit to the day-ahead price	Applied pricing principle
Albania	10:00 (CET) D-3	12:00 (CET) D-1	Minimum price: 0 EUR /MWh Maximum Price: 900 EUR /MWh	Pay as Clear principle
Bosnia and Herzegovina	N/A			
Georgia	Four weeks before the GCT. Market participants can amend the submitted bid before the GCT	12:00 (CET) D-1	Minimum price: - 70 EUR /MWh; Maximum price: 350 EUR /MWh	Marginal pricing principle for each market time unit
Kosovo*	10:00 (CET) D-3	12:00 (CET) D-1	Minimum price: 0 EUR/MWh Maximum price: 900 EUR /MWh.	N/A
Moldova	N/A			
Montenegro	45 days before the delivery day	10:15 (CET) D-1	Minimum price: 0 EUR/MWh Maximum price: 2,000 EUR/MWh	Marginal pricing principle Single market price is determined for each market time unit
North Macedonia	45 days before the GCT	10:35 (CET) D-1	Minimum price: 0,0016 EUR/MWh or 0,1 MKD/MWh Maximum price: 813 EUR/MWh or 50000 MKD/MWh	Marginal pricing principle. Sigle market price is determed for each market time unit Uniform pricing in accordance with the European market model (EUPHEMIA)
Serbia	45 days before the GCT	11.00 (CET) D-1	Minimum price: 0 EUR/MWh because there is no negative price; Maximum price: 4.000 EUR/MWh in line with the EU	Marginal pricing principle
Ukraine	00:00 D – 7	12:00 (EEST in the summer and EET in the winter) D – 1	Minimum price: 10.00 UAH (0.25 EUR)/MWh; Maximum price: 00.00-07:00, 23:00-24:00: 3,000.00 UAH (77EUR)/MWh; 07:00 – 08:00, 11:00-17:00: 5 600.00 UAH (143 EUR)/MWh; 08:00-11:00: 6900 UAH (176 EUR)/MWh	Marginal pricing principle

			17:00 – 23:00: 7 500UAH (192 EUR)/MWh	

According to article 47(2) of the EnC CACM Regulation, the DA market gate closure time in each bidding zone shall be noon market time DA. However, this regulation allows setting a different gate closure time until they have joined SDAC. Currently, none NEMO of CPs has joined SDAC. As illustrated in Table 1, some CPs have introduced GCT harmonized with SDAC (AL, XK* GE and UA), while the others opted for earlier GCT (ME, MK and RS). The GOT varies from 45 days before the delivery day or GCT (ME, MK and RS), to three days before the delivery day (AL, XK*).

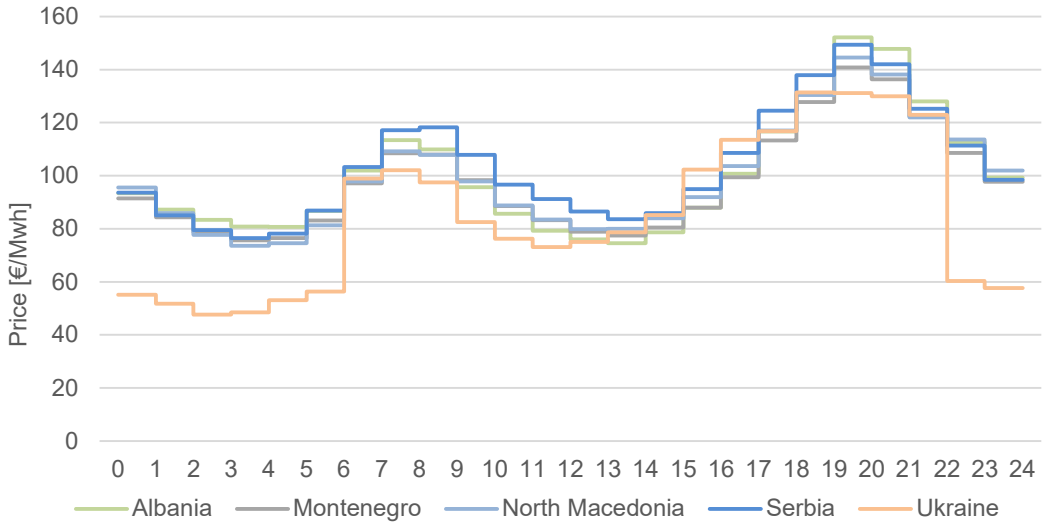
All six CPs operating the DA market, have introduced minimum and maximum limits to the wholesale price and apply the marginal pricing principle to determine the final price. In Ukraine, the minimum and maximum price limits are set by the NEURC.[7] As indicated in Table 1, Ukraine implements varying maximum price limits for different timeframes within a day. Even though the maximum and minimum price limits were mostly introduced to protect market participants, in line with EnC Electricity Regulation, there shall be no such price limits, except for harmonized technical bidding limits that shall be sufficiently high so as not to unnecessarily restrict trade.

1.1 Average prices and volumes traded on DA markets

In 2023, the average annual DA prices in EnC CPs were around 100 EUR/MWh in Albania, 98 EUR/MWh in Montenegro, 99 EUR/MWh in North Macedonia, 103 EUR/MWh in Serbia and 91.5 EUR/MWh in Ukraine. Considering the level of average prices in the Western Balkans, a certain degree of price correlation between the markets of these countries can be observed.

The following Figure shows the average[8] DA prices in 2023 in EnC for each hour of the day.

Figure 1 Average day-ahead hourly prices in 2023[9]



The daily profiles of average prices follow a similar shape in the Western Balkans' DA markets, with two

[7] NEURC Resolution № 1126 27.06.2023
[8] Calculated as a mean value.
[9] Source: ENTSO-E Transparency Platform

local peaks around 8 a.m. and 8 p.m. The hourly average prices in these markets are also comparable: for example, during the peak hour (7 p.m. - 8 p.m.), average prices range from 140.92 €/MWh in Montenegro to 152.24 €/MWh in Albania. On the other hand, the average hourly prices in 2023 in Ukraine are lower than in other CPs during the off-peak hours, due to, inter alia, application of low price caps, as indicated in Table 1.

In order to observe the change of DA prices during the year as well as their trends compared to EU MS, the Figure 2 shows average daily prices in the DA markets of Western Balkans' CPs and the neighbouring EU MSs (Bulgaria, Croatia, Greece, Hungary, Italy and Romania), while Figure 3 shows average daily prices in Ukraine and the neighbouring EU MSs (Hungary, Poland, Romania and Slovakia). In general, average prices in Western Balkans DA markets follow to a certain extent DA prices in neighbouring MSs (e.g., average prices in SEEPEX are close to prices in HUPX).

Figure 2 Average daily DA prices in 2023 – *Western Balkans and the neighbouring MSs*[10]

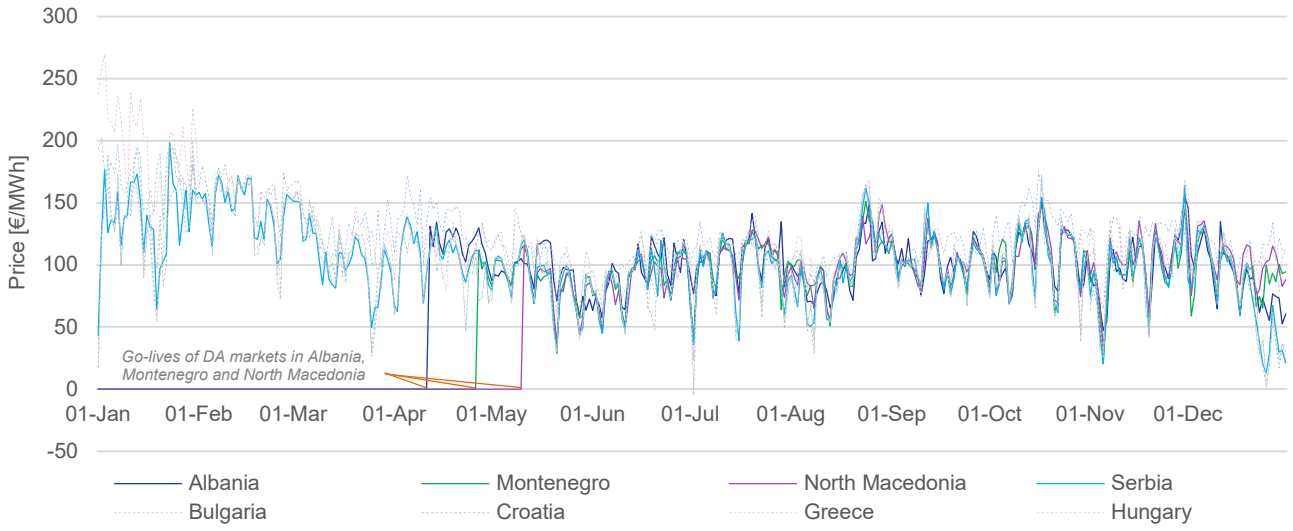
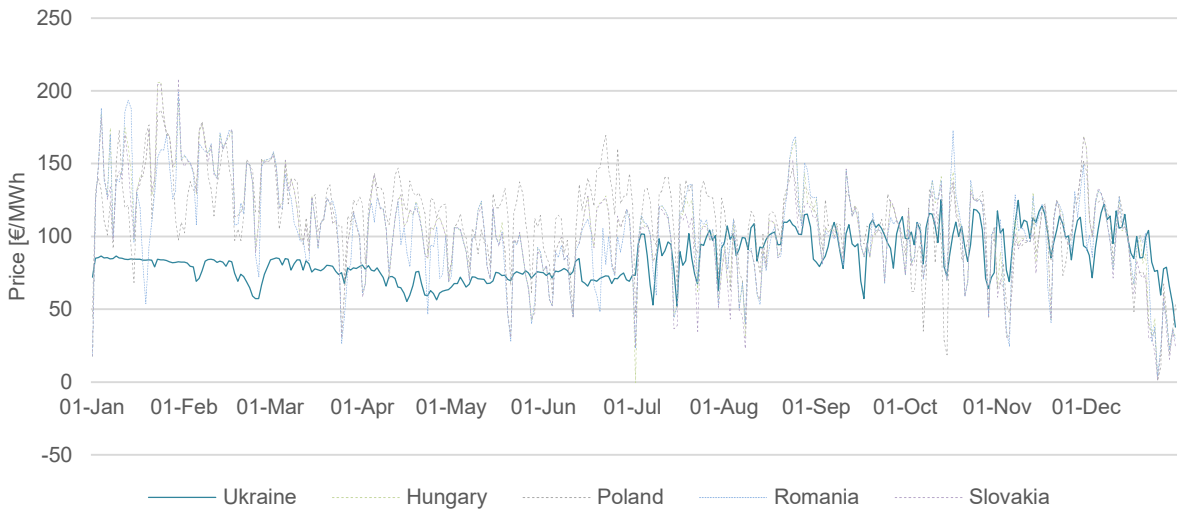


Figure 3 Average daily DA prices in 2023 – *Ukraine and the neighbouring MSs*[10]



On the other hand, for the first half of 2023, average prices in Ukraine were lower than in neighbouring

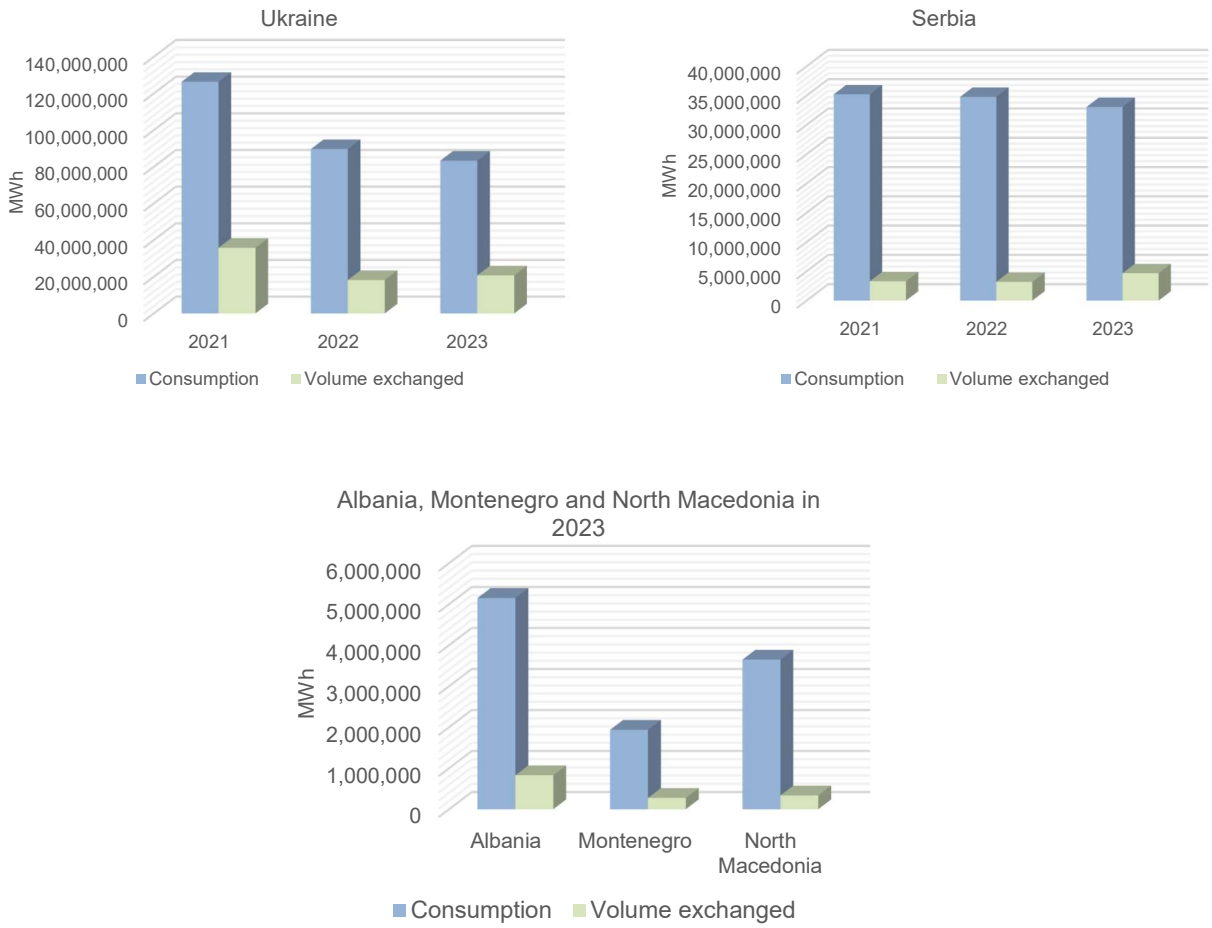
[10] Source: ENTSO-E Transparency Platform

MSs, while towards the end of 2023 they were reaching levels comparable to neighbouring MSs. Nevertheless, higher price convergence of all CPs' DA markets with EU is expected after the implementation of market coupling, i.e., after joining SDAC.

Figure 4 shows the comparison of the volumes exchanged in DA markets and total consumption in Albania, Montenegro, North Macedonia, Serbia and Ukraine. Since DA markets in Serbia and Ukraine have a several-year history, the data is shown for 2021, 2022 and 2023, while the data for Albania, Montenegro and North Macedonia refer to 2023 (from the date these markets went live till the end of December 2023).

In Ukraine, the volumes exchanged on the DA market vary from 28% of total consumption in 2021 to 24.9% in 2023. However, the DA market share (20,750 thousand MWh) in 2023 was only 12.5% of total market volume (158,930 thousand MWh). In Serbia, the volumes traded corresponded to around 9.3% of total consumption in 2021 and 2022, while the ratio increased to 14.16% in 2023. In Albania, Montenegro, volumes exchanged on the DA market by the end of 2023 were around 16.07% and 14.21% of total consumption, respectively, while in North Macedonia this ratio is a bit lower – around 9.19%.

Figure 4 Volumes exchanged on the DA market and consumption



2. Day-ahead cross-zonal capacity allocation in the CPs

The DA cross-zonal capacity allocation is possible on the borders of most CPs, including borders with EU Member States (Annex I provides the interconnection data for 2023 & 2022)[11]. The DA cross-zonal capacity allocation is not possible in Georgia. Currently, Georgia is not electrically connected with any other CPs or EU Member States.

As illustrated in Table 2, the Coordinated Auction Office in South East Europe (SEE CAO) primarily conducts auctions between CPs and Member States. Additionally, this function is also fulfilled by the Joint Allocation Office (JAO) for the allocation of daily cross-zonal capacity on borders between Serbia and Bulgaria, Serbia and Croatia, Ukraine and Poland, Ukraine and Slovakia and Ukraine Hungary. Furthermore, on some borders, the allocation of daily cross-zonal capacity is also carried out by the transmission system operators (TSOs) of relevant CPs or Member States. From February 2024, implicit capacity allocation is performed on the bidding zone border between Albania and Kosovo*.

Table 2. *The entities responsible for performing DA cross-zonal capacity allocation*

SEE CAO	Montenegrin TSO	TSO of Bulgaria	TSO of Serbia	JAO	TSO of Bosnia and Herzegovina	TSO of Ukraine
BA – ME BA – HR MK – XK* ME – XK* ME – AL ME – IT MK – GR AL – GR	ME – RS	BG – MK	RS – MK RS – HU RS – RO	RS – BG RS – HR UA – PL UA – SK UA – HU	RS – BA	UA – RO UA –MD

In all CPs, where the daily capacity allocation is possible (as indicated in Table 4), the allocation process occurs via auction utilizing a web-based allocation tool, with hourly products being offered (as indicated in Table 3). In Bosnia and Herzegovina, daily Available Transmission Capacity (ATC) is offered in units of 1 MW, with a minimum of 1 MW. In Montenegro, bid quantities must be expressed with zero decimals, and the minimum bid size is 1 MW per hour. For the auctions conducted by SEE CAO, the minimum price is set at 0 €/MWh per hour, while for the auctions performed by the TSO of Montenegro, the minimum price is set at 0.01 €/MW per hour.

[11] The Ukraine DA cross-zonal allocation rules are primarily based on the provisions of the Harmonised Allocation Rules.

Table 3. Day-ahead cross-zonal capacity allocation mechanisms

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
Web-based allocation tool	✓	✓	*N/A*	✓	✓	✓	✓	✓	✓
Allocation via auction	✓	✓	*N/A*	✓	✓	✓	✓	✓	✓
Hourly product	✓	✓	*N/A*	✓	✓	✓	✓	✓	✓
Marginal pricing principle	✓	✓	*N/A*	✓	✓	✓	✓	✓	✓
Collateral for participation in capacity allocation	✓	✓	*N/A*	✓	-	✓	-	-	✓

The marginal pricing principle is applied for price formation in all CPs for daily cross-zonal capacity allocation. In Montenegro, the marginal pricing principle is applied for both auctions performed by SEE CAO and Montenegrin TSO. All received bids are sorted in descending order with regard to the bid price. If the total quantity for which valid bids are submitted is lower than or equal to the offered capacity, then the marginal price is zero. If the total quantity for which valid bids are submitted is higher than the offered capacity, the marginal price is set at the lowest bid price accepted (in part or full). A similar approach is used in Ukraine to determine the marginal price, at each bidding zone and direction.

Albania, Bosnia and Herzegovina, Kosovo* and Montenegro require collateral for participation in a DA capacity allocation auction. In Bosnia and Herzegovina, as well as in Albania, Kosovo*, Montenegro and North Macedonia for the auctions performed by SEE CAO and Ukraine, a bank guarantee or a cash deposit has to be disbursed in a dedicated Business Account. For the auctions performed by Montenegrin TSO and Serbian TSO, there is no collateral requirement for participation in the auctions, however, one of the preconditions for participation in the auction is a conclusion of a contract for balance responsibility with the TSOs of Montenegro and Serbia. In Moldova collateral for participation in capacity allocation is not defined. However, market participants must provide collateral for participation in annual and monthly allocation auctions on the Moldova-Romanian border. Additionally, collateral is mandatory for annual, monthly, and daily allocation on the Moldova-Ukraine border. It is important to note that, at this moment the allocation is implemented on the Moldova-Romanian border on a daily basis, as for the Moldova – Ukraine border, the monthly allocation is supposed to commence in March 2024.

Nomination of the allocated cross-zonal capacity is mandatory in Bosnia and Herzegovina and Serbia. In Kosovo*, the nomination is mandatory if the allocated capacity is used. Allocated cross-zonal capacity nomination is not compulsory in Albania, Montenegro, North Macedonia and Ukraine. However, in North Macedonia, the payment is mandatory.

For the purpose of avoiding DA capacity hoarding, Montenegro, Bosnia and Herzegovina and Ukraine apply the Use-It-or-Lose-It (UIOLI) principle. In Montenegro, in case the transmission rights allocated in the daily auction are not nominated, they will be offered in intraday auctions (only for the borders with other CPs), and the transmission rights holder is not subject to financial compensation.

Table 4. Day-ahead cross-zonal capacity allocation

Contracting Party	Day-ahead capacity allocation with other CPs/MSs	Deadline for submission of the schedules to the TSO	Day-ahead cross-zonal GCT
Albania	Kosovo*; Montenegro; Greece	14:00 (CET) D-1	9:30 (CET) D-1
Bosnia and Herzegovina	Montenegro; Croatia; Serbia	8:00 (CET) D-1 - long-term[12] cross-border transmission rights 14:30 (CET) D-1 – daily cross-border transmission rights	14:30 (CET) D-1
Georgia	N/A		
Kosovo*	Albania; Montenegro; North Macedonia[13]	14:00 (CET) D-1 – Albania, North Macedonia 14:30 (CET) D-1 – Montenegro	N/A
Moldova	Romania;	H-1 D	N/A
Montenegro	Albania; Bosnia and Herzegovina; Serbia; Kosovo*; Italy	14:30 (CET) D-1 15.00 (CET) D -1 - possibility of amending submitted schedules	09:30 (CET) D-1 (all CPs) 10:00 (CET) D-1 – Italy[14]
North Macedonia	Greece; Bulgaria Serbia; Kosovo*	14:29:59 (CET) D-1	For long-term nominations: 08:00 (CET) D-1 For short-term nominations: 14:00 (CET) D-1 between Kosovo* and Greece, 14:30 (CET) D-1 between Bulgaria and Serbia.
Serbia	Bosnia and Herzegovina; Montenegro; North Macedonia; Hungary; Romania; Bulgaria; Croatia	15:30 (CET) D-1	15:30 (CET) D-1
Ukraine	Romania; Moldova; Poland; Slovakia; Hungary	14:30 (EEST in the summer and EET in the winter) D-1; 2 hours after GCT in the case of rescheduled trade in DA market.	UA-RO: D – 1 UA-MD: D – 2 UA-PL: D – 2 UA-SK: D – 2 UA-HU: D -1

According to Table 4, most CPs have aligned deadlines for the submission of schedules to the TSO.

[12] Annual and monthly cross-border transmission capacity

[13] Transmission capacity is not allocated between EMS and KOSTT bidding zones, and that case has been referred by KOSTT to the Energy Community Secretariat https://www.energy-community.org/legal/cases/2021/case0221RS.html

[14] The time provided is applied in case of regular operating conditions

Main Findings – Intraday markets and cross-zonal capacity allocation

3. Overview of the intraday markets in CPs

Intraday (ID) markets are currently operational only in Serbia and Ukraine, starting from July 2023 and 2019, respectively. In both countries, ID trading services are provided by the same operator that offers DA services: SEEPEX in Serbia and the JSC Market Operator in Ukraine. In Serbia, market operations are facilitated by the BSP-M7 System. Both markets employ a continuous trading approach with a time granularity of one hour. Market participants in Serbia can submit linear or block bids, while in Ukraine, according to Appendix 4 of the DA/ID Market Rules, bidding in the ID market includes hourly and block orders. Block orders in Ukraine can be standard (peak, base, off-peak) and non-standard. Both countries have implemented minimum and maximum limits to the ID wholesale prices (as indicated in Table 5).

The establishment of the spot market has not yet been introduced in the national legislation of Bosnia and Herzegovina. Additionally, the ID market is not operational in Georgia, Kosovo*, Moldova, Montenegro, and North Macedonia. However, in 2023, Georgia was operating the ID market in a dry-run regime. In 2020, GENEX obtained the ID market operation license and provides trading services for ID and DA trading. According the legal framework, trading shall occur continuously throughout each calendar day. Standard hourly bids (where the limited price is specified and can be partially satisfied), block bids (placed in more than one consecutive hour and can only be fully satisfied), and Iceberg products (where the application is placed in the auction system in parts, with each subsequent part activated after the previous part is fully satisfied) can be traded in the market.

Table 5. Intraday markets in the Energy Community Contracting Parties

Contracting Party	Intraday market GOT	Intraday market GCT	The minimum or maximum limit to the ID wholesale price
Albania	N/A		
Bosnia and Herzegovina	N/A		
Georgia	13:00 (CET) D-1	H-1	Minimum technical margin for electricity price – 70 (minus seventy) EUR /MWh; Maximum technical margin for electricity price – 350 EUR /MWh;
Kosovo*	N/A		
Moldova	N/A		
Montenegro	N/A		
North Macedonia	N/A		
Serbia	18:00 (CET) D-1	H-1	Minimum price: 0 EUR/MWh Maximum price: 9.999,99 EUR/MWh

Ukraine	15:00 (EEST in the summer and EET in the winter) D – 1	H-1	**Same as the DA price** 00.00-07:00, 23:00-24:00: 3,000.00 UAH (77EUR)/MWh; 07:00 – 08:00, 11:00-17:00: 5,600.00 UAH (143 EUR)/MWh; 08:00-11:00: 6,900 UAH (176 EUR)MWh; 17:00 – 23:00: 7500.00 UAH (192 EUR)/MWh

4. Intraday cross-zonal capacity allocation in CPs

ID cross-zonal capacity allocation with neighbouring CPs and EU member states is possible in Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia and Serbia (information on interconnection data for 2023 & 2022 is provided in Annex I). Unlike DA cross-zonal capacity allocation (as indicated in Table 2), ID cross-zonal capacity allocation is performed by the TSOs of the relevant CPs or Member States (illustrated in Table 6).

Table 6. *The entities responsible for performing ID cross-zonal capacity allocation*

Montenegrin TSO	TSO of Romania	TSO of Serbia	TSO of Kosovo*	TSO of Bosnia and Herzegovina
ME – RS ME – XK* ME – AL	RO – RS	RS – MK RS – HU RS – BG RS – HR	XK* – AL XK* – MK	BA – ME BA – HR BA – RS

All respective CPs allocate ID cross-zonal capacity via a web-based platform. The allocation is continuous in the majority of the CPs (as illustrated in Table 7) and is based on the “First come –First serve” principle. In Bosnia and Herzegovina and Montenegro, the ID ATC is allocated by the Transmission Capacity Allocator. The Capacity Holder does not pay any price for the reservation or use of the allocated ID capacity. ID ATC is offered in units of 1MW with a minimum of 1MW. In all respective CPs, ATCs are offered as hourly products.

One of the preconditions for participation in ID cross-zonal capacity allocation in Albania, Bosnia and Herzegovina, Montenegro and Serbia is to conclude the balance responsibility contract with respective TSOs. Moreover, in Albania, even other market participants, registered in one of the CPs can participate in ID cross-zonal capacity allocation. Since the capacity is not priced, collateral for participation is not defined in any of the CPs that perform ID allocation (illustrated in Table 7).

Table 7. ID cross-zonal capacity allocation mechanism

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
Web based allocation tool	✓	✓		✓		✓	✓	✓	
Continuous allocation	✓	-		-		✓	✓	✓	
Hourly product	✓	✓		✓		✓	✓	✓	
First come first served principle	✓	✓		✓		✓	✓	✓	
Collateral for participation in capacity allocation	-	-		-		-	-	-	

The ID cross-border capacity allocated by ISO BIH should be reserved 60 minutes before the start of a scheduled exchange at the latest. After that dadline, allocated transmission capacity is taken. In Kosovo*, nomination of the ID cross-zonal capacity is mandatory if it is used. In Montenegro, Serbia and North Macedonia, the transmission right holder is obliged to nominate allocated cross-zonal capacity. Additionally, in Montenegro and North Macedonia, the right holder must utilize the full amount of the allocated transmission right. Contrary to other CPs, in Albania, the nomination of the allocated cross-zonal capacity is not mandatory.

To prevent capacity hoarding for Montenegro – Albania, Montenegro – Bosnia and Herzegovina and Montenegro – Kosovo* ID capacity allocation, the Montenegrin TSOs have the authority to exclude a participant from the ID capacity allocation process for the period of twelve months if the transmission right holder breaches the nomination obligation three times within a year. The same mechanism applies to the Montenegro – Serbia border; however, participation in the ID capacity allocation process is prohibited for three months.

In Bosnia and Herzegovina, the capacity holders and their cross-border partners (hereinafter referred to as the Counterparts) are obliged to utilize the entire amount of ID capacity right; otherwise, the right holders lose it, as discussed above. In this scenario, the nominated amount of capacity has to be equal to the ID capacity right obtained during the ID process for each hour and direction and it is fully matched with the Counterpart nomination. This obligation is monitored by the Transmission Capacity Allocator. Albania, Kosovo*, North Macedonia and Serbia do not have mechanisms to mitigate ID capacity hoarding.

Table 8. Intraday cross-zonal capacity allocation

Contracting Party	Intraday capacity allocation with other CPs/MSs	Deadline for submission of the generation/consumption/exchange schedules to the TSO	Intraday cross-zonal GCT
Albania	Kosovo*; Montenegro;	60 minutes before the delivery hour	H-90 minutes
Bosnia and Herzegovina	Montenegro; Croatia; Serbia	Nomination of a daily schedule in ID period (D) may be done from 6:00 p.m. in a day ''D-1'' until ''H-0h45min'' in a day ''D'', where ''H'' is an hour when the planned exchange is starting. With each nomination affected by a change in the cross-border plan, it is necessary to ensure cross-border transmission	ID Allocation Request GCT – H-60min Nomination GCT – H-45min Matching GCT – H-30min

		capacities. ID cross-border capacity allocated by ISO BIH should be reserved 60 minutes before the start of a scheduled exchange at the latest since, after that deadline, allocated transmission capacities are taken. The nomination of ID cross-border exchange plans may be done up to 45 minutes before the beginning of an hour for which cross-border exchange is planned. The nomination of generation plans and forecast, internal exchange and exchange plans to cover losses may be done up to 5 minutes before the beginning of the hour for which the exchange is planned.	
Georgia	N/A		
Kosovo*	Albania; Montenegro; North Macedonia	For generation and consumption: H-1 minute For exchange schedules: H-1	H-90 minutes
Moldova	-	According to the WEMR, the final physical notifications should be presented to the TSO by the balance responsible parties (BRPs) one hour before the time of electricity delivery. This notification is used by TSO when calculating the BRP imbalance.	-
Montenegro	Albania; Bosnia and Herzegovina; Serbia; Kosovo*.	H-30 minutes	H-90 minutes for ME-AL and ME-XK* H-1 for ME-RS and ME-BA
North Macedonia	Serbia; Kosovo*	18:00 on day D-1 to 23:00 on day D, submission of schedules with Intra Day nominations	H-1
Serbia	Bosnia and Herzegovina; Montenegro; North Macedonia; Hungary; Romania; Bulgaria; Croatia	Starting from 18:00 (CET) on the day D-1 but not later than 60 minutes before the start of the first hour to which the ID Cross-zonal Transaction relates.	H-1
Ukraine	N/A		

In most CPs, ID cross-zonal GCT is one hour before the start of the relevant ID market unit (as indicated in Table 8), while in others, it is 90 minutes before. However, pursuant to the EnC CACM Regulation, after joining SIDC, TSOs and NEMOs will have to apply ID cross-zonal GCT as set in accordance with Article 59(1) of Regulation (EU) 2015/1222. According to the latest ACER decision[15], ID cross-zonal GCT is set to one hour before the start of the relevant ID market unit[16].

[15] ACER, DECISION OF THE AGENCY FOR THE COOPERATION OF ENERGY REGULATORS No 04/2018, Annex I https://www.acer.europa.eu/documents/search?search_api_fulltext=gate+closure+time

[16] Except for the Estonia-Finland border where ID cross-zonal GCT is 30 minutes before the start of the relevant ID market unit.

Main findings – progress towards market coupling

5. NEMO designation and the establishment of Local Implementation Projects

To perform the single DA and/or ID coupling, the EnC CACM Regulation stipulates an obligatory requirement for each CP electrically connected to a bidding zone of another CP or a Member State to ensure that one or more nominated electricity market operators (NEMOs) are designated by six months after the entry into force of the Regulation.

Currently, NEMOs for DA and ID markets are designated in Albania, Kosovo*, North Macedonia and Serbia. ALPEX is designated as NEMO in the bidding zone of Albania and Kosovo*.

On September 9th, 2020, the Government of North Macedonia, in accordance with the Energy Law and the "*Regulation on the operation of the Organized Electricity Market Operator and the necessary technical, personnel and financial conditions to be met*", designated MEMO as the NEMO. This decision was made following a previous ERC proposal and positive opinion of the Macedonian TSO. As per the Energy Law, MEMO is tasked with establishing and managing the organized market (Power Exchange) and is responsible for market coupling.

In Serbia, SEEPEX A.D is performing the roles of the NEMO. In Moldova, Montenegro and Ukraine, NEMOs have not yet been designated. Despite this, in Moldova and Montenegro, the legal monopoly model is applied, as stated by the relevant legislation. In addition, under the Electricity Law, the designation of NEMOs shall be made through a Government Decision.

Parallel to the NEMO designation process, there are several market coupling projects involving the CPs. In 2018, a regional market coupling project between Albania, Italy, Montenegro and Serbia – AIMS was established with the support of the Energy Community Secretariat. However, there have been no new developments regarding this project.

On 31 January 2024, the Albanian Power Exchange (ALPEX) conducted its first DA auction for electricity delivery in Kosovo*, which is the first market coupling project that went live in the Energy Community CPs. Having this in mind, the cross-zonal capacity between Albania and Kosovo* is allocated implicitly.

Recently, with the support of USAID and NARUC, the Memorandum of Understanding (MoU) on SEE Electricity DA Market Coupling was signed between the NRAs, TSOs and PXs from Greece, Albania, North Macedonia and Kosovo*. Additionally, an ongoing market coupling initiative exists between North Macedonia and Bulgaria, facilitated by a separate MoU between Market Operators and TSOs. The Memorandum signatories defined the main project stages, implementation roadmap, and structure and composition of project working groups. Due to the regulatory framework harmonization process between the CPs and the EU, the project is currently on hold, necessitating an adjustment to the project roadmap. In addition to these market coupling initiatives, Montenegro and Italy are working on establishing a local implementation project between the countries.

Main findings – Balancing market

6. Overview of balancing markets in CPs

As a general observation, almost all CPs have in place balancing mechanisms and the associated rules on how TSOs shall balance the system[17]. In most CPs, procurement of balancing services is done through a market-based mechanism, i.e. transparent auction or tender where the best commercial/technical offers are accepted (see Table 9). The EnC EBGL Regulation and EnC Electricity Regulation also require market-based procurement of balancing capacity and balancing energy, whereas the latter stipulates that the settlement of balancing energy should be based on marginal pricing (pay-as-cleared) unless all regulatory authorities approve an alternative pricing method.

Table 9. *Provision of balancing services*

Contracting Party	Is procurement of balancing services done via market-based procedures?	When are the contracts for balancing capacity concluded?	Prices for balancing services – for capacity?	Prices for balancing services – for activation of balancing energy?
Albania	Market-Based	3 days before the first day of the contracted period starts. The contracting period is 1 week, on an hourly basis.	Pay-as-bid: The balancing service providers (BSPs) are paid according to their bid price for the contracted amount resulting from the process.	The marginal price principle applies to activated orders from the merit order list.
Bosnia and Herzegovina	Yes. Market-based process.	Yearly auctions (monthly resolution) at the beginning of December Y-1 for year Y. If necessary monthly auctions at the beginning of M-1 for month M.	Prices for capacity products are set based on offers from BSPs using Pay-as-Bid principle. (see Annex II, Case Study 1)	The price for balancing energy is established according to the Pay-as-Bid principle (see Annex II, Case Study 1).
Georgia	Yes, for balancing products for FCR[18] and FRR[19].	The tender for the procurement of the balancing capacity is announced each week. The gate for bids opens every Monday at 07:30 CET, a week before the product delivery week, and closes on Thursday, 15:00 CET of the same week. The most common contracting period is one week.	Prices for balancing capacity are determined based on BSP offers.	Prices for balancing energy are determined based on BSP bids. According to the balancing market rules, GNERC has set a maximum cap of 384 EUR/MWh and a minimum cap of -0 (zero) EUR/MWh.

[17] Georgia and Kosovo* have not yet implemented organized balancing market. Information provided in this section regarding Georgia is based on the Wholesale Market rules approved by GNERC.
[18] In the transitional period, by the end of the year 2024, the Frequency Containment Reserve (FCR) will not be allocated based on tender. In the event that the TSO makes a request, the FCR qualified electricity producer with PSOs will be obligated to provide services.
[19] For the supply of the Frequency Restoration Reserve, in the balancing capacity tender, applications shall be submitted with zero price.

Contracting Party	Is procurement of balancing services done via market-based procedures?	When are the contracts for balancing capacity concluded?	Prices for balancing services – for capacity?	Prices for balancing services – for activation of balancing energy?
Kosovo*	Yes, for manual Frequency Restoration Reserve (mFRR), while procurement of automatic Frequency Restoration Reserve (aFRR) is based on long-term contracts.	aFRR is a long-term contract mFRR is a yearly contract	The price for balancing capacity from aFRR is based on the Albanian balancing Market, while theprice for balancing capacity from mFRR is based on winning contract(s).	The price for activating balancing energy from aFRR is based on the Albanian Balancing Market, while the price for activating balancing energy from mFRR is determined by monthly coefficients referencing the Hungarian Power Exchange price..
Moldova	According to the WEMR, the balancing services [20]are procured by the TSO using a market-based approach.	N/A	The price for balancing capacity is established according to the pay-as-bid principle, with the TSO selecting the lowest quantity-price pairs offered by the balancing market participants.	The price for balancing energy is established according to the pay-as-bid principle, with TSO selecting the lowest pairs of quantity-price offers provided by the balancing market participants.
Montenegro	Market-based However, the price of balancing capacity is set in advance, while the price of balancing energy is not regulated, but caps are defined.	Usually, the contracts are concluded in December for the following year. The contracting period is usually one year.	Determined according to the Methodology for setting prices, terms and conditions for providing ancillary and balancing services and set in advance by the REGAGEN	The balancing energy price is set in a transparent process. However, the bid price cannot be higher than the caps prescribed by the above-mentioned methodology adopted by REGAGEN. It has to be noted that the caps are not fixed, but they refer to the DA price on HUPXhi.
North Macedonia	Yes, balancing services are procured through a market-based mechanism.	One moth in advance for balancing capacity.	The price for balancing capacity is established via pay as bid principle with merit list. There are no caps for balancing capacity.	The price is set on the market base with predefined caps.
Serbia	Market-based for balancing energy, regulated for balancing reserve	One month before. It is concluded for a calendar year.	Regulated price based on NRA's decision.	Based on bids from BSPs.

[20] At the moment there are no national BSP that are offering balancing services to TSO, the grid is being balanced by means of FSkar mechanism.

Contracting Party	Is procurement of balancing services done via market-based procedures?	When are the contracts for balancing capacity concluded?	Prices for balancing services – for capacity?	Prices for balancing services – for activation of balancing energy?
Ukraine	Yes. The balancing services are procured via the balancing market and the ancillary services market.[21]	Most usually, 1 day ahead	The price for ancillary services is determined based on the results of the ancillary services auctions or is formed by the TSO in accordance with the algorithm defined in the methodology.[22]	The price is calculated as the weighted average, taking into account marginal upward and downward prices as well as activated balancing energy (more details in the Case Study: Balancing Mechanism in Ukraine)

Some CPs apply annual contracts for balancing capacity procurement, while others opt for shorter contracting periods. It has to be noted that after the transposition of the EnC Electricity Regulation, the contracts for balancing capacity shall not be concluded more than one day before the provision of the balancing capacity and the contracting period shall be no longer than one day, unless and to the extent that the regulatory authority has approved the earlier contracting or longer contracting periods to ensure the security of supply or to improve economic efficiency. However, even if the derogation is granted, some part of balancing capacity products will still have to meet the initial criteria.

In the majority of CPs, any market participant meeting the technical criteria and passing the prequalification test can become a BSP. In Montenegro, BSPs can be a) producers connected to the transmission system that have technical capabilities to provide balancing services; b) consumers that have technical capabilities to provide balancing services (only for tertiary reserve); c) neighbouring TSOs or producers from other scheduling areas – in case the required reserve capacity cannot be provided from BSPs in Montenegro (based on operational agreements with other TSOs and imbalance netting). In North Macedonia, demand response and generation are eligible for providing balancing services. However, energy storage still needs to be incorporated in the regulatory framework. Currently, providing balancing services within Kosovo's* Control Area is not technically feasible. Moreover, the Market Rules lack provisions for aggregation, but ongoing secondary legislation drafting aims to address aggregation, demand response, energy storage, and related mechanisms.

On the one hand, Ukraine has no specific requirements and eligibility criteria for providing balancing electricity in the balancing electricity market, and all market participants are obliged to participate in the market, except RES owning generating units of type B, C and D (according to Transmission Code). On the other hand, only the market participants, meeting the following criteria, can provide balancing capacity services in the ancillary services market:

a. Generating units that have passed the inspection, conducted tests of electrical installations in

[21] Services are provided/purchased on a competitive basis through auction platforms, where the best commercial/technical proposals are accepted.
[22] The rate of payment for the readiness to provide ancillary services based on the results of the ancillary services auction must be equal to the bid price for each settlement period and for each accepted offer received at the ancillary services auction. Detailed information can be found Methodology of price settlement for auxiliary services, by NEURC Resolution No. 635 of April 26, 2019.

accordance with the Transmission Code, with a total installed capacity of at least 1 MW at the point of connection;

b. Demand facilities that have passed an energy audit, conducted electrical installation tests in accordance with the Transmission Code, with a total regulating power at the connection point of at least 1 MW;

c. Energy storage units that have passed the inspection and tested electrical installations in accordance with the Transmission Code, with a total regulating power at the connection point of at least 1 MW.

Table 10. *BSP prequalification, procurement of balancing capacity and pre-determined price for balancing energy*

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
Prequalification process for BSPs	✓	✓	✓	-	✓	-	✓	✓	✓
Separate procurement for upward and downward balancing capacity	✓	✓	✓	✓	✓	-	✓/-	-	✓
Pre-determined price for balancing energy in the contract for balancing capacity	-	-		✓		-	-	-	-

Almost all CPs have a prequalification process that allows certain market participants to qualify for submitting bids for balancing energy or balancing capacity (indicated in Table 10). The prequalification process is described in the Network Codes or Balancing rules approved by the NRA, or it can be drawn up and published by the relevant TSO (Detailed BSP prequalification process in North Macedonia is provided in Annex II, Case Study 5). In Albania, the minimum capacity required to apply for prequalification is at least 3MW. The prequalification process does not exist in Kosovo* and Montenegro. However, in Montenegro, BSPs must have the technical capabilities defined in the contract with the TSO to provide balancing services. The technical capabilities of a BSP are specified in the template contract for balancing service provision, which is prepared by the TSO and approved by REGAGEN.

Procurement of upward balancing capacity and downward balancing capacity is conducted separately for each direction in most CPs, as required by EnC Electricity and EBGL Regulations, except in Montenegro, North Macedonia, and Serbia (illustrated in Table 10). In Montenegro, upward and downward balancing capacity is procured through a single process for both directions. Consumers can provide only upward balancing capacity. In North Macedonia, TSO conducts auctions to purchase aFRR and mFRR balancing capacity in accordance with the aFRR Procurement Rules from the balancing units. Both balancing capacities are procured through one process for upward and downward capacity; however, it is possible to bid for mFRR separately for upward and downward capacity. In Serbia, procurement is conducted in a regulated manner for both directions.

Table 11. Mandatory requirement for certain market participants to offer balancing services

Contracting Party	Is there a mandatory requirement for certain market participants to offer balancing services (if market-based procurement is applied) or to become BSPs (in case of a regulated approach)?
Albania	The minimum capacity required is at least 3 MW for all types of market participants, along with successfully passing the prequalification process for each product they are interested in offering.
Bosnia and Herzegovina	Yes, generators—traditional suppliers of auxiliary services—are obliged to offer ancillary services to ISO BIH
Kosovo*	No, balancing services are offered according to the contract.
Georgia	In general, no. However, during the transitional period, until the end of 2024, if the TSO makes a request, FCR-qualified electricity producers with PSOs will be obligated to provide services.
Moldova	Yes, participation in the BM is mandatory for all qualified generation units and dispatchable consumers. Nonetheless, the TSO can establish mandatory participation without qualification in the process of providing replacement reserves.
Montenegro	Yes, all producers and consumers technically capable of providing balancing services are obliged to offer these services to the TSO through a transparent procedure. The quantity to be offered is not predefined; instead, the TSO will specify the needed balancing capacity, and all aforementioned users must submit offers to the TSO.
North Macedonia	The technical characteristics of the FCR and and the operational requirements for producers participating in the FCR are defined in the Grid Code. As defined in the Grid Code, all hydro and thermal generation units must be equipped with turbine regulators for automatic speed regulation, capable of securing energy for primary regulation. The TSO can release or exempt individual generation unit from the obligation to secure FCR based on generator technology and primary fuel type. All hydro generation units with an installed capacity greater than 10 MW and all thermal generation units with an installed capacity greater than 30 MW must participate in securing FCR. Other hydro and thermal units (those with an installed capacity of less or equal to 10 MW for hydro units and less than or equal to 30 MW for thermal units) are required to activate automatic regulation if required by the TSO.
Serbia	Yes, every balancing entity must provide balancing energy.
Ukraine	Yes, market participants other than RES, who own generating units of types B, C, and D, are obligated to participate in the balancing market. For dispatchable load, the obligation to participate in the balancing market arises if the dispatchable load is selected to provide reserves.

The price for balancing energy is typically not specified or predetermined in the contract for balancing capacity in most CPs, which aligns with the requirements of the EnC Electricity and EBGL Regulations. In Kosovo*, aFRR pricing is based on the Albanian balancing electricity market, while mFRR pricing is determined by a contract referencing specific conditions and the Hungarian Power Exchange price. In Georgia, if the Balancing Service Provider (BSP) bids for the Frequency Restoration Reserve (FRR), it must also provide a price for balancing energy. In Montenegro, even though the price for balancing energy is not predetermined, the offered price cannot exceed the caps prescribed by the Methodology for Setting Prices, Terms, and Conditions for the Provision of Ancillary and Balancing Services to the Transmission System Operator. It is important to noted that these caps are not fixed; they refer to the DA price on the Hungarian Power Exchange.

Additionally, most CPs have mandatory requirements for market participants to offer balancing services if they meet certain technical criteria (as indicated in Table 11). Ukraine also has mandatory requirements for market participants to offer balancing services (capacity) if they meet specific technical criteria (mentioned in points a,b and c above) for generating units B,C and D, except for RES.

7. Imbalance Settlement

In most CPs, all market participants are responsible for the imbalances they cause in the system as indicated in Table 12. Some CPs have exceptions for RES producers or RES producers benefiting from support schemes. Considering the requirements from EnC Electricity Regulation, which has yet to be transposed into EnC CPs, derogations from balance responsibility can only be granted to demonstration projects (subject to regulatory authority approval), power-generating modules with an installed capacity of up to 400 kW (or 200 kW since 2026) and installations benefiting from support under the Energy Community State Aid Rules that were commissioned before 15th of December 2022. In Ukraine, each market participant is required to become a Balancing Responsible Party (BRP) or transfer their financial responsibility for imbalances to another BRP by joining their balancing group based on the conclusion/attachment of the respective agreement. If a market participant transfers their financial responsibility for imbalances to another BRP by joining their balancing group, the imbalance settlement agreement concluded between the TSO and the market participant suspends its effect in terms of financial responsibility for imbalances for the duration of the participation agreement in the balancing group. For electricity producers who have joined the guaranteed buyer's balancing group, the imbalance settlement agreement only suspends its effect for generating units for which a "green" tariff is established or for which the auction winner has acquired support rights.

As seen in Table 12, Bosnia and Herzegovina is the only CP that applies a 15-minute imbalance settlement period (ISP), while other CPs apply an ISP of one hour. In line with the EnC Electricity Regulation, the ISP shall be 15 minutes in all scheduling areas, unless regulatory authorities grant a derogation or an exemption. Most CPs calculate imbalance as the difference between the metered and nominated volumes. The detailed methodology for calculating the imbalance in Georgia, North Macedonia, and Ukraine is provided in Annex II Case Studies 2, 5 and 6. It should be noted that the EnC EBGL Regulation emphasizes harmonization of the main aspects of the imbalance settlement processes, including the principles of calculating imbalances and imbalance prices, by requiring CPs to apply the Methodology for the harmonization of the main features of imbalance settlement, approved by ACER. With this in mind, imbalance settlement mechanisms in some CPs will need to be adapted to meet the requirements of this methodology after the EnC EBGL Regulation is transposed into national legislation.

Table 12. Financial settlement of BRPs

Contracting Party	Balance Responsibility	Imbalance settlement period	Imbalance calculation
Albania	All wholesale market participants must be registered as BRPs and are responsible for the imbalances they cause, according to the Albanian Balancing Market Rules.	1 hour	The BRP imbalance is calculated as a difference between the realized (metered) and scheduled balance for each ISP. a. The realized balance of a BRP is the difference between the total production realized by all generating units and the total consumption realized by all consumers. b. The scheduled balance of a BRP is the difference between the energy sold and purchased within an ISP, taking into account the activation of reserves. The balancing energy volume is subtracted from the total imbalance calculation for that ISP for the concerned BRPs.
Bosnia and Herzegovina	All market participants are balance responsible either as BRPs or as members of the balance group (represented by BRP).	15 minutes	Imbalance means the difference between the measured amount of injected and withdrawn electricity and a shcedule of a BRP or a Market Participant, considering engaged balancing energy.
Georgia	All market participants are responsible for the imbalances they cause, with no exemptions.	1 hour	See Annex II, Case Study 2
Kosovo*	Market participants signing the BRP Agreement are responsible for imbalances. RES producers are responsible for 25% of their absolute imbalances.	1 hour	The difference between the metered and nominated values (adjusted for any activation, if applicable).
Moldova	Yes, according to both the Law and the WEMR, all market participants are financially responsible for their imbalances. One exemption may be prosumers who have installed PV cells and benefit from the net metering mechanism; however, according to the law, this is not a support scheme.	1 hour	Imbalances are calculated as the difference between the net measured position (real metered figure) and the net contracted position (physical notification sent to the TSO) of the BRP.
Montenegro	All market participants are responsible for the imbalances they cause as BRPs or members of the balancing group. However, in the case of RES under the support scheme – feed-in tariff, the Montenegrin Market Operator (COTEE) is responsible for their imbalances.	1 hour	The imbalances are calculated as the difference between the allocated volume of the BPR and its schedule (taking into account adjustment to the schedule in case of activation of balancing energy, if the BRP is also a BSP – imbalance adjustment).

Contracting Party	Balance Responsibility	Imbalance settlement period	Imbalance calculation
North Macedonia	All market participants have balancing responsibilities. RES producers that have obtained preferential status with feed-in tariffs do not have balancing responsibilities. Their balancing responsible party is the Electricity Market Operator.	1 hour	The Electricity Market Operator makes a preliminary imbalance settlement for each balancing group as the difference between the total realized electricity exchange and the announced (nominated) exchange of that balancing group for each ISP.[23]
Serbia	All market participants are financially responsible for the imbalances.	1 hour	Imbalance is calculated based on the nominated imports and exports of the balancing group, as well as the realized production and consumption for all WIPs of that balancing group, offset by engaged balancing energy.
Ukraine	Yes, according to the Regulations, all market participants, except for consumers who purchase electricity under consumer supply agreements, are responsible for their electricity imbalances	1 hour	See Annex II, Case Study 6

Most CPs calculate the imbalance as the difference between the metered and nominated volumes. The detailed methodology for calculating the imbalance in Georgia, North Macedonia, and Ukraine is provided in Annex II: Case Studies 2, 5 and 6. Table 13 shows that most CPs define positive and negative imbalances similarly: a positive imbalance represents the BRP surplus, while a negative imbalance represents the BRP shortage, in line with the EnC EBGL Regulation.

Table 13. *Definition of the positive and negative imbalance*

Contracting Party	*Definition of the positive and negative imbalances*
Albania	Imbalances of a BRP with metering points for a settlement period are defined as follows: 1. *Negative (-) imbalances occures* when: a. Actual production is lower than scheduled production for a settlement period, or b. Actual consumption is higher than scheduled consumption for a settlement period. 2. *Positive (+) imbalances occures* when: a. Actual production is higher than scheduled production for a settlement period, or b. Actual consumption is lower than scheduled consumption for a settlement period. A positive imbalance represents a BRP surplus, while a negative imbalance indicates a BRP shortage.
Bosnia and Herzegovina	Positive BRP imbalance means that BRP realized a balance energy surplus. A negative BRP imbalance means that BRP realized balance energy deficit.

[23] See Annex II, Case Study 5 for more details

Contracting Party	Definition of the positive and negative imbalances
Georgia	Aggravating Imbalance: An imbalance of a Balance Group that increases the electricity system's overall imbalance within the ISP; Mitigating Imbalance: An imbalance of a a Balance Group that reduces the electricity system's overall imbalance within the ISP.
Kosovo*	Positive imbalances occure when a BRP has a surplus, and negative imbalances occure when a BRP has a deficit.
Moldova	A positive imbalance represents a BRP surplus, while a negative imbalance represents a BRP shortage.
Montenegro	In contrast to the EU "convention", a positive imbalance indicates that the BRP consumed more than declared, meaning the producer generated less than declared (a BRP shortage), while a negative imbalance indicates a BRP surplus.
North Macedonia	Visit Annex II, Case Study 5
Serbia	A positive imbalance is a surplus of energy, and a negative imbalance is a shortage of energy.
Ukraine	Positive and negative imbalances are defined in relation to the scheduled or contracted positions of the BRP. A positive imbalance represents a surplus of electricity, meaning the BRP has either generated more or supplied less electricity than its scheduled or contracted position. On the other hand, a negative imbalance represents a shortage of electricity, meaning the BRP has either generated less or supplied more electricity than its scheduled or contracted position.

In Kosovo*, the imbalance price is calculated as the weighted average price of activated bids or offers. In Serbia, the imbalance settlement price for each ISP is determined as the weighted price of activated explicit offers from the Tertiary regulation, engaged balancing energy from the contractual balancing reserve (in the case when the TSO purchases balancing energy from TSOs from other market areas, suppliers or wholesale suppliers), engaged Secondary regulation, and electricity traded in the imbalance netting process within the International Grid Control Cooperation (IGCC).

Table 14. *Imbalance price calculation and cost for procurement balancing capacity*

	AL	BA	GE	XK*	MD	ME	MK	RS	UA
The imbalance price is calculated based on the price of activated balancing energy	✓	✓	✓	✓	✓	✓	✓	✓	✓
Two prices for positive and negative imbalances	✓	✓	-	-	✓	-	✓	✓	✓
Imbalance price depends on the direction of the system	-	-	-	✓	✓	-	-	-	✓
Financial neutrality of TSO with regard to the provision of	✓	✓	✓	✓	✓	✓	✓	✓	✓

balancing energy ensured									
TSO costs for procurement of balancing capacity are covered via tariff	✓	✓	✓	✓	✓	✓	✓	✓	✓

In all CPs, the imbalance price is calculated based on the price of activated balancing energy (as indicated in Table 14). In Bosnia and Herzegovina, when determining prices for positive and negative imbalances, the prices of local and cross-border balancing energy from FRR and the replacement reserve (RR), activated exclusively to balance the BIH load frequency control (LFC) area are used. however:

a) if no positive balancing energy is activated during an ISP for the purpose of balancing the BIH LFC area, the lowest price bid among those nominated for positive balancing energy aFRR is used as the price for negative imbalance;

b) if no negative balancing energy is activated during an ISP for the purpose of balancing the BIH LFC area, the highest price bid among those nominated for negative balancing energy aFRR is used as the price for positive imbalance;

c) if there are no bids for aFRR positive and negative balancing energy in the balancing energy market, the positive imbalance price is set to zero, and the negative imbalance price is the reference price, which equals the price realized to compensate for transmission losses in the relevant ISP.

Among all CPs, Georgia, Kosovo* and Montenegro apply a single imbalance price for positive and negative imbalances (as illustrated in Table 14). In Montenegro, there is a single base imbalance price; however, based on the value of the imbalance and the final system position, this price can be multiplied by certain coefficients (see Annex II, Case Study 4 for more details). In Moldova, the TSO calculates the separate negative and positive imbalance prices for each ISP. In North Macedonia, two prices for positive and negative imbalances are applied in case where there is no activated aFRR or mFRR. The previously mentioned methodology for the harmonization of the main features of imbalance settlement requires the application of single imbalance pricing, with dual pricing allowed in specific cases upon the approval of the regulatory authority.

Similar to Montenegro, the imbalance price in some other CPs depends on the direction of the system imbalance. In Ukraine, the imbalance price depends on the direction of the system imbalance in the case of using the imbalance price for the calculation of BRPs debit/credit. In Moldova, the price for imbalance electricity in the case of a deficit is the maximum of the actual cost of activated balancing electricity or the multiplication of the Ukrainian DA market price and a coefficient. In the case of positive imbalances, the TSO chooses the lower value between the revenue from activated balancing electricity or the multiplication of Ukrainian DA market price and a coefficient. Currently, the value of this coefficient used by the TSO considers the direction of the system imbalance. In North Macedonia, the imbalance price depends on the net summary of activated aFRR and mFRR.

The direction of payment for positive and negative imbalances is generally similar across all CPs. In the case of a positive imbalance for the BRP, the BRP receives the payment from the TSO, while in the case

of a negative imbalance, of the BRP, the BRP pays to the TSO.

All CPs ensure that TSOs remain financially neutral regarding the provision of balancing energy, which is aligned with the requirement of the EnC EBGL Regulation. The relevant legal framework and the imbalance price calculation formula guarantee this neutrality. According to the imbalance price calculation formula in Georgia, the value of all activated balancing energy amounts in ISP equals the net income and expenses of the balancing market operator for activated reserves. For the TSO, the sum of all payables equals the sum of all receivables. Similarly, in Montenegro, the imbalance price aims to recover the TSO's costs and disburse the revenue the TSO received from balancing the system. In Moldova, article 707 of the WEMR provides a mechanism that ensures that with the exemption of a small share, all additional revenues/costs registered by the TSO are distributed to market participants, includingfinal consumers (suppliers).

In North Macedonia, the costs for balancing energy are to be transferred to the BRPs. If the regulatory authority, in the process of setting an annual transmission tariff, detects that the TSO has not been financially neutral, the former will act on it respectively. In Ukraine, the Electric Energy Balancing Account (A-A) and Electric Energy Imbalances Account (A-B) are linked to the same TSO bank account with a special mode of use and are not revenue neutral (debits and credits do not balance).

As illustrated in Tabel 14, the NRAs of all CPs secure that TSOs' costs for procuring balancing capacity are covered by tariffs. In North Macedonia, the cost of procuring balancing capacity is included as part of the maximum allowed revenue as pass-through costs.

All TSOs have collateral requirements for the registration of balancing responsible parties. However, as shown in Table 15, all CPs define collateral differently; it can be long or short, a bank guarantee or a cash deposit.

Table 15. *Collateral requirement from TSO*

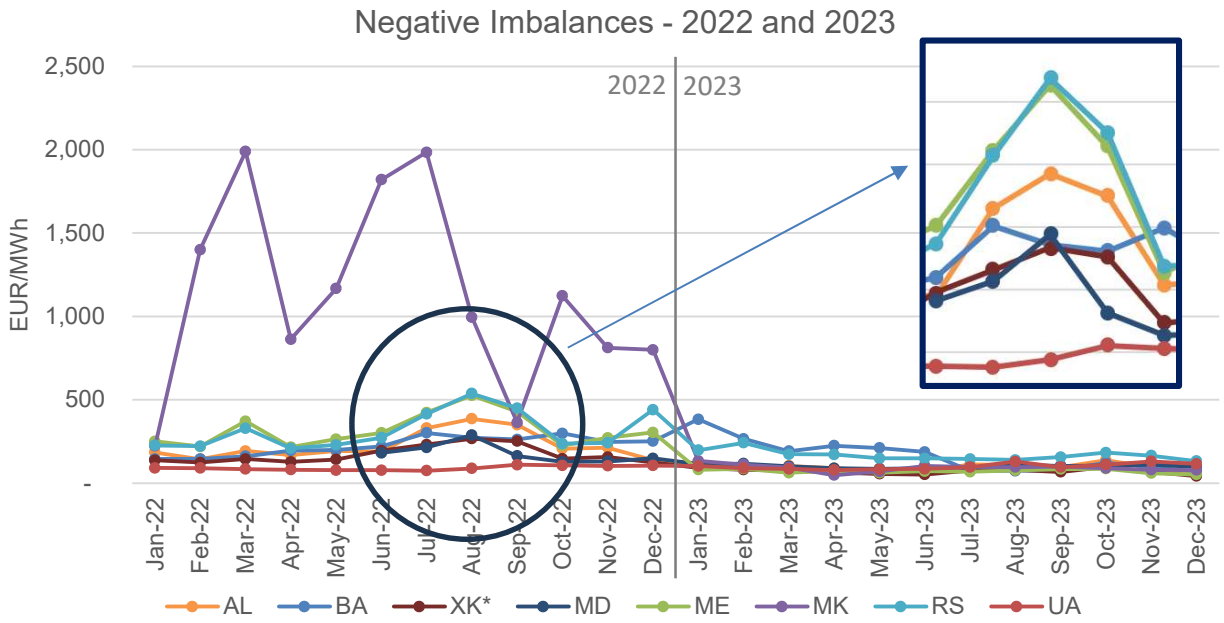
Contracting Party	Is there a collateral requirement from the TSO for the registration of the BRP?
Albania	As a suspensive condition for entering the BRP agreement, each BRP shall provide the TSO with a guarantee that meets the conditions for both the entire term of the BRP agreement and the entire duration of all financial obligations arising from its participation in the electricity balancing market. This guarantee may take the form of a bank guarantee or a cash payment to the TSO. The required level of financial security for each BRP should be up to 50% of the total net imbalance exposure calculated as average over the last three months.
Bosnia and Herzegovina	The amount of the bank guarantee or deposit is determined for a period of one calendar year as the greater of the following two values: a) the financial value of the planned average three-day electricity production of the BRP, calculated at the average imbalance price for electricity shortage in the year preceding the year for which the bank guarantee is issued, b) the financial value of the planned average three-day electricity consumption of the BRP, calculated at the average imbalance price for electricity shortages in the year preceding the year for which the bank guarantee is issued.

	At the same time, the amount of the bank guarantee or the deposit, cannot exceed 2 million BAM. In the event that there is no planned production or supply of electricity to end consumers within the balancing group, the BRP is not required to submit a payment security instrument but is obliged to sign a contract on balancing responsibility.
Kosovo*	It is defined but not applicable. Establishing the security cover mechanism is an ongoing process.
Georgia	The BRP is obliged to provide a financial guarantee three days before starting activity in the electricity wholesale market. The collateral submitted by the BRP to the TSO ensures compensation for any aggravating Imbalance caused by the BRP during the invoicing period. The BRP may submit collateral in the form of a deposit, bank guarantee, or another type approved by the TSO. Collateral may be either short-term or long-term. Short-term collateral must be valid for the remaining calendar days of the same invoicing period, plus at least 30 additional calendar days from the start date of the applicant's participation as a BRP in the wholesale electricity market. Long-term collateral must be valid for at least 150 calendar days from the date of the BRP's participation in the wholesale electricity market (See Annex II, Case Study 2)
Moldova	All market participants are registered as market participants and can operate in the market only after signing a balancing agreement with the TSO and establishing a financial guarantee calculated by the TSO according to a procedure approved by the NRA. In general, TSOs shall be financially balanced from the revenues/costs of balancing mechanisms, even when they apply a dual imbalance pricing mechanism, where the revenues from the imbalance mechanism are equal to the costs of balancing over a period of time. Such a financially balanced position is ensured through the reconciliation of the TSOs tariffs. In line with Regulation (EU) 2017/2195, costs related to the procurement of balancing capacity considered reasonable, efficient, and proportionate by the relevant regulatory authority shall be recovered through network tariffs.
Montenegro	The level of collateral is determined based on the risk value. The risk value is calculated as follows: a. If the BRP or balance group includes only customers, the risk value is determined as septuple average daily electricity consumption of this BRP or balance group during a six-month period multiplied by the base imbalance price; b. if the BRP or balance group includes only producers, the risk value is determined as septuple average daily electricity production of this BRP or balance group during a six-month period multiplied by the base imbalance price; c. if the balance group or BRP includes both buyers and producers, the risk value is determined based on the product of the greater of two values - septuple average daily production of electricity or fifteenfold average daily consumption of electricity during a six-month period multiplied by the base imbalance price; d. for traders who are not balancing responsible parties for consumers, producers or other traders, the risk value is calculated as septuple average daily transactions inside the control area of Montenegro during a six-month period multiplied by the base imbalance price, whereas the risk value cannot be higher than 50,000€; e. for the new BRP and Market Operator (who is the BRP for RES producers under the support scheme), the risk value is determined based on the forecasted average daily consumption, production or nominated capacity or

	electricity transactions in the case of traders. After the six months are finished, the risk value will be revised, i.e., set based on measured volume/quantities.
North Macedonia	Within seven business days after signing the Balancing Responsibility Agreement, the BRP shall submit the necessary financial guarantees to the TSO. There are fixed and variable bid securities. The amount of the fixed financial guarantee is 1,000,000 denars and may be submitted by the financial settlement participants as a cash deposit or a bank guarantee (See Annex II, Case Study 5).
Serbia	The value of the appropriate payment security instrument is determined on the basis of the established risk value, and it cannot be less than EUR 1,000,000.00, and greater than EUR 5,000,000.00 in case the value of Nmax is less than EUR 5,000,000.00. If Nmax is greater than or equal to EUR 5,000,000.00, the maximum value of the payment security instrument equals three times the value of Nmax. Nmax is the maximum value of the difference between the sum of the balancing group's monthly negative imbalance fee and the unbalanced daily schedules fees during the accounting period and the monthly fee for the engaged balancing energy for regulation up and within 12 months from the date of calculating the risk value.
Ukraine	According to the Market Rules, the market participants who are the BRPs are obliged to provide the TSO with financial guarantees in the form of cash or financial guarantees from banks meeting certain criteria. Recent changes to Resolution 332 designate that not less than 50% of guarantees must be in cash and the rest must be in the form of financial guarantees from any banking institution. Financial guarantees are provided for the fulfilment of obligations under the contracts related to imbalance settlement, subject to the registration on the relevant trading day of the volumes of electricity on Bilateral Contracts, the DA market, the ID market, and the physical supply/selection of electricity, declared in the market management system, as well as in the presence of consumers for whom the market participant is an active electricity supplier.

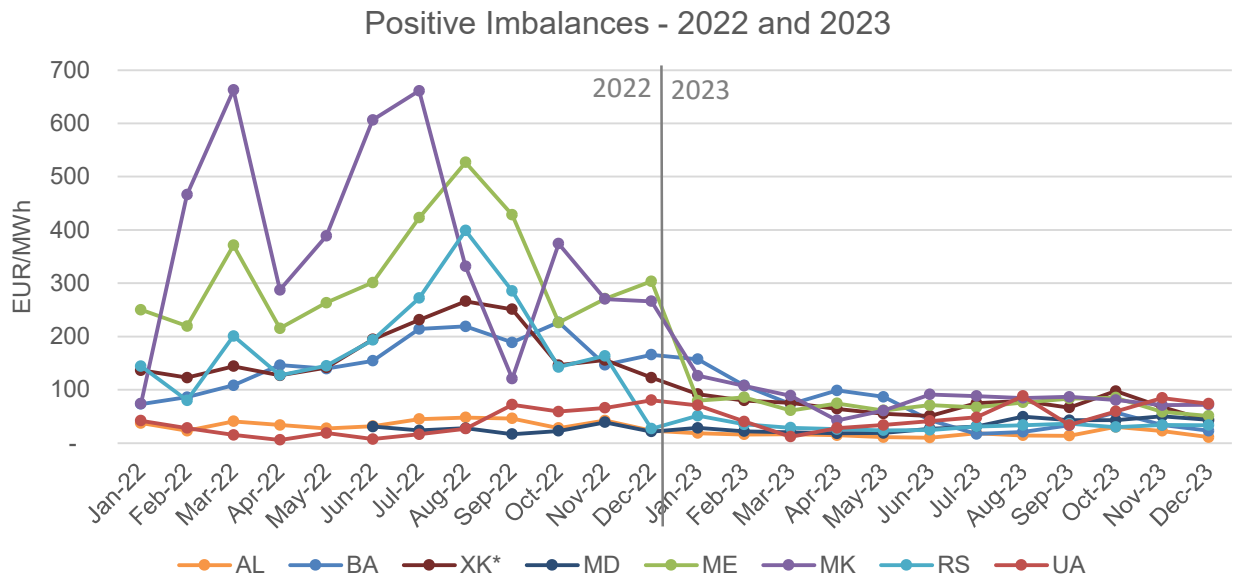
Figure 2 and 3 show the average monthly imbalance prices for positive and negative imbalances in 2022 and the first half of 2023.

Figure 5 Monthly average prices for negative imbalances[24] in 2022 and 2023



During 2022, average imbalance prices for negative imbalances reached extremely high values in North Macedonia. The imbalance prices were also varying in other CPs as shown in Figure 5, hitting the peak in August 2022. Since the beginning of 2023, the average imbalance prices declined in all Contracting Parties converging by the end of 2023 to the value under 150 EUR/MWh.

Figure 6 Monthly average prices for positive imbalances[25] in 2022 and the first half of 2023



[24] The negative imbalance represents the BRP shortage.
[25] The positive imbalance represents the BRP surplus.

Similarly, the average prices for positive imbalances showed declining trend from 2022 to 2023 in all CPs presented, converging by the end of 2023 to the value under 75 EUR/MWh.

Due to the latest price surge, in Serbia, there were changes in the limitation of bids for balancing energy and a change in the maximum value of collaterals.

Conclusions and Recommendations

From the beginning of 2024, the DA markets have been operational in six CPs (AL, XK*, ME, MK, RS and UA), using the marginal pricing principle to establish the wholesale electricity price. In all those markets, minimum and maximum limits to the wholesale price have been introduced. Products traded in most CPs are standardized with a time granularity of one hour. Some CPs have introduced GCT harmonized with SDAC – 12.00 day-ahead (AL, GE, XK* and UA), while the others opted for earlier GCT (ME, MK and RS).

In all WB6 CPs and Moldova and Ukraine, it is possible to allocate cross-zonal capacity in the DA timeframe. Since February 2024, the cross-zonal capacity allocation between Albania and Kosovo* has been performed implicitly, making it the only CP-CP bidding zone border where the capacity is allocated implicitly. Explicit daily auctions are performed either by SEE CAO, JAO or respective TSOs via web-based platforms where hourly products are offered. The practice for the obligatory requirement of providing collateral and nomination of allocated cross-zonal capacity varies from CP to CP.

Unlike the DA market, the ID market is only operational in Serbia and Ukraine. However, ID cross-zonal capacity allocation with neighbouring CPs and EU member states is possible in Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia, and Serbia, where the allocation is continuous and performed by the TSOs of relevant CPs or a Member State. In some CPs, ID cross-zonal GCT is one hour before the start of the relevant ID market unit, while in others, it is 90 minutes before the delivery hour.

When it comes to NEMO designation, only Albania, Kosovo*, North Macedonia, and Serbia have designated NEMOs. Since the designation of at least one NEMO is a requirement prescribed by EnC CACM and one of the preconditions for the integration into a single EU electricity market, the other CPs (BA, GE, MD, ME and UA) should intensify their activities on the designation of NEMOs in their countries. NEMO designation confirms that the requirements from Article 6 of EnC CACM are met. In line with the opinion of EC, ACER and EnCS, the NEMO designation becomes valid only after the transposition of the relevant legislation: Regulation 2019/943, Regulation 2015/1222, Regulation 2019/942, Directive 2019/944 and Regulation 1227/2011.

Parallel to NEMO designation, several market coupling initiatives are ongoing in the CPs, while there are indications that some new local implementation projects will be established soon. Since EnC NEMOs are supposed to join SDAC and SIDC via the local implementation projects, the establishment and operationalization of these projects should be boosted to allow for adherence to these projects in earlier windows. After joining SDAC and SIDC, the order matching and capacity allocation will be done simultaneously, i.e. the implicit allocation will apply.

As a general observation, almost all CPs have in place balancing mechanisms and associated rules on how TSOs shall balance the system. In most CPs, procurement of balancing services is done through a market-based mechanism, i.e., a transparent auction or tender where the best commercial/technical offers are accepted. In the majority of CPs, any market participant meeting the criteria and passing the

prequalification test can become a BSP. Moreover, some CPs have mandatory requirements for market participants to offer balancing services if they meet certain technical criteria.

Procurement of upward balancing capacity and downward balancing capacity is done separately for each direction in most CPs, which is also required by EnC Electricity and EBGL Regulation, except Montenegro, North Macedonia, and Serbia. All CPs ensure that TSOs remain financially neutral regarding the provision of balancing energy and that TSOs' costs for procuring balancing capacity are covered by tariff.

In general, all market participants are responsible for the imbalances they cause in the system, which is aligned with the requirement of EnC Electricity Regulation. However, some CPs have exceptions for RES producers or RES producers benefiting from support schemes. After the transposition of the EnC Electricity Regulation, the derogations from balance responsibility will have to be limited to cases prescribed by this regulation. Regarding the imbalance settlement mechanism, the approaches for the calculation of the imbalance prices vary among CPs. However, after the transposition of EnC EBGL Regulation, CPs will have to align the main features of the imbalance settlement mechanism with the previously mentioned Methodology approved by ACER.

In conclusion, this report highlights the significant steps made in the development and operation of DA and ID and balancing electricity markets across CPs. However, all CPs are yet to transpose the Electricity Integration Package, i.e., align the national legal frameworks with EnC Electricity Regulation, EnC CACM Regulation and EnC EBGL Regulation, which will lead to further harmonization of the DA, ID and balancing market rules and enable adhesion to SDAC, SIDC and balancing platforms.

Annex I. Interconnection Data 2023 & 2022 [26] [27] [28]

Table 16: Detailed 2023 data and aggregated 2022 data

2023						2022
Direction	Max NTC	Thermal capacity	Total of allocated capacity on all time frames: long term (annual/month), day ahead, intraday	Average price per border direction	Congestion incomes per border direction	Congestion incomes per border direction
	GW	GW	GWh	EUR/MWh	EUR	EUR
AL-ME	0.30	0.30	4,855	1.71	8,317,118	3,504,104
ME-AL	0.30	1.56	4,886	1.16	5,670,442	5,953,326
AL-GR	0.40		1,643	4.94	8,119,543	3,854,890
GR-AL	0.40		1,576	2.85	4,494,140	3,947,012
AL-XK*	0.50	1.54	6,370	0.79	5,007,255	1,660,832
XK*-AL	0.58	1.25	6,181	0.73	4,491,935	4,008,855
BA-HR	0.75	5.28	8,366	0.78	6,557,030	5,088,303
HR-BA	0.75	5.28	9,786	0.11	1,108,317	922,434
BA-RS	0.60	1.41	7,269	0.91	6,590,353	4,303,345
RS-BA	0.60	1.41	10,146	0.08	814,494	609,087
BA-ME	0.50	2.00	7,521	2.06	15,454,803	19,034,387
ME-BA	0.50	2.00	8,590	0.58	4,977,301	2,844,522
GR-MK	0.50	0.17	7,776	0.82	6,377,012	6,619,186
MK-GR	0.50	2.28	4,463	5.12	22,842,681	16,421,010
BG-MK	0.45	1.84	3,585	4.30	15,433,357	26,296,616
MK-BG	0.45	0.08	6,519	0.32	2,070,140	63,028
XK*-MK	0.45	0.15	6,290	0.16	1,003,929	724,344
MK-XK*	0.45	1.37	5,406	1.81	9,761,460	4,278,359
ME-XK*	0.40	1.25	5,001	0.58	2,924,784	3,370,040
XK*-ME	0.42	1.25	3,697	0.74	2,748,625	3,270,646
MD-RO	0.20	1.19			270,000	
RO-MD	0.60	1.19				
ME-IT	0.6	2.56	6,491	5.33	34,574,652	24,002,819
IT-ME	0.60	2.13	8,695	1.57	13,613,816	9,610,117
RS-ME	0.5	0.88	5,134	2.66	13,647,360	18,469,394
ME-RS	0.4	0.76	4,676	2.53	11,851,244	5,019,809
MK-RS	0.6	1.144	9,570	1.04	9,922,717	18,437,694
RS-MK	0.6	1.144	6,555	2.14	14,052,646	15,718,511
RS-HR	0.6	1.144	6,251	1.15	7,165,427	6,084,056
HR-RS	0.6	1.144	6,873	0.75	5,182,488	4,134,596

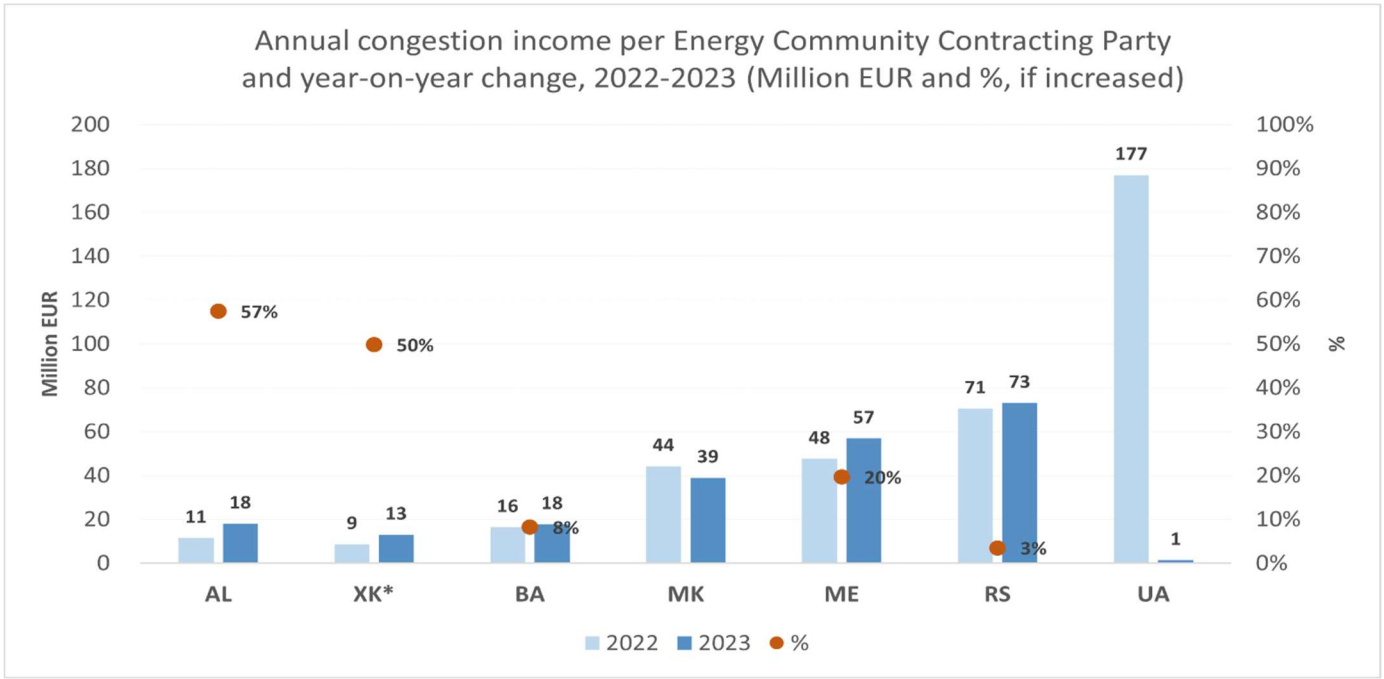
[26] RS-XK*/XK*-RS no allocation

[27] At the moment allocations on the RO-MD border are made only on a daily basis (no long term capacity allocation)

[28] Comments to data on Ukraine: Coordinated joint allocation on UA-RO border is implemented from the delivery day of 03/11/2023; Allocation on RZE(PL)-KhNPP(UA) border is implemented from the delivery day of 15/05/2023; Allocation on all borders in 2023 was made only on daily basis

RS-BG	0.45	1.148	6,919	0.52	3,602,092	1,776,000
BG-RS	0.45	1.148	5,667	4.32	24,474,366	31,931,051
RS-RO	0.7	1.032	7,437	0.10	730,657	1,921,958
RO-RS	0.7	1.032	7,056	1.10	7,784,967	9,166,887
RS-HU	1	1.144	13,582	2.02	27,404,204	12,224,768
HU-RS	1	1.144	13,732	0.94	12,875,831	11,364,540
UA-MD	0.8		580	0.28	162,436	9,254
MD-UA	1.2		1,585	0.03	41,819	0
UA-PL	0.265		40	0.00	0	16,235.10
UA-SK	0.7	1.3	183	2.36	431,985	86,013,122
SK-UA	0.7	1.3	1,960	0.20	393,453	128
UA-SK-35	0.1		0		0	0
UA-HU	0.65		0		0	12,829,005
HU-UA	0.68		0		0	0
UA-RO	0.4	1.1	17	1.96	33,363	78,142,620
RO-UA	0.4	1.1	212	1.53	323,919	127
UA(KhNPP)-PL(RZE)	0.4	0.7	17	0.74	12,596	
PL(RZE)-UA(KhNPP)	0.4	0.7	1,585	0.00	16	

Table 17: *Aggregated 2023 and 2022 data*



Annex II. Balancing mechanisms in CPs

Case Study 1: Balancing mechanism in Bosnia and Herzegovina

Pricing balancing capacity and energy

The price cap for secondary control reserve capacity is defined with the aim of protecting market participants, primarily the customers, under the conditions of insufficiently developed competition. The price cap for secondary control reserve capacity shall equal to the product of the secondary control reserve capacity base price and predefined coefficient k_{SecCap} which ensures sufficient incentives to suppliers to provide secondary control reserve capacity:

$$p_{MaxSecCap} = k_{SecCap} \times p_{BaseSecCap};$$

$$1.1 \leq k_{SecCap} \leq 1.5.$$

The secondary control reserve capacity base price is equal to the higher value between the fixed costs of the most expensive generating unit providing the secondary control service and the market value of capacity which is used to provide the ancillary service of automatic secondary control:

$$p_{BaseSecCap} = \max(\text{capital costs, market value}).$$

The market value of secondary control reserve capacity is calculated in a different manner depending on the type of market bidding procedure, i.e. whether it is annual or monthly, based on annual and monthly forward prices in the electricity exchange. The market value is limited within the following range:

$$10\ €/MW/h \leq \text{market value} \leq 40\ €/MW/h.$$

The price cap and input parameters for its setting are published by SERC, at least 10 days before the beginning of the market procedure for purchasing secondary control reserve capacity.

With the aim of protecting the competition mechanism, the price cap for upward and downward manual frequency restoration reserves are defined as:

$$\text{Upward: } p_{MaxTerCapUp} = k_{TerCap} \times p_{TerCap};\quad 1.1 \leq k_{TerCap} \leq 1.5;$$

$$\text{Downward: } p_{MaxTerCapDow} = 0.25 \times k_{TerCap} \times p_{TerCap};\quad 1.1 \leq k_{TerCap} \leq 1.5.$$

The price caps and basic input parameters for their setting are established by SERC.

The difference between the bid price of upward secondary control energy $p_{SecEnUp}$ and the price of downward secondary control energy $p_{SecEnDow}$ in a specific hour is within the regulated scope, that is, lower than or equal to a maximum value of this difference S (€/MWh):

$$p_{SecEnUp} - p_{SecEnDow} \leq S.$$

The value of S is determined by SERC.

The price of balancing energy for upward mFRR $p_{TerEnUp}$ and balancing energy for downward mFRR pTerEnDow are limited with the aim of protecting the market competition. The price cap for balancing energy for upward mFRR is equal to the product of the value of the electricity reference price in the market p_{MR} and coefficient $k_{MaxTerEnUp}$:

$$p_{MaxTerEnUp} = k_{MaxTerEnUp} \times p_{MR}.$$

The price cap for balancing energy for downward mFRR $p_{MaxTerEnDow}$ is equal to the negative product of the value of the electricity reference price in the market p_{MR}.

Imbalance price calculation:

For each settlement period, the price for positive and negative imbalance shall be determined.

Positive Imbalance Price shall be determined as follows:

$$C+=\{ k+*\min(C_{DOWNBalEn}),\ C_{DOWNBalEn} \geq 0 \text{ or } 1/k+*\min(C_{DOWNBalEn}),\ C_{DOWNBalEn} < 0\}$$

Where:

$C_{DOWNBalEn}$ shall be the lowest price for activated downward balancing energy FRR and RR in a settlement period,

$k+$ shall be a coefficient that shall be determined by SERC in a Decision on Ancillary Services.

Negative Imbalance Price shall be determined as follows:

$$C-=k-*\max(C_{UPBalEn})$$

Where:

$C_{UPBalEn}$ shall be the highest price for activated upward balancing energy in a settlement period,

$k-$ shall be a coefficient that shall be determined by SERC in a Decision on Ancillary Services,

When determining prices for positive and negative imbalances the prices of activated local and cross-border balancing energy of FRR and RR which are activated exclusively to balance the BIH LFC area are used.

In the event that no activation of positive balancing energy has occurred during an ISP for the purpose of balancing the BIH LFC area, the lowest price bid out of those nominated for positive balancing energy aFRR is used as the price for negative imbalances.

In the event that no activation of negative balancing energy has occurred during an ISP for the purpose of balancing the BIH LFC area, imbalance the highest price bid out of those nominated for negative balancing energy aFRR is used as the price for positive.

In the event that there have not been aFRR positive and negative balancing energy bids in the balancing energy market, the positive imbalance price shall be equal to zero, and the negative imbalance price shall be the reference price equal to the price realized to compensate transmission losses for the relevant ISP.

Case Study 2: Calculation of imbalance, imbalance price and collateral in Georgia

Imbalance Calculation

Imbalances (MWh) by Balancing Groups are calculated following the formula:

$$Q_{BG,IMB,ISP} = Q_{BG,IN} - Q_{BG,OUT} + Q_{BG,PUR,ISP} - Q_{BG,SOLD,ISP}$$

Where:

$Q_{BG,IMB,ISP}$ – imbalance of BG in ISP,
$Q_{BG,IN}$ – Metered amount of electricity injected into grid by BG in ISP,
$Q_{BG,OUT}$ – Metered amount of electricity received from the grid by BG in ISP,
$Q_{BG,PUR,ISP}$ – is the amount of electricity purchased by BG in ISP (sum of: electricity purchase nominations by BG in ISP and amount of activated balancing energy (downregulating bids)),
$Q_{BG,SOLD,ISP}$ - is the amount of electricity sold by BG in ISP (sum of: electricity purchase nominations by BG in ISP and amount of activated balancing energy (upregulating bids)

System Imbalance (**QSYS,IMB,ISP**) is equal to the netted amount of all Balancing Group imbalances.

Imbalance price calculation

Imbalance price is calculated (for each ISP) following the formula:

$$P_{imb,ISP} = \frac{NTR_{BE,ISP}}{Q_{SYS,IMB,ISP}}$$

Where:

NTRBE, ISP - is the value (Georgian Lari) of all activated balancing energy amounts in ISP and equals to net of income and expenses of balancing market operator for activated reserves (aFRR, mFRR, ER) and unintended deviations of cross-border flows,

QSYS,IMB,ISP - is equal to the netted amount of all Balancing Group imbalances.

Collateral Calculation

Collateral may be short-term or long-term. The short-term collateral shall be valid for the remaining calendar days of the same invoicing period, plus at least 30 calendar days from the date of the applicant's participation as a BRP in the wholesale electricity market. The amount of short-term collateral for each invoicing period shall be calculated by the following formula:

$$COLL = F_{sys.error} * E_m * P_m$$

The long-term collateral shall be valid for a period of at least 150 calendar days from the date of participation of the BRP in the wholesale electricity market, and its amount shall be calculated according to the following formula:

$$COLL=F_{sys.error}*MAX(E_{m1}; E_{m2}; E_{m3}; E_{m4})*P_m$$

Where:

COLL – amount of the collateral;

$F_{sys.error}$ – the median indicator of the difference in percentages between the hourly plan and the actual consumption of electricity in the electric power system for the last year, which is established by the transmission system operator and published on its website;

E_m – generated/consumed/supplied electricity individually on the busbar of the facility/supplier/network operator within the balance group/groups of the BRP of the corresponding invoicing period of the previous year (in which invoicing period the applicant (seeker)/ BRP is required to submit collateral), and for network operators - loss in the network - the absolute sum of the product of the average daily volume of electricity and the remaining calendar days in the invoicing period in megawatt-hours, and in the absence of such - forecast data calculated in an identical manner;

Note: In the event that the power plant, instead of/in addition to the production of electricity, intends to consume more than one megawatt-hour of electricity in a specific invoicing period, it shall submit the relevant forecast data to the TSO. In addition, if in the same invoicing period of the last year, the power plant records both the supply and consumption of electricity at the busbar, the absolute sum of the accounting data of electricity supply and consumption at the busbar will be taken into account in the E_m component when calculating the collateral.

$MAX(E_{m1}; E_{m2}; E_{m3}; E_{m4})$ – The greatest value of the E_m components of the first four invoicing periods;

P_m – the average hourly price of imbalance for the last completed invoicing period;

$F_{sys.error}$ and P_m - the values available at the moment of determining the amount of the financial guarantee shall be taken into account as components.

Case Study 3. Imbalance price calculation in Moldova

For the calculation of imbalance prices, TSO is referring to the provision of art. 690 and 691 of the EMR. Thus, the price for the negative imbalance is calculated by using the following formula:

$$P_{DEF}(i) = Max\ f_{i,def} \times PIP(i);\ \frac{R_C(i)}{\sum t \in S_{mFRR,C(i)}\ q_{livrat(t,i)} + \sum t \in S_{RR,C(i)}\ q_{livrat(t,i)}}$$

Where:

$f_{(i,def)}$ - factor for the negative imbalances of the BRP/balancing group, greater than or equal to 1 (one), established by the Agency, within a Decision. The imbalance factors used at the moment were approved by the Decision of the ANRE Board of Directors no. 388 of June 30, 2023;

PIP(i) - The market closing price for the national trading area (hereinafter – PIP), which represents the price at which transactions are concluded on the DA market in a certain trading interval. It should be mentioned here that, in accordance with point 780 of the EMR until the launch of the DA market, TSO will use in the settlement process of BRP imbalances the market closing price applicable to the respective dispatch interval obtained on the DA market in Ukraine;

$R_{C\ (i)}$ - the cost for balancing the system at power increase ("RC(i)") in the dispatch interval "i" determined according to the provisions of section 4 of Chapter 4 of the EMR (at the moment the figure is coming from Amprion);

$q_{livrat(t,i)}$ - the amount of balancing electricity delivered as a result of transaction "t", in the dispatch interval "i";

$S_{(mFRR,C(i))}$ - all balance power delivery transactions corresponding to the manual step-up frequency restoration process that was used to balance the system in dispatch interval "i";

$S_{(RR,C(i))}$ - all transactions for the delivery of balancing electricity corresponding to the process of replacing the power increase reserves that were used to balance the system in the dispatch interval "i";

Subsequently, the price for positive imbalance is calculated using the following formula:

$$P_{EX}(i) = Min\ f_{i,sur} \times PIP(i);\ \frac{R_R(i)}{\sum t \in S_{mFRR,R(i)}\ q_{livrat(t,i)} + \sum t \in S_{RR,R(i)}\ q_{livrat(t,i)}}$$

Where:

$f_{(i,sur)}$ - factor for the positive imbalances of the BRP/balancing group, lower than or equal to 1 (one), established by the Agency, within a Decision. The imbalance factors used at the moment were approved by the Decision of the ANRE Board of Directors no. 388 of June 30, 2023;

PIP(i) - The market closing price for the national trading area (hereinafter – PIP), which represents the price at which transactions are concluded on the DA market in a certain trading interval. It should be mentioned here that, in accordance with point 780 of the EMR until the launch of the DA market, OST will use in the settlement process of BRP imbalances the market closing price applicable to the respective dispatch interval obtained on the DA market in Ukraine.

$R_{C\ (i)}$ - the revenue for balancing the system at downward regulation ("RR(i)") in the dispatch interval "i" determined according to the provisions of section 4 of Chapter 4 of the EMR;

$q_{livrat(t,i)}$ - the amount of balancing electricity delivered as a result of transaction "t", in the dispatch interval "i";

$S_{(mFRR,C(i))}$ - all balance power delivery transactions corresponding to the manual de-power frequency restoration process that was used to balance the system in dispatch interval "i";

$S_{(RR,C(i))}$ - all transactions for the delivery of balancing electricity corresponding to the process of

replacing the power reduction reserves that were used to balance the system in the dispatch interval "i".

Case Study 4. Imbalance price calculation in Montenegro

The base imbalance price for both positive and negative imbalances is calculated as follows to ensure that financial neutrality of the TSO:

$$P_o = \frac{C_s + C_t + C_{fskar} + C_{in}}{E_s + E_t + E_{fskar} + E_{in}}$$

Where:

C_s, C_t, C_{fp}, C_{in} *- TSO's costs or revenues for the procurement of balancing energy from secondary reserve, tertiary reserve, Fskar and imbalance netting;*

$E_s, E_t, E_{fskar}, E_{in}$ *– Corresponding volume of procured energy.*

However, based on the value of imbalance of the specific BRP taking into account to the tolerance range and the final position of the system, base price can be multiplied with certain coefficient (1,5 for positive imbalances and 0,5 for negative imbalances:

BRP imbalance - system imbalance	**BRP imbalance value (with regards to the tolerance range)**	**Imbalance price**
Opposite direction (positive – negative/ negative – positive)	within	Base imbalance price
	outside	
Same direction (positive – positive/ negative – negative)	within	Base imbalance price
Same direction (positive – positive)	outside	1,5* Base imbalance price
Same direction (negative – negative)		0,5* Base imbalance price

Case Study 5: Balancing mechanism in North Macedonia

BSP prequalification process

The Balancing rules describe the process for pre-qualification of the BSPs before they offer balancing services.

The BSP registration procedure begins with the submission of an application to the TSO. The request for registration of BSP, which TSO publishes on its website, contains:

- Information on the concluded Agreement for participation in the electricity market concluded with the electricity market operator,
- Name, address, contact data and EIC code,
- Names and data of all authorized persons who represent the applicant during the implementation of the registration procedure on the balance energy market,
- List of all balance units that meet the criteria for providing an appropriate balancing service with which the applicant intends to participate in the balance energy market,
- Form for submitting the dynamic parameters of the balance units.

After TSO confirms that the Request is complete, within three months of submitting the request, it conducts the necessary tests and decides whether the potential BSP meets the qualification criteria. If the applicant meets the qualification criteria, the TSO signs the BSP Agreement and delivers it to the

applicant.

After receiving the signed Balancing Agreement, the TSO enters the electricity market participant in the Register of BSPs as a participant in the balancing energy market, thereby acquiring the right to participate in the balancing energy market as a BSP. BSP submits a bank guarantee to the TSO.

TSO has the right to request the retesting of BSP balance units for FCR, aFRR, or mFRR:

- At least once every five years.
- In case of a change in the technical requirements or the requirements for the availability of the equipment.
- In case of modernization of the equipment for activation of FCR, aFRR, or mFRR
- In case if it does not meet the necessary technical requirements.

TSO prepares and publishes the Dynamic Parameters Submission Form of BSP's balancing units (DPSF) on its website, and it should contain at least the following:

1) Type of generation unit and brief description (model, constraints, etc.),
2) Rated power expressed in MW,
3) Permissible overload expressed in MW,
4) Minimum level of variable load expressed in MW,
5) Normal and critical speed of output power increasement expressed in MW/min,
6) Normal and critical reduction speed of output power expressed in MW/min,
7) Minimum time for shutdown from full load conditions, expressed in minutes,
8) The minimum time required for restart from a cold to a hot state expressed in minutes,
9) Available capacity for a primary reserve,
10) Available capacity for a maximum and minimum secondary reserve,
11) Available capacity for a tertiary reserve,
12) Availability for a startup in a state of total loss of power(black-start).

For consumers in the role of a balancing unit, the DPSF form should contain at least:

1) Peak power expressed in MW,
2) Points of connection,
3) Minimum level of variable load expressed in MW,
4) Maximum level of variable load expressed in MW,
5) Normal and critical speed of output power increasement expressed in MW/min,
6) Normal and critical reduction speed of output power expressed in MW/min,
7) The maximum level of load which can be cut off expressed in MW,
8) The maximum duration of the load cut off expressed in minutes

Imbalance calculation

The Electricity Market Operator makes a preliminary imbalance settlement for each balancing group as a difference between the total realized electricity exchange and the announced (nominated) exchange of that balancing group, for each ISP:

$$W_{imbalances} = W_{final\ position} - W_{allocated\ volume} - W_{activated\ balancing\ volume}$$

Where:

- $W_{imbalances}$ - *the total imbalance amount for the Balancing Group;*
- $W_{final\ position}$ - *the nominated electricity exchange for the Balancing Group;*
- $W_{allocated\ volume}$ - *the total finished electricity exchange of the Balancing Group;*

$W_{activated\ balancing\ volume}$ - *the total activated balancing energy of the BSPs included in the balancing group, which may have a positive sign for activated balancing energy for up regulation or a negative sign for activated balancing energy for down regulation.*

(1) $W_{imbalances}$ could be positive or negative.

1) The positive imbalance of the Balancing Group means that the total electricity consumed by the Balancing Group is less than the nominated electricity of the Balancing Group (lower consumption or higher generation than planned).
2) The negative imbalance of the Balancing Group means that the total electricity consumed is greater than the nominated electricity of the Balancing Group (higher consumption or lower generation than planned).
3) The announced electricity exchange of a Balancing Group Member is the difference between the sum of purchase and import transactions on one side and the sales and export transactions on the other side that are delivered according to confirmed daily schedules for each ISP:

$$W_{final\ position} = \left(\sum W_{buy} - \sum W_{sell}\right) + \left(\sum W_{import} - \sum W_{export}\right)$$

Where:

$W_{final\ position}$ - *the total announced electricity exchange of a Balancing Group Member;*

W_{buy} - *the amount of electricity that each Balancing Group Member receives from other electricity market participants in the regulatory area in the accounting interval;*

W_{sell} - *the amount of electricity that each Balancing Group Member transfers to other electricity market participants in the regulatory area in the accounting interval.*

W_{import} - *the amount of electricity that each Balancing Group Member imports during cross-border exchange at hour i;*

W_{export} - *the amount of electricity that each Balancing Group Member exports during cross-border exchange at hour i;*

4) the total nominated electricity exchange of the Balancing Group for each ISP is calculated as the transactions sum of all Balancing Group Members

$$W_{final\ position\ of\ BG} = \sum_{i=1}^{n} W_{finil\ position\ i}$$

Imbalance price calculation

TSO calculates imbalance setting prices ($C_{imbalances}$) based on the prices of activated balancing energy and the quantity of activated balancing energy.

Quantities of activated balancing energy for each period of imbalance setting	***Price of imbalance setting*** $C_{imbalances}$
The quantity of activated balancing energy exceeds the quantity of activated negative balance energy $W_{pos} + W_{neg} > 0$	WAP_{pos}
The quantity of activated negative balancing energy exceeds the quantity of activated positive balance energy $W_{pos} + W_{neg} < 0$	WAP_{neg}
There is no activated balancing energy or $W_{pos} + W_{neg} = 0$	VAA

Where:

WAP_{pos}- the price of activated balancing energy for each period of imbalance setting;
WAP_{neg} - the price of activated negative balancing energy for each period of imbalance setting;
VAA - the price of inactivated balancing energy for each period of imbalance setting;

W_{pos} - the quantity of activated positive balancing energy;
W_{neg} - the quantity of activated negative balancing energy.

The cost of each BRP is calculated by TSO based on the calculation of imbalances for each calculation period. For calculating the price of imbalance setting a mechanism of unique price is used, i.e., for positive and negative imbalances the price $C_{imbalances}$ shall be used:

The price of activated positive balancing energy shall be calculated for each period of imbalance setting, in line with the prices of aFRR, mFRR and RR by applying the formula below:

$$WAP_{pos,i} = \frac{\sum_{1}^{n}{}_{type}(Price_{pos,type,i} \cdot W_{pos,type,i})}{\sum_{1}^{n}{}_{type} W_{pos,type,i}}$$

Where:

WAP_{pos} - the price of activated positive balance energy for each period of imbalance setting;
$Price_{pos,type,i}$ - the price of activated positive secondary and/ tertiary balancing energy for each period of imbalance setting;
$W_{pos,type,i}$ - the quantity of activated positive secondary and/or tertiary balancing energy for each period of imbalance setting;
n - balance unit;
type - secondary or tertiary balance energy.

The price of activated negative balancing energy shall be calculated for each period of imbalance setting of prices of aFRR, mFRR and RR by applying the formula below:

$$WAP_{neg,i} = \frac{\sum_{1}^{n}{}_{type}(Price_{neg,type,i} \cdot W_{neg,type,i})}{\sum_{1}^{n}{}_{type} W_{neg,type,i}}$$

Where:

WAP_{neg} - the price of activated negative balancing energy for each period of imbalance setting;

$Price_{neg,type,i}$ *- the price of activated negative secondary and/tertiary balancing energy for each period of imbalance setting;*
$W_{neg,type,i}$ *- the quantity of activated negative secondary and/or tertiary balancing energy for each period of imbalance.*
Type - secondary or tertiary balancing energy.

If there is a positive or negative imbalance of BRP, and the quantity of activated balance energy is zero ($W_{pos} + W_{neg} = 0$), the price of imbalance setting of BRP shall be regulated as follows:

	Prices of imbalance setting
Positive imbalance of BRP	ETSO pays to BRP, HUPX – 50%
Negative imbalance of BRP	BRP pays to ETSO, HUPX+ 50%

After collecting all necessary data for calculating the prices of imbalance setting, TSO shall publish on its web page all the data on calculated values of the price of imbalance setting $C_{imbalances}$ for each imbalance period separately.

Collateral

There is a collateral requirement for BRPs defined in the Rules for balancing of the power system.

Within seven (7) business days after signing the Balancing Responsibility Agreement, BRP shall submit the necessary financial guarantees to TSO.

There is a fix and variable bid security. The amount of the fixed financial guarantee is 1.000.000 denars and may be submitted by the financial settlement participants in the form of a cash deposit or a bank guarantee.

Before the expiration of the validity of the variable financial guarantee the BRP is obliged to renew it at the request of TSO.

a) For the BRP that is registered for the first time, the amount of the variable financial guarantee will be 1,500,000 denars.
b) If the BRP is registered as such for more than 4 months and less than 13 months to the moment of renewal of the variable financial guarantee, the amount of the variable financial guarantee is calculated as an amount that is twice the amount of the average invoiced value of the BRP for the imbalances made in the previous months from its registration.
c) If the BRP is registered as such for more than 13 months until the renewal of the variable financial guarantee, the amount of the variable financial guarantee is calculated as an amount that is twice the amount of the average invoiced BRP value for the imbalances made in the previous 12 months.

The average invoiced value of the BRP for the imbalances mentioned above is calculated as an average value of the amounts only from the months in which the BRP has financial liabilities to TSO, i.e. TSO submits an invoice for imbalance payments.

If the financial guarantees already submitted by the BRP are lower than the amount of the last issued invoice for imbalance settlement, the BRP is obliged at the request of TSO to submit a new or to complement the existing variable financial guarantee. The amount of the new variable financial guarantee is calculated as the difference between the amount of the invoice issued in the last month and the amount of the fixed financial guarantee.

If the financial guarantees already submitted by the BRP are higher than the amount of the last issued invoice for imbalance settlement, the submitted variable financial guarantee does not change.

The BRP is obliged to submit a new variable financial guarantee within 8 business days from the submitted request for an increase of the amount of the variable bank guarantee by the TSO.

After signing the Balancing Responsibility Agreement, the BRP submits both the fixed and the variable financial guarantee at the same time.

Case Study 6: Balancing mechanism in Ukraine

Imbalance Calculation

The imbalance for settlement period t in zone z of BRP b is calculated using the formula:

$$IEQ_{b,z,t} = \sum_{e \in b} \left(FPQ_{e,z,t} - INST_{e,z,t} \right) + MP_{b,z,t} - NP_{b,z,t}$$

Where:

NP b,z,t is the aggregated position of BRP b for settlement period t in zone z, which is calculated using the formula:

$$NP_{b,z,t} = \sum_{m \in b} TPSS_{mp,z,t} + \sum_{p \in b} TPSB_{mp,z,t}$$

Where

TPSSmp,z,t is the total amount (positive value) of sold electricity by market participant mp belonging to BRP b, for each settlement period t in zone z according to contracted sales volumes on DA market, and/or Real-Time Market (RTM), and/or ID market;

TPSBmp,z,t is the total amount (negative value) of purchased electricity by market participant mp belonging to BRP b, for each settlement period t in zone z according to contracted purchase volumes on bilateral agreements and/or DA and/or ID markets;

MPb,z,t is the measured position of BRP b for settlement period t in zone z, which is calculated using the formula:

$$MP_{b,z,t} = \sum_{u \in b} MDQ_{u,z,t} + \sum_{p \in b} MOQ_{p,z,t}$$

Where

MDQu,z,t – the certified metered data of off-take (positive value) units u belonging to the balancing group of BRP, for settlement period t in zone z;

MOQp,z,t – the certified metered data of load representative p, which is part of the balancing group of BRP, for settlement period t in zone z (negative value).

Price for activation of balancing energy:

The price of balancing electricity is defined as the weighted average price for the calculation period 't' in each trading zone 'z':

- Price for upward balancing energy:

$$MSP^{up}_{z.t} = \left| \frac{\sum_{rtu \in t} \left(\sum_{e \in z} \left(ABE^{up}_{e.z.rtu} \right) \cdot MSP^{up}_{z.rtu} \right)}{\sum_{rtu \in t} \left(\sum_{e \in z} \left(ABE^{up}_{e.z.rtu} \right) \right)} \right|$$

- Price for downward balancing energy:

$$MSP_{z.t}^{dn} = \left| \frac{\sum_{rtu \in t}(\sum_{e \in z}(ABE_{e.z.rtu}^{dn}) \cdot MSP_{z.rtu}^{dn})}{\sum_{rtu \in t}(\sum_{e \in z}(ABE_{e.z.rtu}^{dn}))} \right|$$

Where:

$ABE_{e.z.rtu}^{up}$ *and* $ABE_{e.z.rtu}^{dn}$ *are activated upward and downward balancing energy from the plant that provides balancing services 'e' in the zone 'z' for the RTU (unit of real-time - 15 minutes);*

$MSP_{z.rtu}^{up}$ *and* $MSP_{z.rtu}^{dn}$ *– marginal prices of upward/ downward balancing energy for each RTU.*

The marginal prices for activation of balancing energy based on the RTU are defined as:

1) the highest bid price for upward balancing energy, which is activated in the case of a deficit in the system;
2) the lowest offer price for downward balancing energy, which is activated if there is a surplus in the system;
3) if the system is balanced, the marginal price of the balancing energy of this RTU is calculated on the basis of the DA market price determined by the result of the auctions for this settlement period, or in the event that the DA market auctions for this settlement period did not take place – based on the weighted average DA market price for the previous 30 days. The upper limit for the price of balancing energy is set to 115% of the DA market price by NEURC Resolution No. 516 of February 28, 2020. After the introduction of martial law in Ukraine, the upper limit for the price of balancing energy is set to 120% of the price of DA market for the relevant billing period.

Imbalance price calculation

The imbalance charge for BRP 'b' in all zones 'z' during the calculation period 't' is determined by the formula:

$$CIEQ_{b.z.t} = \begin{cases} IEQ_{b.z.t} \cdot min\left(PDAM_{z.t}, IMSP_{z,t}\right) \cdot (1 - k^{im}), \text{if } IEQ_{b.z.t} > 0 \\ IEQ_{b.z.t} \cdot max\left(PDAM_{z.t}, IMSP_{z,t}\right) \cdot (1 + k^{im}), \text{if } IEQ_{b.z.t} < 0, \end{cases}$$

Where:

$IEQ_{b.z.t}$ *is an imbalance of BRP 'b' for the settlement period 't' in zone 'z';*

$PDAM_{z.t}$ *is the DA market electricity price in zone 'z' for the calculation period 't';*

$IMSP_{z,t}$ *is the imbalance price for the accounting period 't' in zone 'z', which corresponds to the marginal price of balancing energy for the accounting period 't' and is determined depending on whether the system is in deficit, surplus, or balanced;*

$k^{im} = 0{,}05$ *is an imbalance price ratio.*

Annex III. Overview of Armenia's Wholesale Electricity Market

For launching the DA market in Armenia, the testing procedure started in February 2022 and upon completion of that procedure, the DA market in Armenia has become operational since February 2023. According to the wholesale electricity market trading rules, approved by the PSRC's Resolution №516-N on December 25, 2019 (hereinafter: Trading Rules), the wholesale electricity market has the following segments: Direct Contracts, DA market and the balancing market.

The Market Operator organizes the regular work of the DA market, including the DA market clearing through the market management program. The market operator is also responsible for operating and maintaining the program. In the DA market, the gate opening time is 10:29 on the D-1, and the gate closure time is 12:59 of the same day. The trading period is 60 minutes.

The prices of offers submitted by wholesale electricity market participants may not exceed the maximum price of the BSP set by the Commission or have a negative value. In the case of a Guaranteed Supplier, the prices of the bids for sale and purchase cannot be lower than one hundred forty percent of the minimum price of the BSP and exceed the maximum price of the BSP set by the Commission. For generators subject to tariff regulation (except BSP and others), sales bids cannot exceed 140% of the electric energy tariff set by the Commission for the given plant (one hundred forty percent of the tariff in case of exceeding the maximum price of the BSP, the maximum price of the BSP) or be lower than that tariff. Such bids are rejected by the Market Operator.

In the case of electricity import or export, the market participant shall provide information to the System Operator and the Market Operator regarding the volumes of intended import and/or export on an hourly basis. The information is sent via a market management program and must include the relevant import/export agreement. The market participant is obliged to submit the above information no later than one working day after the conclusion of the relevant agreement, and in the case, the transaction involves trading in the DA market, by 16:59 D-1 inclusive. These deadlines are not applied if the agreement for import and/or export is concluded in the Direct Contracts Market.

Currently, procurement of the balancing services is not market-based; hence there are no prequalification procedures for BSPs. The gas-fired combined cycle power plant (Yerevan CCGT-1) of "Yerevan Thermal Power Center" CJSC has the obligation to provide balancing services. The minimum tariff of BSP to the electricity system by Yerevan CCGT-1 is 15,138 Armenian dram per KWh (without VAT) and the maximum tariff - 30,517 Armenian dram per KWh (without VAT). The tariffs for providing balancing services are formed from Electricity System regulated minimum purchasing tariffs and maximum selling tariffs.

Small HPP`s (Installed capacity up to 30 MW) and RES producers have the balancing responsibility according to PPA signed with Universal (Guaranteed) supplier.

Electricity producers involved in State-Private Partnership transactions, Small HPPs (with up to 30 MW installed capacity), and other electricity producers utilizing renewable energy sources, whose electricity

purchase guarantee, as per energy law, has not expired, bear the balancing responsibility according to the Power Purchase Agreement (PPA) signed with the Universal (Guaranteed) supplier. The exemplary form of the agreement is approved by the PSRC's Resolution №456-N of December 12, 2018 (for plants with installed capacity up to 30 MW) and Resolution №543-N of December 13, 2017 (for plants with installed capacity exceeding 30 MW). The agreement shall be signed for the entire electricity purchase guarantee term prescribed by the Law on Energy or State-Private Partnership transaction.

Annex IV. Legal acts and relevant links

Contracting Party	Market	Legal Acts and relevant links
Albania	DACA	Rules And Contracts – Operatori i Sistemit Te Transmetimit (ost.al)
	IDCA	Rules And Contracts – Operatori i Sistemit Te Transmetimit (ost.al)
	BAM	Law no.43/2015 "On energy sector", amended with law no. 7/2018 "For some amendments on Law nr. 43/2015 "On energy sector" "Market Model", Decision of Council of Ministers no. 519, date, 13.7.2016, amended by Decision of Council of Ministers No. 872 date 27.12.2022. "Albanian Balancing Market Rules" ERE Decision no. 106/2020, date2.7.2020. Legislation – Operatori i Sistemit Te Transmetimit (ost.al)
Armenia		The law on energy of the Republic of Armenia https://www.arlis.am/DocumentView.aspx?docid=174041 The wholesale electricity market trading rules, approved by the Public Services Regulatory Commission's Resolution №516-N of December 25, 2019, https://www.arlis.am/DocumentView.aspx?DocID=185428 Electricity market transmission network code, approved by the Public Services Regulatory Commission's Resolution №522-N of December 25, 2019 https://www.arlis.am/DocumentView.aspx?DocID=184903
Bosnia and Herzegovina	DACA	Daily auction rules on the borders BIH – Montenegro and BIH – Croatia (carried out by Auction Office for South East Europe – SEE CAO) Daily auction rules on the border Bosnia and Herzegovina – Serbia (local language)
	IDCA	Intraday auction rules on the border Bosnia and Herzegovina – Montenegro (local language) Intraday auction rules on the border Bosnia and Herzegovina – Croatia Intraday auction rules on the border Bosnia and Herzegovina – Serbia (local language)
	BAM	Law on Transmission of Electric Power, Regulator and System Operator of Bosnia and Herzegovina and Law Establishing an Independent System Operator for the Transmission System of Bosnia and Herzegovina provide the legal basis for regulating the balancing of electricity. On the basis of these laws, by-laws were drafted that regulate this area in more detail, such as: - Tariff methodology - Market rules - Network code - A set of documents that more closely define the balance market and the procurement of ancillary services
Kosovo*	DACA	https://www.seecao.com/
	IDCA	https://www.kostt.com/MO/
	BAM	Grid Code and Market Rules
Georgia	DACA	N/A
	IDCA	N/A
	BAM	The Law on Energy and Water Supply sets the general aspects for balancing. Annex 2 of the "Electricity Market Rules" approved by the resolution N46, August 11, 2020, of the GNERC provides the detailed requirements and procedures for the registration of the balancing responsible parties and BSPs, balancing product procurement procedures, as well as settlement procedures, etc. https://www.matsne.gov.ge/ka/document/view/4747785?publication=8 Law on Energy and Water Supply https://www.matsne.gov.ge/ka/document/view/4966631?publication=8 Electricity Market Rules
Moldova	DACA	https://www.moldelectrica.md/files/docs/market/Reguli_alocare_termen_lung_MD-RO.pdf
	IDCA	N/A

	BAM	Provisions regarding the balancing responsibility are provided within Law nr. 107 on electricity, and also within the Wholesale Electricity Market Rules (WEMR). Within the WEMR are defined the rules related to imbalance settlement of the BRPs (prices for imbalances), invoicing, etc. Law nr. 107 on electricity https://www.legis.md/cautare/getResults?doc_id=135004&lang=ro# WEMR https://www.legis.md/cautare/getResults?doc_id=138000&lang=ro#
Montenegro	DACA	(ME-AL, ME-BA, ME-XK*) Rules for explicit Daily Capacity Allocation on Bidding Zone borders serviced by SEE CAO: https://www.seecao.com/sites/default/files/documents/document/2_SEE%20CAO_Daily%20Allocation%20Rules.pdf (ME-IT) Rules for Daily Capacity Allocation on Italy-Montenegro Border: https://www.seecao.com/sites/default/files/documents/document/Rules%20for%20Daily%20Capacity%20Allocation%20on%20IT-ME%20Border.pdf (ME-RS) Rules for Daily Capacity Allocation on borders between bidding zones of EMS and CGES: https://www.cges.me/images/Pravila_za_dnevne_aukcije_ME-RS_za_2023.pdf
	IDCA	(ME-AL) Rules for ID Capacity Allocation on borders between control areas of CGES and OST: https://www.cges.me/images/fajlovi/Pravila_Alokacija_kapaciteta/CGES_-_OST_Pravila_za_unutardnevnu_dodjelu.pdf (ME-BA) Rules for ID Capacity Allocation on borders between control areas of ISO BiH and CGES: https://www.nosbih.ba/files/2019/11/20191118-bs-Pravila-za-unutardnevnu-dodjelu-kapaciteta-BiH-CG.pdf (ME-XK*) Rules for ID Capacity Allocation on borders between control areas of CGES and KOSTT: https://www.cges.me/images/fajlovi/Pravila_Alokacija_kapaciteta/CGES_-_KOSTT_Rules_for_intraday_allocation_2021.pdf (ME-RS) Rules for ID Capacity Allocation on borders between bidding areas of EMS and CGES: https://www.cges.me/images/Pravila_za_unutardnevnu_raspodjelu_kapaciteta_ME-RS_za_2023.pdf
	BAM	The general framework for system balancing is set out in the Energy Law of Montenegro. In addition: • the Rules on the transmission system operation further define the technical aspects regarding the system balancing, • the Methodology for setting prices, terms, and conditions for the provision of ancillary and balancing services to the transmission system operator defines the main principles regarding the procurement of active power reserves and balancing energy, • the Rules on the functioning of the balancing market prescribe market-based procurement of the balancing energy (however, these rules do not apply until a centralized balancing platform is established), and The Market Rules prescribe the operation of the balancing mechanism regarding imbalance settlement.
North Macedonia	DACA	https://aukcijaatc.mepso.com.mk/PublicPage/AuctionRules.aspx
	IDCA	N/A
	BAM	The legal base for electricity balancing is in the Energy law. The Rules for balancing of the power system are adopted by the TSO after the approval of ERC. Dimensioning of the balancing reserves is in the Electricity transmission Grid Code.
Serbia	DACA	https://ems.rs/en/allocation-of-available-transfer-capacities-2/
	IDCA	https://ems.rs/en/allocation-of-available-transfer-capacities-2/
	BAM	The legal framework is established through the Energy Law and Market code.
Ukraine	DACA	For UA – PL, UA – SK, UA-HU borders: https://ua.energy/wp-content/uploads/2023/10/Dobovi-pravyla-JAO-UA-ENG-new-29.08.2023_.pdf For UA – RO border: https://ua.energy/wp-content/uploads/2023/09/2.-Pravyla-dobovogo-rozpodilu-UA_RO-eng-ukr.pdf For UA – MD border: https://ua.energy/wp-content/uploads/2024/02/Pravyla-dobovogo-rozpodilu.docx
	IDCA	N/A
	BAM	The main legal framework for electricity balancing includes:

		• Law of Ukraine "On the Electricity Market": This law provided the overall legal framework for the functioning of the electricity market in Ukraine, including provisions related to electricity balancing (https://zakon.rada.gov.ua/laws/show/2019-19#Text) • Market rules (NEURC resolution 14.03.2018 № 307) (https://zakon.rada.gov.ua/laws/show/v0307874-18#Text) At the moment, the balancing mechanism is implemented based on the balancing market (energy product) and the ancillary services market (capacity product, which represents frequency support reserves, frequency restoration, and replacement reserves). According to the Law: The balancing market of electricity (hereinafter referred to as the balancing market) is a market organized by the transmission system operator with the aim of ensuring sufficient volumes of electrical power and energy necessary for the real-time balancing of production and import volumes of electricity, consumption and export of electricity, regulation of system constraints in the unified energy system of Ukraine, as well as financial settlement of electricity imbalances. The ancillary services market (hereinafter referred to as the AS market) is a system of relations arising in connection with the procurement of ancillary services by the transmission system operator from ancillary service providers. Ancillary services are services defined by this Law and market rules that the transmission system operator procures from ancillary service providers to ensure the stable and reliable operation of the unified energy system of Ukraine and the quality of electrical energy in accordance with established requirements.