Analysis of the Potential to Provide Cross-Border Balancing Services and Energy in the Black Sea Region

A Joint Study of the Black Sea Regional Transmission Planning Project (BSTP) and Black Sea Regulatory Initiative (BSRI)

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Black Sea Transmission Planning Project (BSTP)
and
Black Sea Regulatory Initiative (BSRI):

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Prepared for:

United States Agency for International Development
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ABBREVIATIONS

General

TSO - Transmission System Operator
UCTE - Union for the Coordination of Transmission of Electricity
ENTSO/E - European Network of Transmission System Operators for Electricity (former UCTE)
ACER - Agency for the Cooperation of Energy Regulators
REM - Regional Energy Market
SEE - South East European
BSTP - Black Sea Transmission Project
BSRI - Black Sea Regulatory Initiative
USEA - United States Energy Association
NARUC - National Association of Regulatory Utility Commissioners
PSS/E - Power System Simulator for Engineering
GTMAx - Generation and Transmission Maximization Model
OPF - Optimal power flow
IPS/UPS - Interregional Power System/Unified Power System

Transmission

AC - Alternating Current
DC - Direct Current
HV - High Voltage
MV - Medium Voltage
LV - Low Voltage
HVAC - High Voltage AC
HVDC - High Voltage DC
NTC - Net Transfer Capacity
TTC - Total Transfer Capacity

Generation

HPP - Hydro Power Plant
PHPP - Pumping Hydro Power Plant
TPP - Thermal Power Plant
NPP - Nuclear Power Plant
CCGT - Combined cycle gas turbine
CHP - Combined Heat and Power Generation
RES - Renewable Energy Sources
MOR - Maintenance Outage Rate
FOR - Forced Outage Rate

Balancing Market

EB - Electricity Balancing
BS - Balancing Services
LFCR - Load-Frequency Control
PC - Primary Control
SC - Secondary Control
TC - Tertiary Control Area Control Error (ACE)
AGC - Automatic Generation Control
ACE - Area Control Error

BRP	- Balance Responsible Parties
BSP	- Balancing Service Providers
FCR	- Frequency Containment Reserve
FRR	- Frequency Restoration Reserve
NC	- Network Code
aFRR	- Automatic Frequency Restoration Reserve or Secondary Regulation Reserve
mFRR	- Manual Frequency Restoration Reserve or fast Tertiary Regulation Reserve
RR	- Restoration Reserve or slow Tertiary Regulation Reserve
CMO	- Common Merit Order
IGCC	- International Grid Control Cooperation
CoBA	- Coordinated Balancing Area
FAT	- Full Activation Time
CZC	- Cross Zonal Capacity
FG EB	- Framework Guidelines Electricity Balancing

Countries

	ISO	Country	Car
Bulgaria	BG	BUL	BG
Romania	RO	ROM	ROM
Turkey	TR	TUR	TUR
Ukraine	UA	UKR	UKR
Armenia	AM	ARM	ARM
Georgia	GE	GEO	GEO
Moldova	MD	MLD	MLD
Russia	RU	RUS	RUS
Azerbaijan	AZ	AZB	AZB
Belorussia	BY	BLR	BLR
Iran	IR	IRN	IRN
United Kingdom	UK	UK	UK

1 INTRODUCTION

Consistent with United States Agency for International Development's (USAID) medium term development assistance objectives for the Black Sea region, the objective of this study is to strengthen the capacity of Transmission System Operators (TSOs) and regulators in the Black Sea region to fully understand the current systems for balancing national networks, to enable their understanding of potential cross-border, cost based and market based mechanisms for the provision of balancing services, and determine the framework for further cross-border balancing cooperation.[1] Recent developments in the Black Sea region's transmission networks include the commissioning of increased quantities of intermittent renewable energy generation and several proposals for new synchronous and asynchronous interconnections between members of the Black Sea countries. These developments are driving interests among of the countries in optimizing balancing reserves and energy on a sub-regional basis.

The study is performed jointly by the US Energy Association (USEA) and the National Association of Regulatory Commissioners (NARUC). It encompasses a year-long effort to explore the value proposition of cross-border sharing of reserves and other ancillary and balancing services, as well as to ascertain regulatory and policy milestones necessary to unlock and capitalize upon integrated balancing markets at the sub-regional and regional level in the Black Sea region. By utilizing production cost optimization modeling, the study examines both transitional (i.e., "cost-based") and fully integrated market balancing mechanisms while also analyzing a sub-set[2] of the Black Sea countries' readiness to engage in integrated markets.

The results of this study estimated the net benefits of three specific market integration mechanisms – i.e., imbalance netting, common dimensioning and reserve sharing as well as common merit order dispatch. At a sub-regional level, these results were corroborated through a sensitivity analysis using cost-based pricing provided through the BSRI countries. These study results are paired with an evaluation of regulatory and policy framework characteristics that are imperative for effective implementation of regionally integrated balancing markets, providing specific recommendations that TSOs and regulators can use to develop and engage in next steps.

The chapters include the following information:

Chapter Two of the study summarizes the policy and regulatory requirements of the European Union (EU) Directives for the effective provision of cross-border balancing services and evaluates the current status of each country in terms of the following characteristics:

- Unbundling of the Transmission System Operator
- Transparency of Network Data
- Regulatory Authority over the Transmission System Operator
- Congestion Management on Interconnections
- Real Time Balancing Ancillary Services
- Market Design
- Renewable Energy Integration

This chapter notes that while there is significant momentum toward the development of cross-border energy and balancing markets in the region, a cost based transitional approach may be effective in encouraging optimization of balancing reserves and energy.

[1] The study is co-authored by the BSTP Project of USAID and the US Energy Association as well as the Black Sea Regulatory Initiative (BSRI) of USAID and the National Association of Regulatory Commissioners (NARUC).

[2] The BSRI consists of four out of seven of the countries of the BSTP countries. Therefore, Bulgaria, Romania and Turkey were excluded from the regulatory examination.

Chapter Three builds on the findings contained in the BSTP Phase One report on the Potential for Cross-Border Provision of Balancing Services in the Black Sea region and provides a methodology for assessing the benefits of the cross border provision of balancing services customized to the Black Sea region.

Chapter Four reviews the input data and assumptions used to calculate the benefits of cross-border balancing services from the cost and market based approaches.

Chapter Five evaluates the direct and indirect benefits of the cross-border provision of system balancing services for each methodology under a market based trading system and provides a sensitivity analysis of the direct benefits using a cost-based methodology. Recognizing that the region may require an interim step in its progress toward fully competitive balancing markets, the BSRI recommended that the BSTP Working Group conduct a cost-based sensitivity analysis of the benefits deriving from its market based calculations. Using data provided by BSRI on the cost of balancing services in each country, the BSTP conducted a sensitivity analysis of its market based calculations that provide indications of the benefits of the cross border provision of balancing services in a cost regulated environment.

Chapters Six and Seven provide conclusions and recommendations for next steps from the BSTP (Chapter 6) and BSRI (Chapter 7).

Common Terminology

Through this joint exercise, it was discovered that BSRI regulators and BSTP TSOs use two different terminologies for balancing services, which created confusion among the working group members. The terminology utilized by ENTSO-E is presented in the table below. The terminology formerly used by ENTSO-E referred to balancing reserves primarily in terms of control philosophy. Local and centralized activation of spinning reserves were called primary and secondary control, respectively. Activation of non-spinning reserves were called tertiary control. Secondary reserves are activated either automatically through an Automatic Generation Control (AGC) system installed at a dispatch center, or through the orders given by the dispatchers manually. There was no differentiation between automatic and manual activation of the secondary reserves in the former terminology. In the latter terminology, both secondary and tertiary reserves, which are centrally activated, are identified as frequency replacement reserves (FRR). However, depending on the activation of the replacement reserve, it is either called as aFRR, if automatically activated through an AGC system, or mFRR, if manually activated.

Please note: Both terminologies are used interchangeably in this Report.

Terminology 1 (Former ENTSO-E terminology)	Terminology 2 Latter ENTSO-E terminology)	Details
Primary reserve	**FCR** (Frequency Containment Reserve)	**Local** **automatic** and **continuous** activation of **spinning** reserves by speed governors of the power plant units.
Secondary reserve	**aFRR** (Frequency Restoration Reserve – automatic)	**Centralized** **automatic** and **continuous** activation of **spinning** reserves by dispatch center to restore primary reserve (FCR).
Secondary reserve	**mFRR** (Frequency Restoration Reserve – manuel)	**Centralized** and **manual** activation of **spinning** reserves by dispatch center to restore primary reserve (FCR).
Tertiary reserve	**mFRR** (Frequency Restoration Reserve – manual)	**Centralized** **manual** activation of **non-spinning** reserves to restore primary (FCR) and secondary reserve (both aFRR and mFRR)

Table 1.1 Former and Latter Balancing Service Terminology Utilized by ENTSO/E

2 BSRI POLICY AND REGULATORY GAPS AND RECOMMENDATIONS

Background

This section identifies the key policy and regulatory gaps, recommended policy measures, and milestones for balancing integration in the BSRI countries (Armenia, Georgia, Moldova and Ukraine) at the national and sub-regional level. As members in and observers to the Energy Community, BSRI countries are beginning to design wholesale electricity markets and to develop market rules for internal and external trade. In this environment, the BSRI members will require a gradual transition to a market based system of balancing and ancillary services to overcome the policy and regulatory gaps identified in this chapter.

The policy and regulatory gaps are defined and considered at the national and sub-regional level, based on the following:

- The BSTP/BSRI region includes three synchronous zones that make integration of balancing market more complex than in the ENTSO-E community. The BSTP member states are members of the following synchronous zones:
    - Armenia is in parallel work with the Iranian transmission network
    - Bulgaria, Romania and Turkey are members of Union Coordination for the Transmission of Electricity (UCTE) synchronous zone
    - Georgia, Moldova and Ukraine are members of the Integrated Power System/Unified Power System (IPS/UPS) synchronous zone
- Georgia and Moldova/Ukraine are in the same synchronous zone but are not directly connected to one another.
- At the current status of the balancing markets among BSTP member states, a high level of diversification in implemented balancing principles and the development of balancing markets is present. The characteristics of each national power system, different initial balancing market designs and different initial wholesale market conditions present major obstacles in regional balancing integration and significantly affect the results of a quantitative assessment of balancing market integration.

Although there are three separate synchronous zones, many of these countries are developing direct current (DC) interconnections that will lead to the development of an energy bridge between the synchronous zones and enable sharing of balancing capacity.

However, given that the technical and commercial potentials are influenced by the systems' participation in different synchronous zones and the present or future alternating current (AC) and DC connections, the potential for balancing cross-border cooperation among BSTP member states as well as the policy and regulatory barriers against the realization of benefits should be recognized and assessed at the following sub-regional levels[3]:

- **Sub-region A1**: Armenia and Georgia
- **Sub-region C:** Moldova and Ukraine

[3] Inception Report: Analysis of the Potential to Provide Cross-Border Balancing Services and Energy in the Black Sea Region, Black Sea Regional Transmission Planning Project (BSTP) Sub-Agreement: USEA/USAID – 2017 – 708 – 01, 2017.

In response, key policy and regulatory gaps are assessed at the national and sub-regional level. Experiences from EU countries, in particular those on transitional steps, are also considered in the recommendations.

2.1 National Policy and Regulatory Gaps: Scope of the Study

In the scope of the study, a regulatory questionnaire was developed to identify key policy and regulatory gaps and shared with the National Regulatory Authorities (NRA) of Armenia, Georgia, Moldova, and Ukraine. The aim of the policy and regulatory data collection was to identify and prioritize regulatory gaps and to explore the policy steps and goals necessary to capitalize on the benefits of sharing reserves and integrating a balancing market at the regional and sub-regional level. There is a growing understanding among TSOs and regulators with regard to the benefit to sharing of balancing reserves and how this will enhance the region's reliable distribution of electricity.

The questionnaire clustered questions in key policy and regulatory subjects, which were mainly drawn from the BSRI Wholesale Market Guidelines[4], legislative acts of the Third Energy Package[5], and references from the Agency for the Cooperation of Energy Regulators (ACER)[6], as indicated in Figure 2.1.

Figure 2.1 Clustering of the questions in terms of key policy and regulatory subjects

Codes of the Study

In an effort to synthesize the responses from NRAs, the conclusions were color coded. This approach enabled the comparison of the countries in terms of their gaps in policy/regulatory key subjects.

The explanation of each color is as follows[7]:

- Green: corresponds to "yes" in terms of both law / regulatory framework and practice.

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[4] BSRI Wholesale Market Guidelines for Black Sea Electricity Market Integration, Dec. 2016 (by USAID and NARUC under BSRI).

[5] The legislative acts of the Third Energy Package:

- Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (the Electricity Directive)
- Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 (Regulation No. 714)

[6] ACER references:

- http://www.acer.europa.eu/en/electricity/FG_and_network_codes/Pages/Balancing.asp
- ACER, "Framework Guidelines on System Operation," (2014).
- "Initial Impact Assessment for the Framework Guidelines on Electricity Balancing," ACER, September 18, 2012.

[7] *Please Note*: The answers to the questions from NRAs are based on the legal and regulatory framework as of March 2018.

- Yellow: corresponds to "yes" in terms of law / regulatory framework (or relevant law/legislations are under progress) but no practice has been implemented.

- Red: corresponds to "no" in terms of both law / regulatory framework and practical implementations.

Color code	Answer of the question	
	In terms of law / regulatory framework	In terms of practical implementations
	Yes	Yes
	Yes (or under progress)	No
	No	No

Table 2.1 Explanations of the colour codes in the questionnaire - based on implementations as of March 2018

Answers to the questions are detailed in the following sub-sections. Section 2.2 summarizes the national and sub-regional policy/regulatory gaps deduced from the answers.

2.1.1 Unbundling

One of the fundamental aspects of the EU Directives is an unbundled TSO that is regulated by the national regulator to ensure third-party access. As Directive EC 72/2009[8] states, any system for unbundling should be effective in removing any conflict of interests between producers, suppliers, and transmission system operators that creates incentives for the necessary investments and guarantees the access of new market entrants.

Table 2.2 captures the responses of the NRAs. The conclusion from the responses demonstrated that generation and transmission segments of the power sector are unbundled, a market operator (MO) is defined (not yet in Moldova[9]), and the NRA is independent from the government in law. The questions were aimed at addressing the level of unbundling in each BSRI country as well as independence of the NRA from the government.

Unbundling						
		Subregion A1		Subregion C		
No	Key Topic	AM	GE	MD	UA	Comments
1	Are the Transmission & Generation unbundled?					
2	Are the TSO & Market operator unbundled?					**MD:** YES by law. However, not in practice yet (functioning through TSO currently).
3	Is the NRA independent from the government?					

Table 2.2 Questionnaire Results (Unbundling) – based on implementations as of March 2018

[8] Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (the Electricity Directive)

[9] Currently, in Moldova, the MO and TSO are not unbundled by law but rather the TSO is operating both systems.

Main Observations and Recommendations

Although all countries have defined laws, there are some concerns with unbundling in practice. Though responsibilities are delegated to MOs, TSOs still have an important role in operating the market in Armenia, Georgia, and Ukraine. This is particularly true in BSRI countries in which balancing services are provided through long-term bilateral contracts rather than through procurement using a competitive market, due to the lack of capacity in competitive balancing service providers. Given the lack of a competitive balancing market, balancing services required in those countries are ensured by predefined power plants based on long-term bilateral contracts. The main concern in such countries is monitoring of the provision of balancing services provided by the responsible power plants. Therefore, the role of TSO is more prevailing at the initial phase of market development.

This was the case in Turkey in which market operation began to be performed by a directorate within the transmission company, TEIAS. Market operation had been performed by a directorate within TEIAS at the initial phase of a competitive market development when long-term bilateral contracts were dominant in the market. However, along with the development of the competitive market, the market operation was completely unbundled from transmission operation in 2013 by the formation of an independent MO; Energy Exchange Istanbul (EXIST). In BSRI countries, a similar process can be considered for the practical unbundling of market and network operations in the long-term. That is, market operation should be unbundled from system operation practically, along with development of a competitive market gradually.

2.1.2 Open Access

Open access transmission is the ability of resources to gain access to the transmission network to serve load or to transit the system in a non-discriminatory fashion. As recommended by the BSRI Wholesale Market Guidelines (BSRI Guideline), NRAs are encouraged to establish non-discriminatory and transparent tariffs for access to national transmission networks, and, where not yet done, establish unbundled transmission tariffs.

The questions were modeled using the recommendation from the BSRI Guidelines. The key requirements and observations are provided in Table 2.3.

Open Access						
		Subregion A1		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
4	Are the Third Party Access Rights to T&D established in Law?					
5	Are the Third Party Access tariffs/charges non-discriminatory?					
6	Is the methodology defined for allocation of transmission costs?					
7	Are the Third Party Access tariffs/charges based on cost reflective approaches?					
8	Are the Third Party Access tariffs/charges made public?					
9	Are the network codes minimally harmonized with neighboring countries?					**MD, UA:** Under progress
10	Does the TSO coordinate capacity <u>calculation</u> with neighboring TSOs?					
11	TSO coordinates capacity <u>allocation</u> with neighboring TSOs?					**AM:** Currently only isolated connection with GE (No NTC approach yet) **MD:** Under progress
12	Is the grid code published?					**MD, UA:** Under progress

Table 2.3 Questionnaire Results (Open Access) - based on implementations as of March 2018

Main Observations and Recommendations

There are significant developments in terms of open access in all countries. However, the following should be considered:

- Currently, the interconnections between Armenia and Georgia are through passive islands.[10] Therefore, allocation of capacity does not make sense in passive island connections. However, after the completion of the HVDC B2B interconnection between Armenia and Georgia, allocation of its capacity to interested market players should be considered. Georgia has developed an electronic auction mechanism (GCAT) for allocating Net Transfer Capacity (NTC) among the interested market players. GCAT is being utilized for the HVDC B2B interconnection lines between Georgia and Turkey. (A similar electronic auction platform is also utilized in Turkey.) As a midterm recommendation, such a capacity allocation mechanism should also be considered in Armenia when the HVDC B2B substation is in service.

- In Moldova and Ukraine, network codes are being developed in line with EU legislation. However, they have not been adopted. This process should continue to guarantee that network codes of Moldova and Ukraine are harmonized along with the definitions of balancing services and qualification/ certification of providers are aligned. Grid codes of both Ukraine and Moldova should be approved and published by the corresponding regulators. In Moldova, a methodology should be defined and published by the regulator for allocation of transmission costs. This needs collaboration between the TSO and the regulator. Third party access tariffs/charges should be calculated by this methodology and approved by the regulator. A capacity allocation mechanism should also be considered in Moldova, like the one in Ukraine.

2.1.3 Data Transparency

Data transparency is accomplished by publishing relevant data that eliminates information asymmetries and provides all market participants critical market information. It is an important component of successful market integration. According to the EU Directives[11], general categories of data need to be organized as follows: (1) system operating conditions (load, generation, imports, and exports); (2) cross-border capacity forecast and actual usage; (3) system investments and planning processes; and (4) balancing (costs, suppliers, and methods of choosing the supplier if not market-based).

In order to foster data transparency, TSOs should implement coordination and information exchange mechanisms to ensure the security of the networks in the context of congestion management. The information published should include a general scheme for the calculation of the total transfer capacity (TTC), the transmission reliability margin (TRM), and Net Transfer Capacity (NTC) based upon the electrical and physical features of the network. In addition, the safety, operational and planning standards used by transmission system operators should be made public.

[10] In this implementation, some parts of the grid in one country (close to border with the other country) isare completely isolated from its original grid and connected to the other country. If the isolated grid does not include any generator it is called as passive island.

[11] Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (the Electricity Directive)

Data Transparency						
		Subregion A I		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
13	Is the information on system operating conditions (load, generation, import, export) published by TSO?					
14	Are the safety, operational and planning standards used by TSO made public?					**AM, UA:** Partially
15	Are the cross-border capacity forecast (ATC & NTC) and actual usage made public?					**AM:** Currently only isolated connection (No NTC approach yet)
16	Are the NTCs auctioned monthly/yearly?					**AM:** Currently only isolated connection (No NTC approach yet) **MD:** Bilateral procedure with UA
17	Are the NTC auction results and prices are published as soon as practicable by the TSOs?					**AM:** Currently only isolated connection (No NTC approach yet) **MD:** Bilateral procedure with UA
18	Are the system planning process and investments made public?					**UA:** Under progress
19	Is the method of choosing balancing supplier made public?					**AM, GE:** Managed by TSO currently - no public rules **UA:** Complex methodology currently

Table 2.4 Questionnaire Results (Transparency) - based on implementations as of March 2018

Main Observations and Recommendations

As illustrated in Table 2.4, transparency is among the key subjects which needs significant improvement at the region level (particularly in Armenia, Moldova, and Ukraine). Georgia has already started NTC based market coupling with Turkey and this essentially contributed to the data transparency. Although TSO data, market data, and information regarding NTC calculations are available upon request, they are not published (e.g., on the web).

Currently, TSOs choose balancing service suppliers in all four countries. However, the mechanism for qualifying the balancing responsible parties (BRP) is not transparent. NRAs and TSOs need to discuss requirements from BRPs. In addition, the methodology for qualifying BRPs and technical requirements from the BRPs should be approved by the NRAs and described in public documents. This will essentially signal to investors that this process is open and competitive.

2.1.4 Regulatory Authority over the TSO

Separating the TSO from the operation of wholesale generation suppliers is a critical step in preventing vertical market power. In addition, the regulator should have regulatory authority over all key aspects of the TSO's operations and planning. A key component of the EU Directives[12] is the creation of an independent regulator. The reforms require that each member state designate a single NRA that is independent from the government and any private entities. Article 37 of the EU Directives[8] enumerates the duties and powers given to the NRA. Questions and answers of the NRAs regarding regulatory authority over the TSO are presented in Table 2.5.

[12] Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (the Electricity Directive).

Regulatory authority over TSO						
		Subregion A1		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
21	Does the NRA have authority to monitor cross-border activity including access to models TSO uses to calculate cross-border transmission capacity?					**All:** Authority of NRAs in law. However, not in practice yet.
22	Does the NRA approve the Grid Code?					
23	Is the investment planning process of TSO approved by National Regulatory Agency (NRA)?					
24	Are the Third Party Access tariffs/charges and their methodologies approved by the Regulator?					**MD:** Improvement in progress
25	Are performance of network security and reliability monitored by the regulator?					**All:** No methodological (KPI based) monitoring yet (under progress)
26	Are the levels and effectiveness of market opening and competition monitored by the NRA?					**AM, MD, UA:** Authority of NRAs in law. However, not in practice yet.
27	Does the NRA approve Market Rules?					
28	Does the NRA receive prices and volumes of wholesale trades?					
29	Are the average wholesale prices published at least daily?					**All:** Currently only monthly.
30	Does the NRA have the authority by law/legislation/etc. to monitor implementation of rules relating to the roles and responsibilities of TSO and other market players?					
31	Is the NRA monitoring the implementation of rules relating to the roles and responsibilities of TSO and other market players?					**AM, UA:** Under progress
32	Is the NRA monitoring investments in generation capacities in relation to security of supply?					**MD:** Lack of secure generation capacity

Table 2.5 Questionnaire Results (Regulatory Authority over the TSO) - based on implementations as of March 2018

Main Observations and Recommendations

- Regulatory authority over the TSO provides the most significant policy/regulatory gaps in the region. Although regulators are given some authority by law, including: approval of the grid code and market rules, and monitoring of the implementation of rules relating to the roles and responsibilities of TSOs, the regulators do not have sufficient background and/or Key Performance Index (KPI) based tools to monitor and assess the TSO activities. The TSOs are aware of this fact, and therefore, comments of the regulators to the TSO are generally not binding for the TSO to legally follow.
- The solution for NRAs is a mid-term process which necessitates capacity building and tools for the regulators to monitor TSOs. KPIs should be defined to monitor and assess the activities performed by the TSO. KPIs should be defined in primary and secondary legislations. Remedies to the data transparency gaps noted above will also contribute to closing this gap, enhancing visibility and enabling regulators to perform critical market monitoring and analysis. For example, availability of the information on system operating conditions, system planning process and investments are necessary for the regulators to assess network security and reliability.
- Currently average wholesale prices are published monthly in all countries. They should be published daily in hourly resolution, even during the market development period when wholesale prices are

determined by cost-based approaches. A methodology should be defined to calculate the hourly based wholesale prices, which will require collaboration between the NRAs and the TSOs.

2.1.5 Market Coupling

Market coupling refers to the integration of two or more electricity markets from different areas through an implicit cross-border allocation mechanism. Instead of explicitly auctioning the cross-border transmission capacities among the market participants, market coupling makes the capacities implicitly available on the power exchanges of the various areas.

Balancing reserves and energy are broadly classified as direct and indirect benefits. Market coupling for direct benefits means coordination of day-ahead schedules between one or more TSOs to schedule the most efficient combination of resources through a common merit-order (CMO). However, market coupling for indirect benefits is a long-term process as seen in EU countries. BSRI countries should initially recognize the direct benefit model, which is also recommended by the BSTP (see Section 3 for details). Sub-regional market coupling for direct benefits should be the short/mid-term goal and indirect benefits should become the long-term goal that necessitates consideration of the following main requirements:

- Cross-border transmission capacity
- Multi-stakeholder working groups at the sub-regional level to determine cross-border transmission capacity and to harmonize scheduling protocols
- Physical transmission rights: In the case of congestion on the interconnection lines, there are several possible methods to allocate physical transmission rights, including cross-border capacities, to market participants (first come, first served; pro rata; NTC-based or flow-based, bilateral or multilateral, explicit or implicit auctions)

In Europe, the target model for electricity market integration and congestion management is flow-based price coupling. Until this aim is reached, the interim NTC-based market coupling launched in several EU Member States is likely the best short-term solution in the BSRI region. Congested cross-border capacity, if any, should be allocated using an auction method (like the GCAT mechanism in Georgia).

Table 2.6 highlights the key requirements for market coupling.

Market coupling						
		Subregion A1		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
33	Is the Day-Ahead Market created in law?					**AM, GE:** On the road map **MD, UA:** Not in practice yet
34	Is the Intra-Day Market created in law?					**AM, GE:** On the road map **MD, UA:** Not in practice yet
35	Are the ATC & NTC approved by NRA?					
36	Does the NRA oversee the development of merit-order cost for all domestic resources in preparation for eventual market coupling initiatives?					**All:** Not yet.
37	Any cross border trading mechanism currently? What is it?					**AM:** Currently only isolated connection with GE (No NTC approach yet) **GE:** NTC-based explicit auctions with Turkey **MD:** NTC approach through bilateral contracts

						UA: The combination of markets based on NTC and net bandwidth
38	Are the cross-border capacity values (NTCs) bilaterally coordinated with neighbor countries?					**AM:** Calculated currently but not implemented yet (Currently only isolated connection with GE)
39	Is there a plan like: 1) NTC based market coupling; 2) NTC + day-ahead market coupling; 3) NTC + day-ahead market coupling + intra-day market coupling?					**All:** Under progress.

Table 2.6 Questionnaire Results (Market Coupling) - based on implementations as of March 2018

Main Observations and Recommendations

- In Armenia and Georgia, the creation of a day-ahead market is under progress. After creation of the day-ahead market, the regulators should monitor the development of the merit-order cost for all domestic resources in preparation for eventual market coupling initiatives.
- Currently, the regulators do not oversee the development of merit-order cost for all domestic resources. Until a competitive market develops, true-costs of balancing services (both reserve in $/MW and upward/downward activation of reserves in $/MWh) should be calculated by the regulators in collaboration with the TSOs. The NRAs should oversee the merit-order also in the market development phase when cost-based approaches are implemented in the market. Monitoring of the merit-order should be among the most critical role of the NRAs.
- In Armenia, the cross border trading mechanism with Georgia is currently based on island operation. After completion of the interconnection through the HVDC B2B substation between Armenia and Georgia, the market coupling mechanism should also cover power transactions through the HVDC. Therefore, Armenia and Georgia should start considering market coupling mechanisms for the HVDC interconnections. Georgia has already developed a market coupling mechanisms for the HVDC connection with Turkey. This experience is important for developing similar market coupling mechanisms between Armenia and Georgia.
- Moldova has already benefited from balancing energy with Ukraine. Moldova's balancing reserves are provided by the Ukrainian grid. The settlement mechanism is based on long-term balancing energy on tie-line meters. However, the development of an hourly-based day ahead market and increase in the number of competitive Balancing Service Providers (BSPs) in the sub-region will necessitate implementation of a market coupling mechanism that is compliant with EU directives.[13]
- As detailed in Section 3, imbalance netting is a balancing market coupling model that provides high benefits with low requirements for harmonization among participating TSOs. The purpose of the imbalance netting mechanism is to prevent the activation of balancing energy in automated secondary control (aFRR) in opposite directions between participating transmission system operators. This concept involves central optimization of imbalance in control areas in real time, with the aim of minimizing counter-activations of balancing energy. Imbalance netting provides the most benefits as a result of cross-border cooperation. The imbalance netting model of cross-border balancing cooperation could be the first to be implemented in the Black Sea region given its easy implementation. In addition, the EU and ENTSO-E countries are experienced in its implementation as the model has been used for more than a decade.

  Infrastructure needs of the BSRI countries should be addressed at sub-regional level to start imbalance netting as an initial step (see Figure 2.2). These include the determination of the area

[13] Directive 2009/72/EC concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (the Electricity Directive)

control error (ACE) in SCADA resolution (≈4 sec) and sub-regional communication between SCADA systems to activate optimum automatic generation control (AGC).[14]

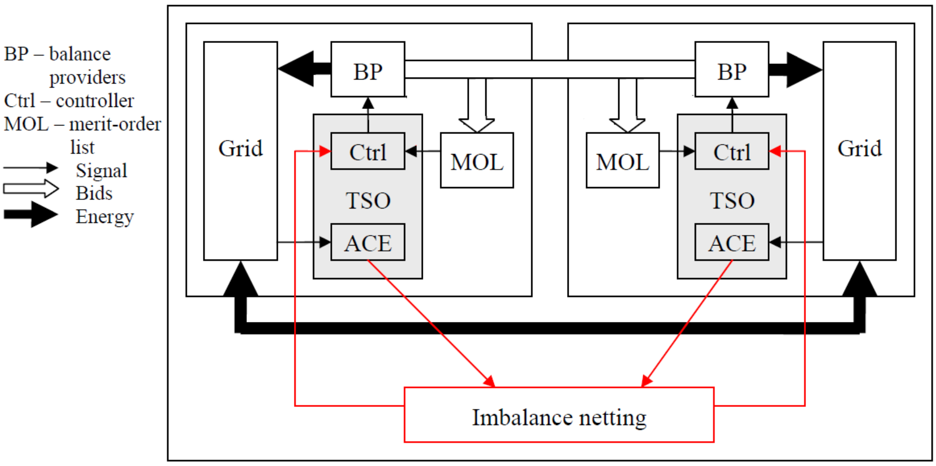

Figure 2.2 Principle of Imbalance Netting

2.1.6 Congestion Management on the Interconnection Lines

In cases of congestion, the allocation of cross-border capacities should be addressed with non-discriminatory solutions. The methodology for allocating the cross-border capacities and physical transmission rights should be approved by NRAs and published to signal that this process is open and competitive. There are several possible methods to allocate physical transmission rights, including cross-border capacities, to market participants (first come, first served, pro rata, NTC-based or flow-based, bilateral or multilateral, explicit or implicit auctions). In Europe, the target model for electricity market integration and congestion management is flow-based price coupling require highly meshed interconnections (i.e., alternative corridors for power flows between the countries).[15] Nevertheless, NTC-based market coupling launched in several EU Member States is likely the best short-term solution in the Black Sea region given lack of meshed interconnections, currently. More sophisticated mechanisms, like flow-based price coupling, could be considered in the long-term at sub-regional level along with the increase in the interconnections (i.e., meshed grid).

Key requirements for congestion management are indicated in Table 2.7.

Congestion management mechanism on the interconnection lines						
		Subregion A1		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
40	Does the regulator approve NTC?					**AM:** Currently only isolated connection (No NTC approach yet) **Others:** Under progress
41	Is there a secondary market for the allocated capacity rights on the interconnection lines?					**AM, GE, UA:** No legislations yet. **UA:** Legislation exists but not practiced yet. Under progress.
42	Is the congestion management scheme on the interconnection lines is harmonized with neighbor countries?					**GE:** NTC approach only between GE & Turkey in practice **MD, UA:** Under progress **AM:** Currently only isolated connection (No NTC approach yet)

[14] https://ec.europa.eu/energy/sites/ener/files/documents/dg_ener_balancing_-_161021_-_final_report_-_version_27.pdf

[15] Flow-based price coupling is being advocated as the target market model for highly meshed grids. It allocates capacity by optimizing the overall order book surplus from the different spot markets, while ensuring that the physical limits of the grid are respected. The consequence, when sufficient capacity is available, is price harmonization across the region.

Table 2.7 Questionnaire Results (Congestion Management Mechanism on the Interconnection Lines)
(based on implementations as of March 2018)

Main Observations and Recommendations

- BSRI countries have been practicing NTC calculations under the scope of the BSTP project. However, only Georgia has already started implementation of NTC based congestion management on the interconnection lines with Turkey. The NTC calculations performed by the common studies of the neighboring TSOs should be approved by the regulators and published in relevant countries at the sub-regional level, like in the case of Georgia-Turkey. Calculation methodology, approval and publication of the NTC calculations should be defined in legislation (also connected with the data transparency issue).
- When the NTC is available, TSOs should allocate the NTC to the most efficient combination of generators in the market coupling process. NRAs should consider the electronic auction mechanisms practiced in Georgia for allocating the NTC to the market players or to consider the methods in other countries, as it has been implemented for the HVDC B2B interconnection between Georgia and Turkey.
- As recommended in the BSRI Wholesale Market Guidelines, market participants should be allowed to trade formerly allocated capacity rights on a secondary market. Nevertheless, development of a secondary market for the allocated capacity rights on the interconnection lines is not the emerging gap to be resolved and can be introduced at a later point along with market developments in the countries.

2.1.7 Real Time Balancing and Ancillary Services

Balancing and Ancillary Services are processes and products that are deployed in real-time, what one might call the operating horizon, when physical transactions occur as opposed to forward schedules. Day-ahead scheduling and market coupling identify the units that are committed to supply the market with energy and reserves for the operating day. However, to operate the market securely in real-time, TSOs must ensure that enough resources are available, given any changes in system conditions from the day-ahead, and that they are dispatched on a moment-to-moment basis in a manner that maintains system balance and security.

The development of separate ancillary services markets was necessary due to unbundling TSOs from generation assets that were formerly used by vertically integrated companies to keep their systems in balance. With unbundling, TSOs lose direct control over the generation assets they had at hand, internally, in the old vertically-integrated company. To keep the electricity system balanced, they need the ability to call on identified generation assets or demand-side assets to do the critical job of balancing the system. This is also important because harmonized ancillary services need to be in place to facilitate core elements of cross-border trading—for example scheduling, balancing, and losses procurement. Ancillary services are products offered or facilitated by the TSO that preserve power quality and balance on the system and thereby allow multiple users to utilize a transmission network while preserving system security.

Real Time Balancing and Ancillary Services						
		Subregion A1		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
43	Are the ancillary services identified in law/Grid code/market rules?					
44	Are standardized definitions used for balancing and ancillary services in the Grid Code? (Like standard definitions in the ENTSO-E Network Codes)?					**MD:** Under progress
45	Are the balancing services priced separately (cost based or market based)?					**All:** Not yet

46	Are the other ancillary services separately priced (cost based or market based)?					**All:** Not yet
47	Are the Balancing Responsible Parties (BRP) defined/required by Grid Code or Market Rules?					**AM, GE:** Not yet
48	Is there any framework defined to monitor ancillary services markets, (monitoring offers of balancing and ancillary service markets and monitoring aspects of cross-border transmission capacity markets)?					**All:** Authority is given in law. However, not in practice.
49	Does the NRA work with TSOs to discuss the harmonization of technical requirements for balancing and ancillary services among regional participants?					**All:** Under progress
50	Does the TSO technically prequalify entities as Balancing Service Providers (BSPs) through a certification mechanism?					**AM:** TSO only prequalifies but not certifies. BSP are not defined in the grid code yet. **All:** No certification mechanism yet
51	Does the NRA oversee the TSO prequalification/certification process for BSPs?					**All:** No legislations yet

Table 2.8 Questionnaire Results (Real Time Balancing and Ancillary Services) - based on implementations as of March 2018

Main Observations and Recommendations

- Real-time balancing and ancillary services are currently not in practice in the BSRI countries. Rather balancing and other ancillary services are identified in grid codes and standardized definitions are used for balancing and ancillary services. Currently, however, in all of the countries, there is no ancillary service market or commercial mechanism in place and ancillary services are obtained by the TSO without specific payment for providing balancing and ancillary services. That is, balancing and ancillary services are not priced separately.
- There is no prequalification and certification mechanism for the BRPs. This is a concern to be addressed in the short-term. BSPs should be prequalified through a certification mechanism, which should exist in the grid code, and the regulators should oversee the prequalification/certification process of the TSO.
- NRAs should work with TSOs (nationally and sub-regionally) to discuss the harmonization of technical requirements for balancing and ancillary services at the sub-regional level.

2.1.8 Market Design and Current Market Structure

Pricing ancillary services on a market basis requires an effective market structure and performance. In the BSRI region, the markets are not yet ready to support competitive outcomes for balancing and ancillary services. Even though efficient and effective wholesale competition is a critical goal, until competitive wholesale markets are in place, TSOs in the region will not have market mechanisms ready for ancillary services and balancing products at the outset of reform.

There has been significant progress in all countries (still ongoing in Moldova) in terms of market design, developing market rules, and frameworks for electricity contracts between the suppliers and consumers.

However, a competitive market has not developed in all countries yet. Therefore, dispatch of major power plants are based on their costs (i.e., merit-order) currently.

Key requirements are indicated in Table 2.9.

Market Design & Current Market Structure						
		Subregion A1		**Subregion C**		
No	**Key Topic**	**AM**	**GE**	**MD**	**UA**	**Comments**
52	Are the Market Rules which describe design and operation of competitive wholesale electricity market exist?					**MD:** Under progress
53	Is the market share of largest three power producers is less than 75%?					**AM:** Almost 75% **MD, UA:** Above 75%
54	Is the market share covered by long-term contracts is less than 30%?					**GE, MD: :** Long-term contracts (annual basis) **AM:** Long-term contracts (several years) **UA:** No long-term contracts in the current market model
55	There is no any long-term agreements with generators for capacity (reserve)?					**GE, MD: :** Long-term contracts (annual basis) **AM:** Long-term contracts (several years) **UA:** No long-term contracts in the current market model
56	Is a Clearing House or Settlements Administrator created?					**MD:** Settlement is performed by TSO currently.
57	Is Metering installed at nodes/delivery points?					
58	Is metering system administrator created?					

Table 2.9 Questionnaire Results (Market Design and Current Market Structure) - based on implementations as of March 2018

Main Observations and Recommendations

- Concerns connected with current competition level:
  - In Moldova and Ukraine market share of largest three power producers is above 75% (almost 75% in Ukraine).
  - In Armenia, market share covered by long-term purchase agreements contracts is above 30%.
- Settlements are currently performed by the TSO in Moldova. However, creation of a MO and transferring the responsibility of settlement to market operator is under progress.
- The following main issues should be addressed in all countries: (1) preconditions for participating in ancillary services supply at cost-based rates (2) how to develop cost-based rates for ancillary services and balancing, and (3) how regulators determine when the market is ready for market-based procurement and then monitoring such markets. Further recommendations for these issues are discussed in Chapter 7.

2.1.9 Renewable Resource Integration

Renewable energy resources (RES) integration is a critical competent of the EU energy market reforms. EU reforms have made integration of renewable resources a priority in Directive 2009/28/EC, which establishes binding renewable targets for all Member States. Hence, renewable integration is a key component of market reform.

In all of the countries, RES integration is promoted by law and RES purchase obligation mechanisms (feed-in tariff) exists. The NRAs have identified framework objectives for the integration of RES and there are already RES power plants connected to the grid. The only concern regarding RES integration is that the TSOs are not promoting RES integration due to technical concerns connected with the intermittent characteristics of the RES.

From the NRAs' perspective, it is important to monitor feed-in tariffs with costs of conventional generators. NRAs should take an active role in analyzing the effects of different levels of RES integration to the grid on market development. TSOs are generally reluctant to accommodate large RES penetrations to the grid given intermittent characteristics of RESs. However, depending on their locations in the grid, certain penetration levels of RESs can even support the grid in terms of transmission investment delays.

Technical standards for the connection of RES producers should be transparent, easily available for investors, and should strike the right balance between system reliability needs and simplicity to promote RES penetration. To ease the stress on system balancing, regulators should establish incentives both for intermittent RES producers to provide improved forecasts of their future production to the system operator and for the system operator to allow those producers flexibility in adjusting their forecasts as better weather forecast information becomes available to them. There could also be a third-party forecaster that assists the grid operator in maintaining accurate forecasts.

2.2 National and Sub-regional Summary

This section presents a summary of charts for the policy/regulatory gaps at the national and sub-regional level.

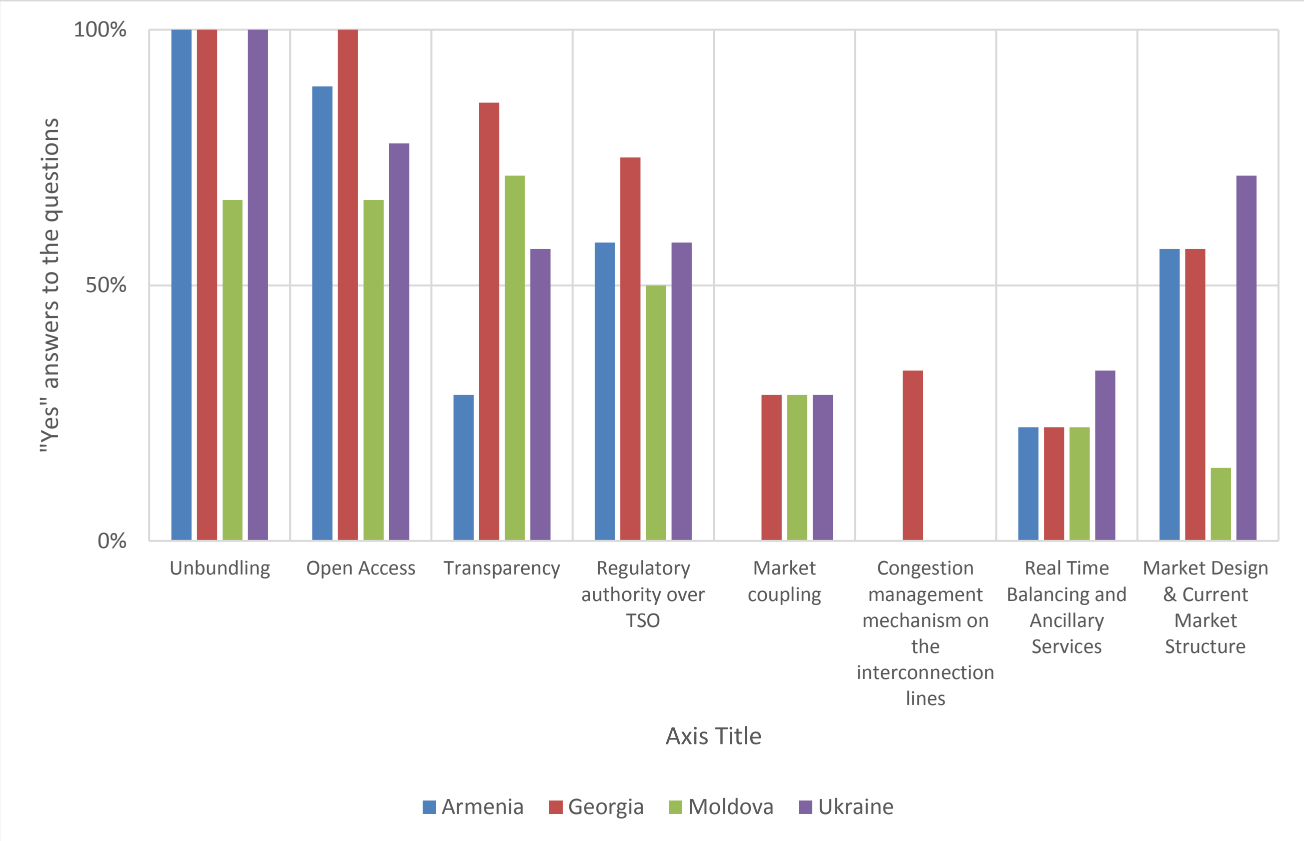

Figure 2.3 Questionnaire Study Results – Comparison of the Countries - based on implementations as of March 2018

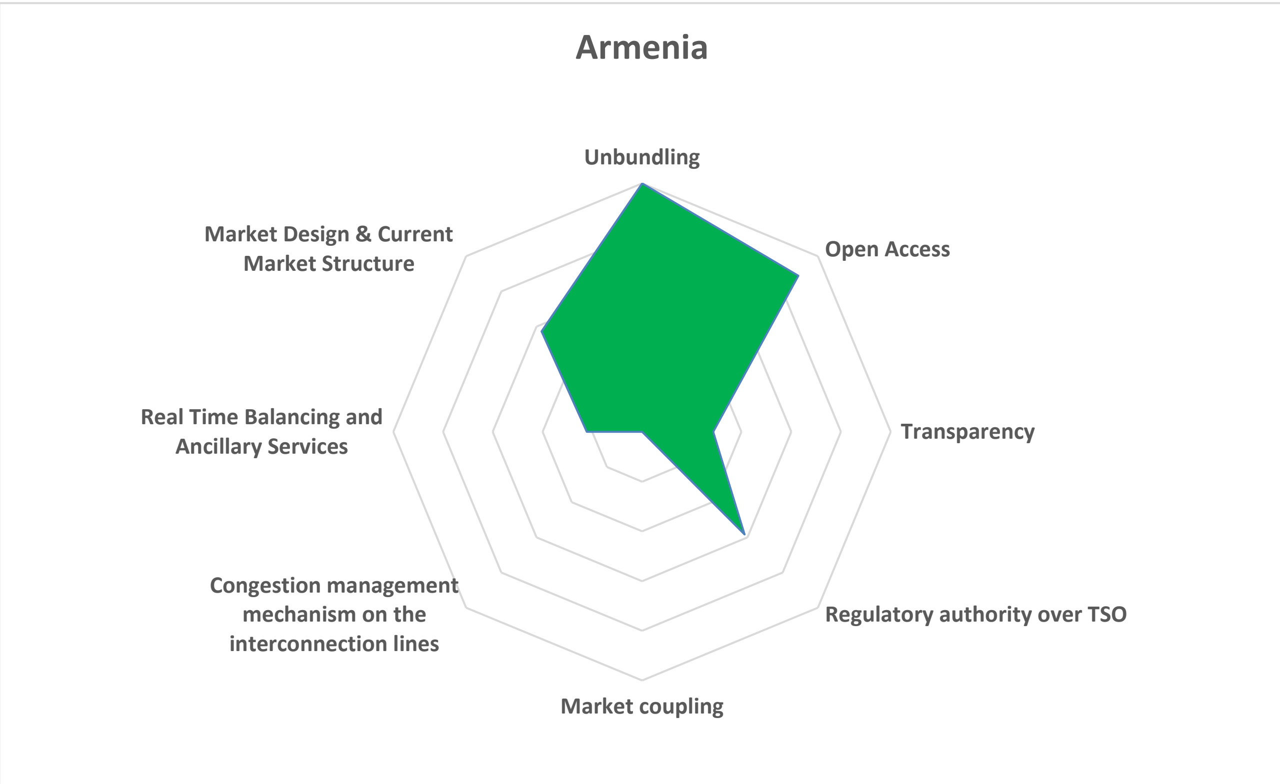

Figure 2.4 Questionnaire Study Results of Armenia (Green area spans the "yes" answers) - based on implementations as of March 2018

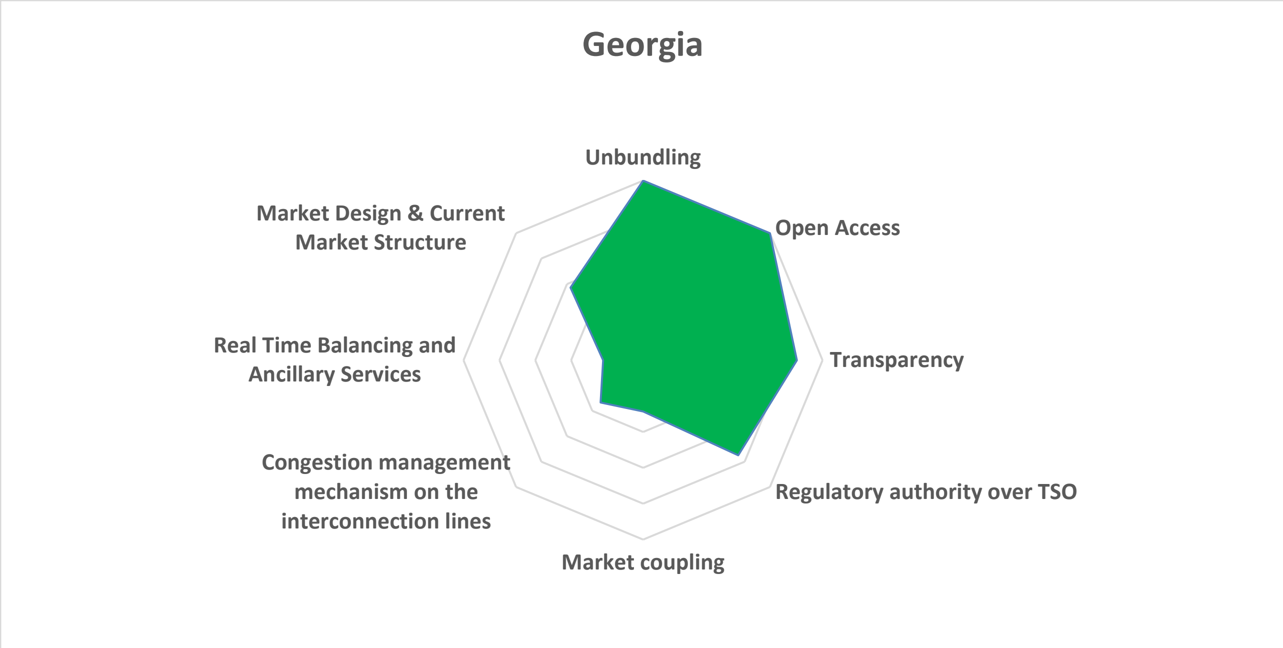

Figure 2.5 Questionnaire Study Results of Georgia (Green area spans the "yes" answers) - based on implementations as of March 2018

Figure 2.6 Comparison of Policy/Regulatory Gaps in Armenia – Georgia Sub-region (Areas span the "yes" answers) - based on implementations as of March 2018

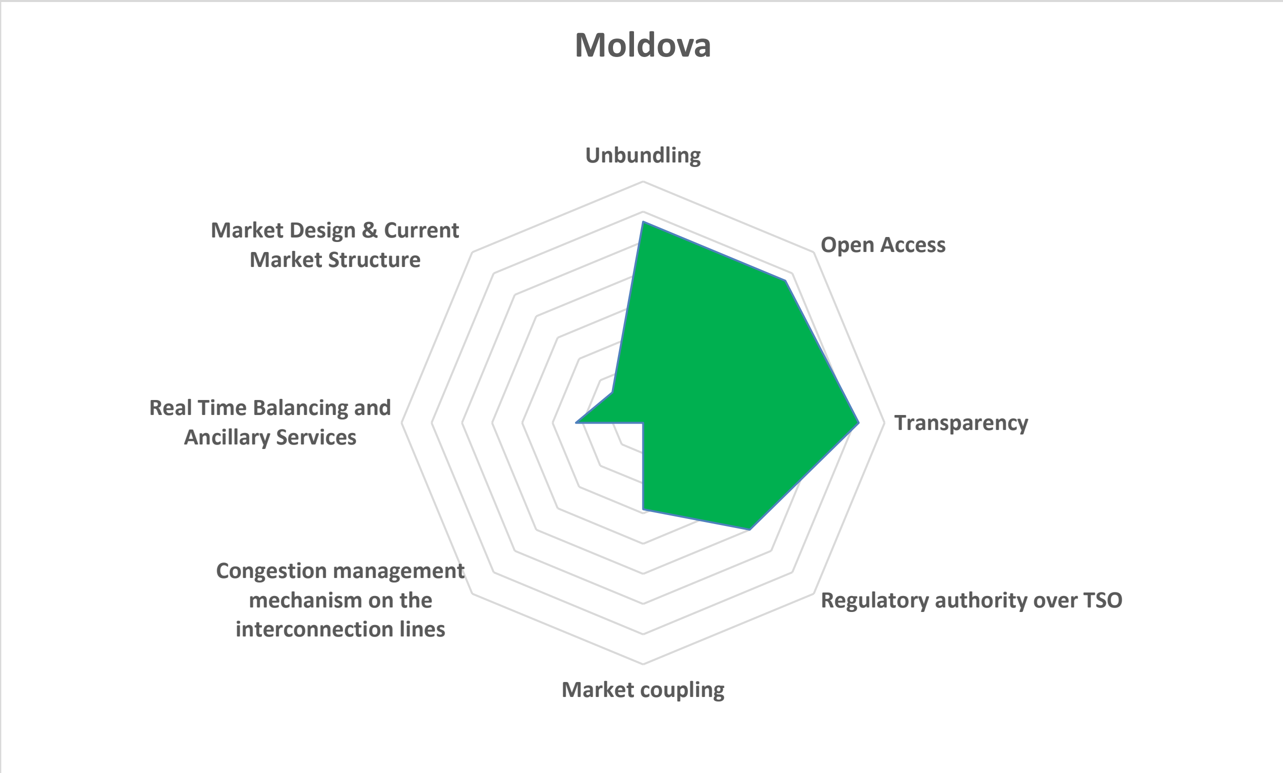

Figure 2.7 Questionnaire Study Results of Moldova (Green area spans the "yes" answers) - based on implementations as of March 2018

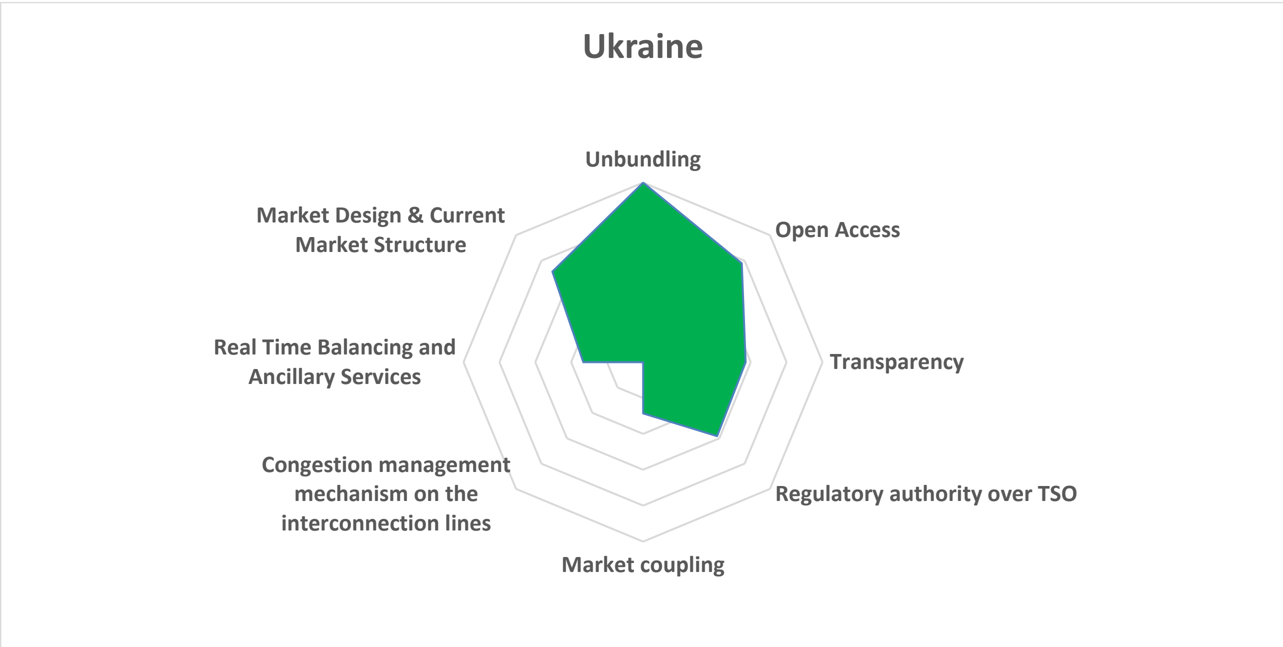

Figure 2.8 Questionnaire Study Results of Ukraine (Green area spans the "yes" answers) - based on implementations as of March 2018

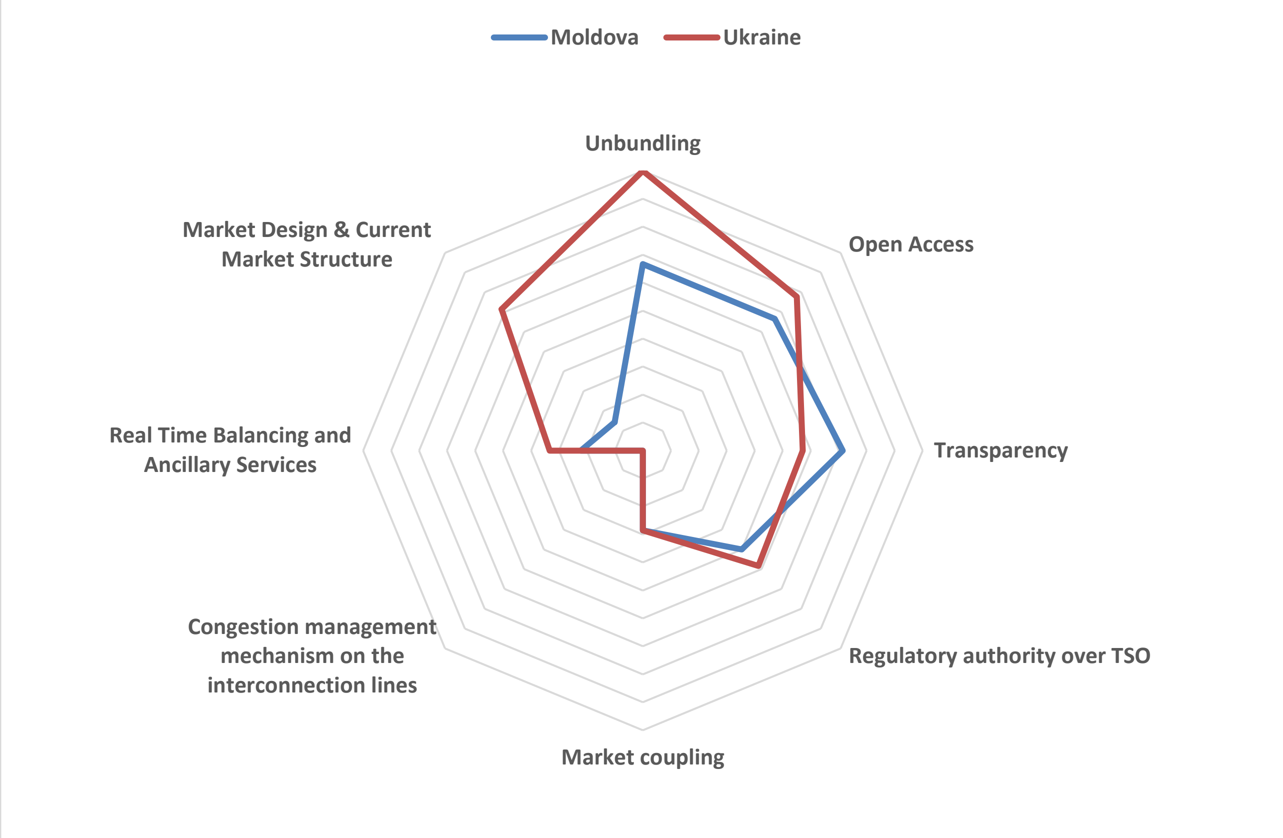

Figure 2.9 Comparison of Policy/Regulatory Gaps in Moldova – Ukraine Sub-region (Areas span the "yes" answers) - based on implementations as of March 2018

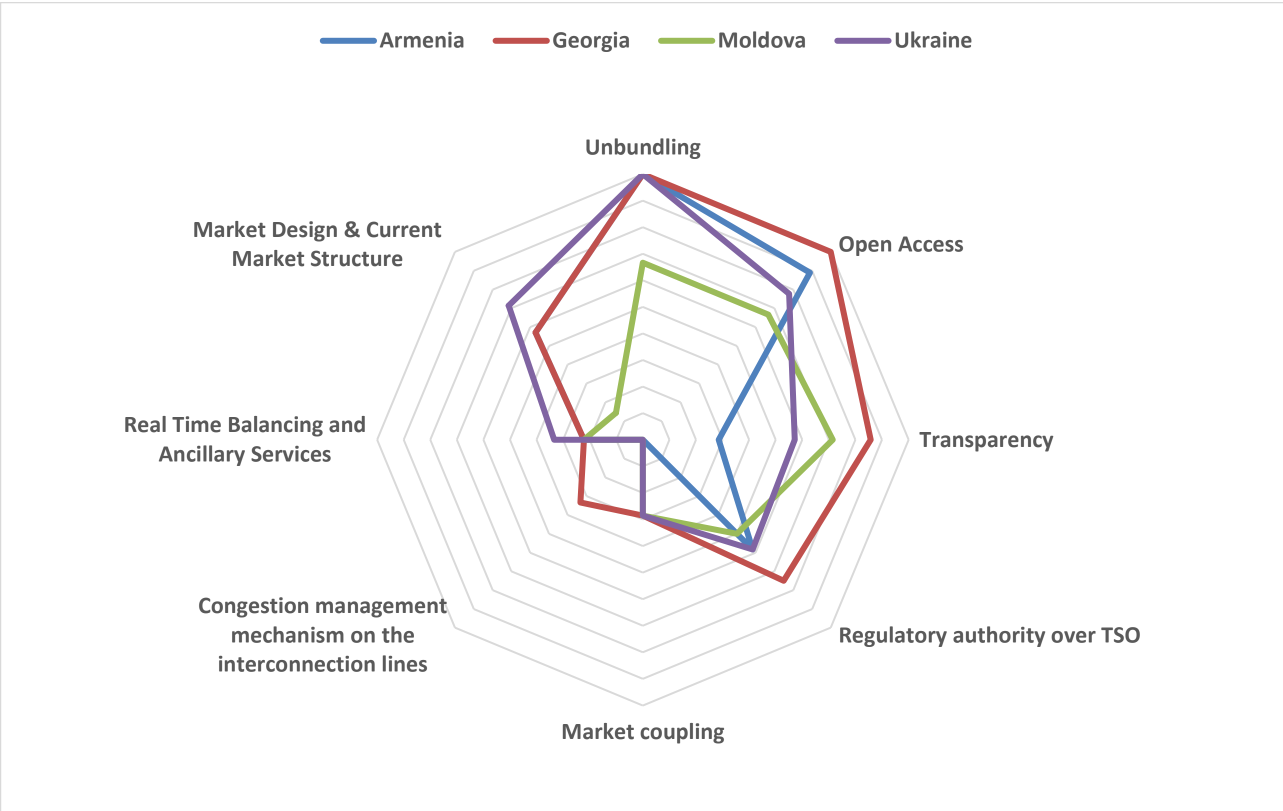

Figure 2.10 Comparison of Policy/Regulatory Gaps in four countries (Areas span the "yes" answers) - based on implementations as of March 2018

3 METHODOLOGY FOR THE ASSESSMENT OF BENEFITS OF CROSS-BORDER BALANCING COOPERATION

When considering the implementation of technical and commercial aspects of integrated balancing models, the BSTP region includes 3 synchronous zones that make integration of balancing markets more complex than in the ENTSO-E community. The BSTP member states are members of the following synchronous zones:

- Armenia is in parallel work with the Iranian transmission network
- Bulgaria, Romania and Turkey are members of UCTE synchronous zone
- Georgia, Moldova and Ukraine are members of IPS/UPS synchronous zone

In addition, some countries are in the same synchronous zone but are not directly connected (i.e. Georgia and Moldova/Ukraine).

However, there is a potential for balancing integration among the BSTP members that should be utilized as their use would provide social and economic benefits to all parties.

As described in the Phase I Report, the technical and commercial potentials are influenced by the systems' participation in different synchronous zones and the existence of present or future AC and DC connections. The potential for balancing cross-border cooperation among the BSTP member states can be recognized and qualitatively assessed for the following sub-regions:

- **Sub-region A1**: Armenia and Georgia
- **Sub-region A2**: Georgia and Turkey
- **Sub-region B**: Bulgaria, Romania and Turkey
- **Sub-region C**: Moldova and Ukraine

There are various possibilities for solutions regarding regional or sub-regional cooperation. However, the above mentioned proposals for sub-regional balancing cross-border cooperation, together with the following qualitative analysis, do not impose any optimal or preferred solution. They are only exercise examples for potential cross-border balancing cooperation among BSTP member states.

A1 and A2 present sub-regions with an asynchronous connection between the Parties and reflect the current cooperation between Georgia and Turkey and the cooperation expected in the near future between Georgia and Armenia. From a technical standpoint, simultaneous balancing cooperation in both sub-regions is possible.

The benefits of balancing integration can result from strictly technical cross-border balancing cooperation or both technical and commercial balancing cooperation. In order to assess commercial benefits, the development of a national balancing market is essential. Where there is no balancing market and no cost for balancing currently exists, benefits as a results of commercial aspects of balancing integration are very limited or do not exist. However, benefits as a result of technical aspects of cross-border balancing cooperation always exist as they are the consequence of a reduction of the capacity kept as a reserve.

At the current status of the balancing markets among the BSTP member states, a high level of diversification in implemented balancing principles and the development of balancing markets is present. The characteristics of each national power system, different initial balancing markets designs and different initial wholesale market conditions present major obstacles in regional balancing integration and significantly affect the results of a quantitative assessment of balancing market integration.

While this Report considers the above mentioned constraints and lack of data (mainly costs and prices), it includes assumed figures that have been presented and discussed with the BSTP and BSRI members. There are two groups of data collected or estimated through BSTP and BSRI initiatives, respectively. First, the BSTP group, was mainly applied within this Report and it covers all of the categories listed below for the assessment of benefits of cross-border balancing cooperation. The effects of these BSTP data were identified through the so called "market based approach". The other group of data was identified through a "cost based approach" sensitivity analysis and covers main alternatives for costs or prices necessary for the assessment of direct benefits.

Thereafter, the agreed upon values were applied in the process of assessing the benefits.

3.1 Potentials for Cross-Border Balancing Cooperation

The potential for cross border balancing cooperation encompasses the following models:

a) Common usage of balancing reserve (**capacity**):
   - Common dimensioning
   - Exchange of balancing reserve
   - Sharing of balancing reserve

b) Common usage of balancing **energy** through:
   - Imbalance netting
   - Exchange of balancing energy over the Common Merit Order List

The main challenge in realizing these options is the availability of cross zonal capacity (CZC) or the capacity between control zones.

All these options require the availability of CZC that can be either guaranteed by an ex-ante reservation after proving socio-economic welfare or the application of a probabilistic approach as suggested in the FG EB (Framework Guidelines Electricity Balancing). To enable full utilization of potential benefits, cross-border capacity must be reserved for an exchange of balancing services in real-time operation which reduces the capacity available for the commercial market. The efficient reservation approach implies simultaneous co-optimization based on real bids in the markets for day-ahead energy and balancing services, hourly reservation, harmonization of balancing product definitions, and flexibility to adjust the solution in an intraday market. During this initial phase of cross-border balancing cooperation in the BSTP region, a process of co-optimization cannot be implemented. Therefore, to assess the benefits of the balancing market integration in the BSTP region, the CZC was assumed as available when taking into account real, physical capacity of the interconnection between the countries especially when interconnecting lines are only HVDC lines.

3.1.1 Common Usage of Balancing Reserve

The common usage of balancing reserves among TSOs, namely FRR and RR, can be divided into the following three scenarios:

a) **Common Dimensioning within the LFC Block** – the opportunity for TSOs operating within the LFC Block to jointly dimension the total volume of balancing reserve.

b) **Exchange of Reserve** – the opportunity for TSOs to procure part of the balancing energy in another area (with no impact on the total amount of balancing reserve in the system).

c) **Sharing of Reserve** – the opportunity for TSOs to reduce the total amount of balancing reserve based on the common usage of a certain agreed part of the reserves. This opportunity is based on very low probability of the situations in which two TSOs will activate their full amount of reserve at the same time. Reserve sharing does not require any harmonization of the balancing product and together with imbalance netting, presents an option that can be applied first and an in efficient manner.

Individual dimensioning – presents the situation without cross-border balancing cooperation.

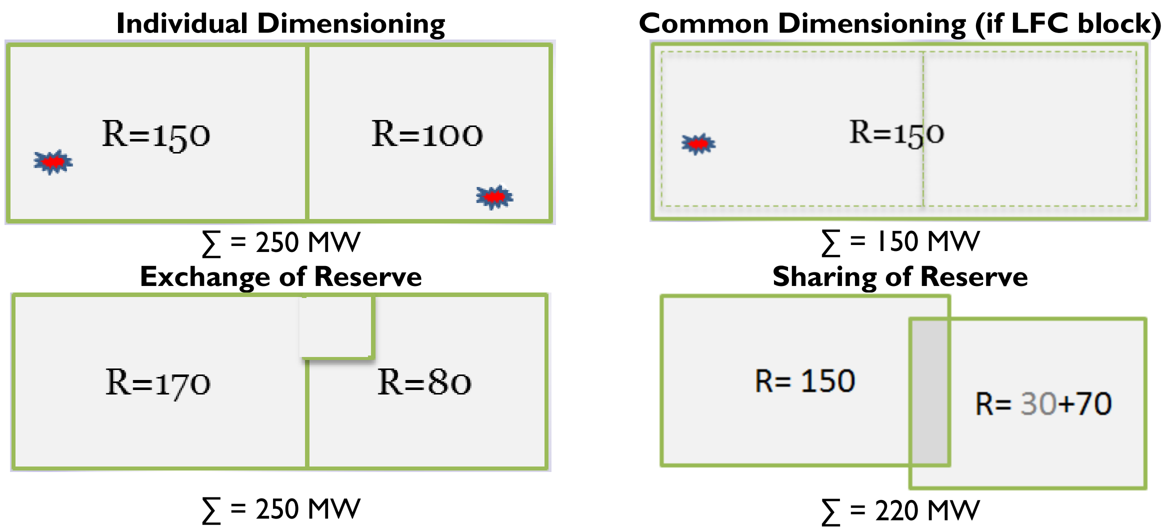

Figure 3.1 – Common Usage of Balancing Reserve (Capacity)

Figure 3.1 describes the technical aspects of the common usage of balancing reserve, primarily referring to the reduction of the capacity kept as a reserve in the system. This reduction in different models of common usage of balancing reserves must follow the rules defined in the ENTSO-E NCs (LFRC, EB), as described in the BSTP Phase I Report.

Commercially, this reduction in capacity (in MW) enables a reduction of costs for the provision of this reserve which then presents a direct commercial benefit that can be acquired through common usage of the balancing reserve.

In addition, released capacity can be used at commercial market and can enable a reduction of operating costs or increase of revenues through increased export which presents indirect commercial benefits of common usage of balancing reserves.

A brief overview of different balancing cooperation scenarios in terms of balancing reserve is given prior to the description of the methodology for the assessment of the corresponding benefits.

Common Dimensioning of Reserve

Only TSOs that are participating in the common LFC Block have the opportunity to significantly decrease the volume of balancing capacity by adopting the dimensioning concept on the level of the LFC Block. This means that the dimensioning incident, as the largest imbalance that might occur as a result of instantaneous change of active power in both directions, is determined for the whole LFC Block rather than individually by each participating TSO (LFC Area).

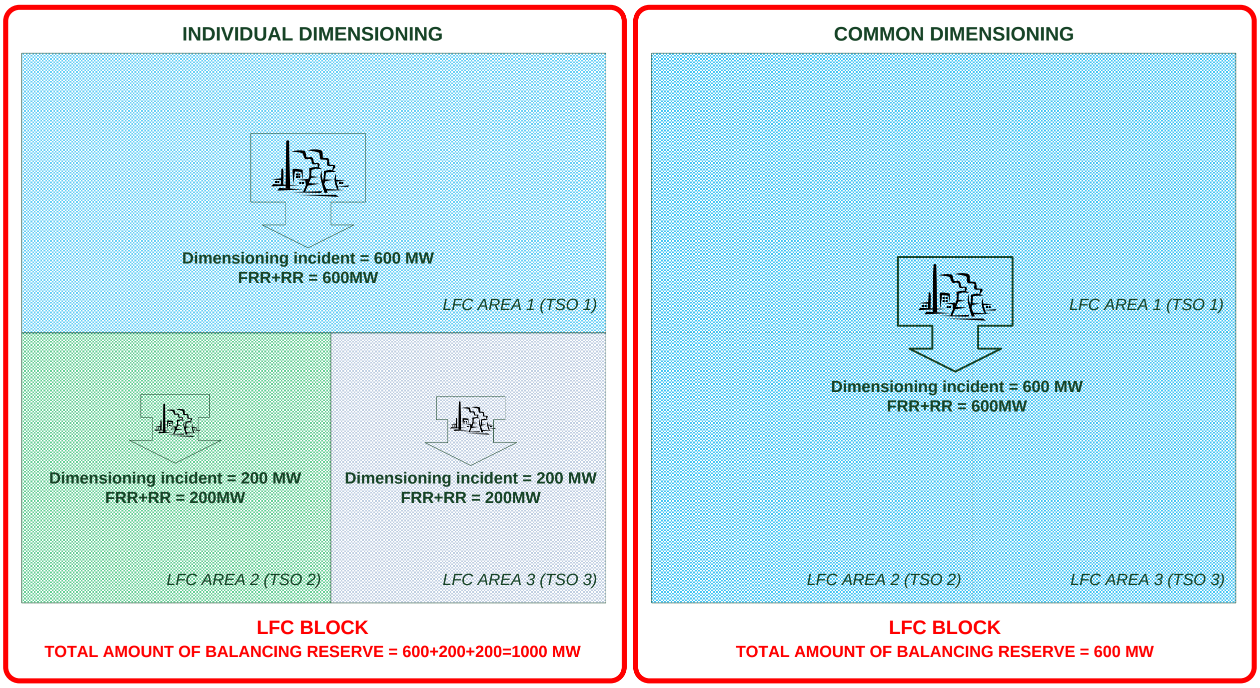

Figure 3.2 – Concepts of Individual and Common Dimensioning of Upward FRR and RR within the LFC Block

The total amount of balancing capacity, determined for the LFC Block, should be split among the participating TSOs with a ratio agreed upon in their operational agreement.

Potential benefits are assessed from two perspectives:

- Direct Benefits - due to a lower reserve capacity requirement, direct costs are lower.
- Indirect Benefits - more generation resources are free to provide energy to the commercial markets.

Exchange of Reserve

Exchange of balancing reserve is an opportunity for a TSO(s) to procure one part of its balancing reserve in another area, thus changing the geographical distribution of balancing reserves but not reducing it. The reason for balancing reserve procurement can include the following:

- Technical – in cases when the TSO cannot provide the required amount of reserve due to technical limitations,
- Economic – in cases when balancing reserves located in another area are more economically efficient.

In order to ensure even distribution of FRR and RR within a synchronous area, the LFC Block has to keep a minimum of 50% of the FRR and RR physically located within their own LFC Block. In the case of exchange of FRR and RR, participating TSOs should sign operational agreements which define roles and responsibilities of reserve connecting TSOs, reserve receiving TSOs and affected TSOs.

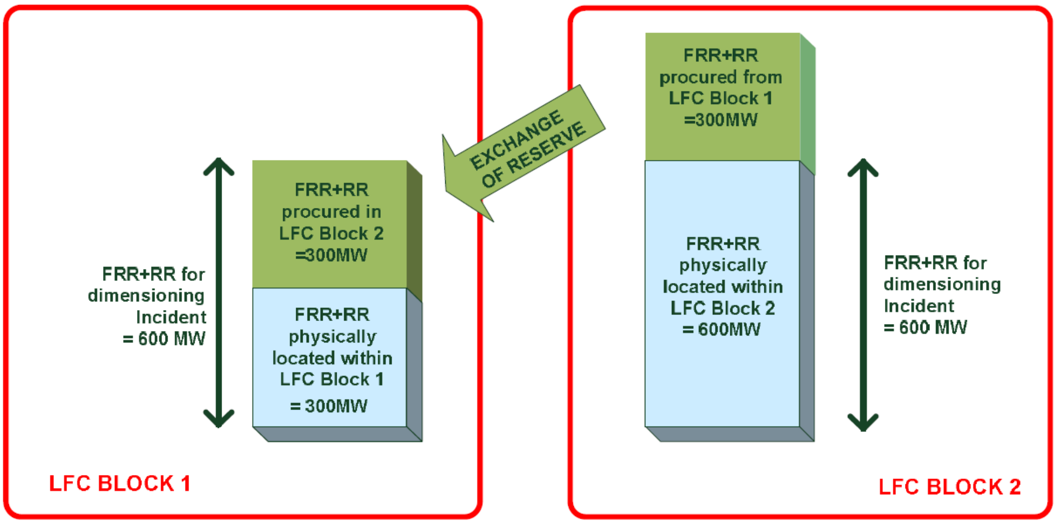

Figure 3.3 – Example of Exchange of Reserve

The potential benefits are assessed from the following perspective:

- Direct benefits – a portion of required reserve capacity will be provided from other TSOs at a lower price.

Sharing of Balancing Reserve

Strict dimensioning principles set by ENTSO-E within the NC LFCR can be, under certain conditions, supplemented by a reduction in balancing reserve capacity due to the sharing of reserves. Sharing of reserves has an impact on the total amount of the reserve capacity within the system while exchange of reserve has an impact only on its geographical distribution. The goal of sharing of reserves is to improve economic efficiency in performing load-frequency control in the system while maintaining the operational security requirements at the same time. For that reason, NC LFCR defines technical limits and requirements for sharing of reserves between the LFC Blocks.

The concept of sharing of reserves is based upon the very low probability of the situations in which two LFC Blocks will activate their full amount of FRR+RR at the same time. There is a potential to reduce the amount of balancing reserves through the common use of one of the agreed upon reserves between LFC Blocks.

The LFC Block is allowed to reduce the total amount of FRR and RR by sharing, only in the following cases:

- When the volume of dimensioning incidents in MW (highest instantaneous change of active power in both directions) is higher than the total amount of FRR + RR necessary to cover 99% of the representative historical record of LFC Block imbalances during one full year period (ending not earlier than 6 months prior to the calculation).

However, the LFC Block is not allowed to reduce the total amount of FRR and RR by more than 30% of the size of the dimensioning incident.

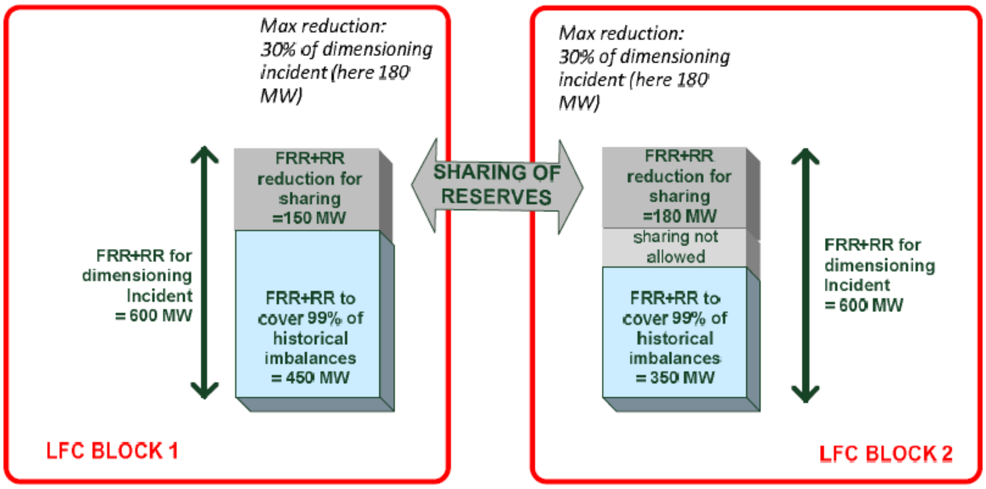

Figure 3.4 – Example of Exchange of Reserve

Potential benefits will be assessed from two perspectives:

- Direct Benefits - Due to lower required reserve capacity direct costs.
- Indirect Benefits - More generation resources are free to provide the energy to the commercial markets.

Common Usage of Balancing Energy

Imbalance netting and cross border exchange of balancing energy present options for cross-border balancing cooperation among BSTP member states. The potential benefits are assessed for the following two options:

- Imbalance netting
- Exchange of balancing energy over the Common Merit Order List

Imbalance Netting

The purpose of the imbalance netting mechanism is to prevent the activation of balancing energy in automated secondary control (Automated Frequency Restoration - aFRR) in opposite directions between participating transmission system operators. This concept involves central optimization of imbalance in control areas in real time, with the aim of minimizing counter-activations of balancing energy.

Imbalance netting provides the most benefits as a result of cross-border cooperation. When combined with sharing of balancing reserve, it can be implemented as the first option in the BSTP case. With small variations, the concept can be applied to all four sub-regions.

Imbalance netting provides benefits based on reduced activation of balancing energy. The reduced activation of aFRR presents an energy reduction in MWh. The economic benefit is calculated by multiplying this reduction in activated aFRR with opportunity price.

The inactivated energy benefits are obvious. However, in the case of underdeveloped balancing markets, it is difficult to monetization these effects. Therefore, it is difficult to estimate the economic benefits gained from imbalanced netting in the BSTP region.

The optimization of automated secondary control (aFRR) is accomplished by applying the imbalance netting mechanism through the participation of other control areas with the purpose of avoiding counter activations whenever possible. If one control area requires the delivery of balancing energy to compensate for lack of energy, while simultaneously another participating control area requires the withdrawal of balancing energy to compensate for the excess of energy, then cross-border optimization takes place before the secondary regulation resource is activated in these control areas, thereby changing the anticipated cross-border exchanges (flows).

Control error of every participating control area ACE (Area Control Error) is transmitted to the central optimization module, in which netting of signals of opposite signs occurs. As a result of this netting process, some correction signals are calculated and transmitted to a particular control system of each control area. After the completion of imbalance netting, the remaining imbalance is redistributed to the secondary control regulators of every control area, so that the necessary balancing energy is reduced.

The economic benefit of this approach is the reduced amount of balancing energy activated by the automated secondary control (aFRR), and hence lower costs of balancing on a regional electricity balancing market.

The potential benefits are assessed while considering the following:

- Resulting imbalances (in MWh) calculated on the basis of "netting" based on the provided data for ACE for one characteristic day in 2015.
- Imbalance settlement price calculated as the mean value of all achieved opportunity prices, weighted with the respective exchanged volumes of balancing energy.

Balancing Energy Exchange with a Common Merit Order list (CMO)

The TSO-TSO model for balancing energy exchange with a common merit order list is the target model for pan European balancing market integration. The principle of this option is that balancing energy bids are sorted in ascending order by their prices and can be used for activation from all participating TSOs. This common merit order list should be established by participating TSOs for each standard product defined in NC EB, separately, for upward and downward bids.

This concept ensures that the cheapest balancing energy bids are used first, thus making this concept the most economically efficient. However, this concept also requires the highest level of harmonization of balancing processes (gate closure time, balancing products, imbalance settlement etc.). In addition, implementation of this concept requires a highly sophisticated telecommunication infrastructure for the activation of aFRR, thus the time framework for implementation of this concept should be longer in practice. For manually activated reserves (mFRR, RR), the TSO-TSO model (which includes a common merit order list) is easier to implement.

The concept of the TSO-TSO common merit order list model is shown graphically in the following Figure:

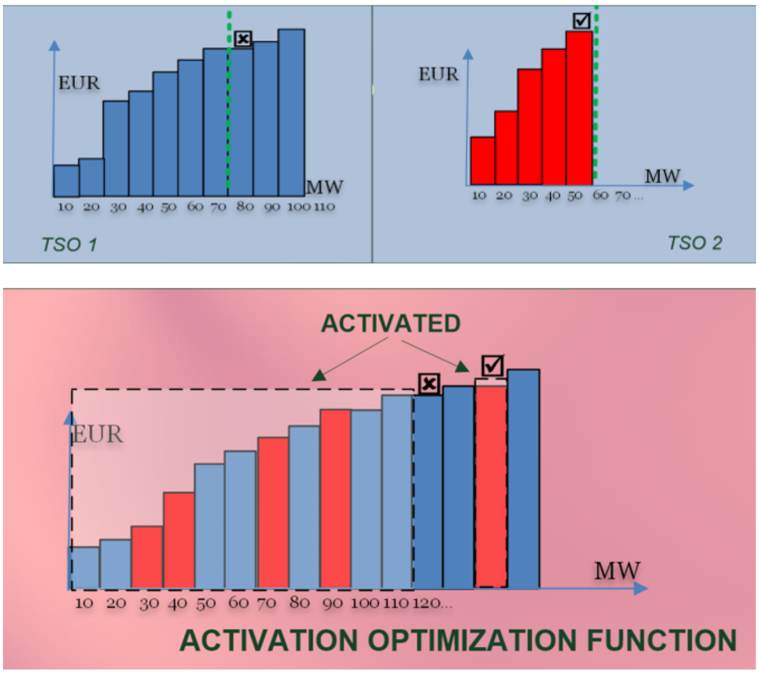

Figure 3.5 – Concept of the CMO Balancing Mechanism

The potential benefits are assessed while taking into account the following:

- Available (or proposed) balancing energy bids (separately for upward and downward regulation and separately for secondary and tertiary regulation).
- Available data of activated secondary and tertiary control from 2015.

3.2 Methodology for the Assessment of Direct and Indirect Benefits of Common Usage of Balancing Reserve and Energy

This chapter describes the methodology that was applied to assess both, direct and indirect benefits of common usage of balancing reserve and energy with corresponding technical and commercial aspects. Classification of the direct and indirect benefits considered in the study for balancing coupling are illustrated in Figure 3.6. In the main analysis, the BSTP "market based approach" for all categories listed below was applied, while the "cost based approach" sensitivity analysis was conducted only for BSRI alternatives for balancing reserve prices used for calculating direct benefits of common dimensioning and reserve sharing, as well as upward and downward regulation energy prices for imbalance netting.

The "cost based" approach assumed undeveloped balancing (including other markets), the sensitivity analyses was not carried out to assess indirect benefits of common dimensioning and reserve sharing as well as the benefits of cross-border balancing cooperation through the common merit order (CMO) list as these analyses assume well-functioning of both, wholesale and balancing markets.

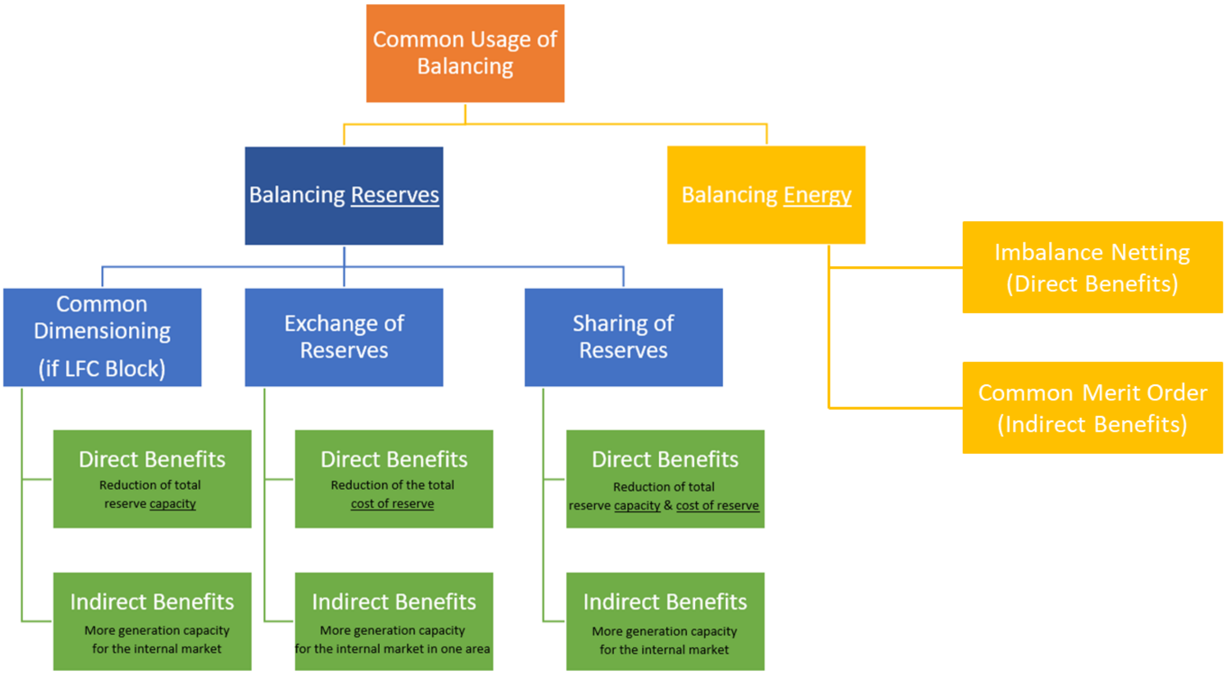

Figure 3.6 Direct and Indirect Benefits from Common Usage of Balancing Reserves and Energy

3.2.1 Direct Benefits of Common Dimensioning & Reserve Sharing

The direct benefits are realized through a reduction of direct costs when ensuring balancing capacity. These benefits are assessed in the following way:

Reduced costs [$] = Reduced capacity [MW] x Market/Regulated price [$/MW]

a. **Reduced Capacity** – estimated by EKC, in accordance with rules determined in ENTSO-E NC (LFCR and EB) and in line with initial assessments related to the BSTP member states given in the BSTP Phase I Report.

b. **Market/Regulated Price** [$/MW] – this data was requested in a questionnaire provided to the TSOs.

The price of reserve is taken from the questionnaires submitted by the TSOs. In some cases, information about market or regulated prices for reserve capacity is lacking.

To overcome this lack of information, these prices are estimated on the basis of the methodology applied by the Serbian Regulatory Agency in calculating regulated prices of the secondary and tertiary reserve.

According to this methodology, the estimation of these prices are made when taking into account that capacity used as a reserve is partially activated and paid through payments for balancing energy and is partially reserved and not used in the commercial market. The time during which capacity is not used in the commercial market provokes a loss of revenue for the producer.

The estimation of this loss of revenue takes into account the following energy and economic assumptions:

- Energy Assumptions:
  - planned capacities (in MW) which will be reserved for secondary and tertiary reserve
  - estimated equivalent operating time of units during the year, taking into account technology type
  - assumed energy which will be delivered as balancing energy and charged at the price of balancing energy
- Economic Assumptions:
  - electricity market prices
  - balancing energy prices

Based on the above defined values, the maximum possible energy loss is estimated by multiplying reserved capacity and equivalent operating time by power plant (technology) type.

The quantity of energy which will not be placed in the market is lower than the maximum possible energy loss. With the aim to estimate this, coefficients for the reduction of maximum possible loss of energy due to capacity reserve are introduced as separate coefficients for secondary and tertiary reserve.

These coefficients consider the following:

- reserve capacity is partially used to produce balancing energy
- in hydro power plants, good planning in terms of the water flow can save water and can produce and sell electricity during some other period of time (especially when tertiary reserve is provided from storage hydro power plants)
- in thermal power plants, energy is lost irreversibly, except when there is not enough primary fuel (coal/gas) for electricity production (which is not a usual case).

When considering the above, the study concludes that a producer has a wider possibility to operate the capacities reserved for tertiary rather than for secondary regulation, and due to this fact, the coefficient applied for secondary regulation is higher than for tertiary:

- coefficient for energy lost due to secondary regulation: 0.50.
- coefficient for energy lost due to tertiary regulation: 0.25.

To calculate the economic (monetary) value of the lost energy, wholesale prices are used. In the case where wholesale prices are not available, the average weighted operating costs of the thermal units are used.

The loss of revenue is calculated by multiplying the energy which could not be placed in the market due to secondary and tertiary reserve and corresponding price. Loss of income is calculated separately for the secondary and separately for the tertiary reserve.

The price of the reserve capacity is calculated by dividing the loss of revenue and the capacity reserved for secondary and tertiary reserve and it is expressed in monetary units/MW [$/MW] as outlined in the tables below.

Country	Secondary Reserve/aFRR (MW)	Thermal/Hydro Ratio	Wholesale Price ($/MWh)	Reserve Price $/MW
Armenia	40	0.8/0.2	33.759	11.6
Bulgaria	160	0.5/0.5	36.1	10.3
Georgia	60	0.3/0.7	54.6	14.8
Moldova	40	0.9/0.1	59.7	21.3
Romania	350			13.4
Turkey	520	0.5/0.5	51.7	15.5
Ukraine	430	0.8/0.2	36	12.3

Table 3.1 – Reserve Capacity Prices – Secondary Reserve

Country	Tertiary Reserve /mFRR&RR(MW)	Thermal/Hydro Ratio	Wholesale Price ($/MWh)	Reserve Price $/MW
Armenia	170	0.8/0.2	33.759	5.8
Bulgaria	1000	0.5/0.5	36.1	5.2
Georgia	260	0.3/0.7	54.6	7.4
Moldova	200	0.9/0.1	59.7	10.6
Romania	1000			7.1
Turkey	1000	0.5/0.5	51.7	7.7
Ukraine	1000	0.8/0.2	36	6.2

Table 3.2 – Reserve Capacity Prices – Tertiary Reserve

The calculation of the reserve capacity price is prepared by the Regulator (particularly in cases where no developed market exists and where one dominant market player is present). In that case, the Regulator is needed to set the fair price.

The described methodology is based on the methodology applied specifically in Serbia. However, regulators in the Black Sea region can develop their own methodologies that will take into account different characteristics of the power systems in their respective countries.

The same reserve capacity price is applied to calculate the direct benefits of common dimensioning of reserve and reserve sharing.

As explained in the introductory chapter, the current BSRI activities are focused on balancing market regulatory development (in Armenia, Georgia, Moldova and Ukraine) and considering their results, additional sensitivity analysis have been performed while taking into account the following reserve capacity prices:

Country	BSTP Assumptions		BSRI Calculations	
	Secondary Reserve Price ($/MW)	Tertiary Reserve Price ($/MW)	Secondary Reserve Cost ($/MW)	Tertiary Reserve Cost ($/MW)
Armenia	11.6	5.8	9.87	4.46
Georgia	14.8	7.4	10.24	4.60
Moldova	21.3	10.6	3.19	0.88
Ukraine	12.3	6.2	3.17	0.27

Table 3.3 – BSRI and BSTP Reserve Capacity Price for Armenia, Georgia, Moldova and Ukraine

These figures are based on production cost data collected from the power generation utilities and in comparison with the classical "market based approach," this type of analysis was identified as "cost based. Details of cost calculations and assumptions are presented in Section 4.2.

3.2.2 Indirect Benefits of Common Dimensioning & Reserve Sharing

Cross border balancing cooperation leads to a reduction of reserve capacity and provides more generation resources for participation in commercial markets. These are considered indirect benefits and they are estimated through system operation simulations and operating cost decreases.

An evaluation of the potential benefits of the common usage of balancing reserve are observed as illustrative examples of real power systems in the Black Sea region.

To conduct the analysis, the power system operation model or market model that incorporates various aspects of the commercial markets is created in the GTMax software tool. The Generation and Transmission Maximization Program (GTMax) is the software tool for the simulation of a complex electricity market as well as power system operational issues, for both competitive and regulated environments.

Specific analyses were carried out with the aim to assess potential indirect benefits of reduced reserve capacity, taking into account the following:

- Power plants are modelled per technology cluster (with their technical and economic parameters), based upon the following relevant sources and studies:
  - Optimal Power Flow (OPF) Study[16]
  - Updated questionnaires
  - *EKC internal database and expertize in market modelling.*
- Demand is modelled with hourly load resolution based on the data provided in questionnaires
- Probable levels of energy exchange (export/import) with neighbouring countries is modelled as defined by NTC values
- The model is simulated for a typical week in winter (3rd week in January 2020)

The following two electricity market simulations were performed, based on the principles of the day ahead market:

- Simulation I - electricity market optimization for each system of interest, with individual dimensioning of balancing reserve
- Simulation II - electricity market optimization for each system of interest, with common dimensioning and reserve sharing

A comparison between the two simulations is performed to quantify market benefits for each system, in terms of a change of revenues and the costs of system operation.

Market Modelling and Simulations

The hypothesis and assumptions used for market modeling are:

- Analysis is performed for a characteristic week (3rd week in January) in 2020
- The following countries are considered in the cross border balancing cooperation analysis: Armenia, Georgia, Bulgaria, Moldova, Romania, Turkey, Ukraine, within the following sub-regions:
  - Sub-region A1: Armenia and Georgia
  - Sub-region A2: Georgia and Turkey
  - Sub-region B: Bulgaria, Romania and Turkey
  - Sub-region C: Moldova and Ukraine
- The electricity market model of the BSTP region is created:
  - Using GTMax software as market modelling software

[16] Black Sea Regional Transmission Planning Project Optimal Power Flow Modeling Results

- Using collected data
- Defining transmission constraints as NTC constraints based on the ENTSO-E methodology
- Possible level of exchange of energy (export/import) with neighboring regions is modelled based on defined NTC values

Figure 3.7 – BSTP Regional Synchronous Zones

Chronological market simulations with generation portfolio optimization for a particular characteristic week are performed at an hourly resolution. The aim is to obtain optimal system dispatching subjected to constraints between market areas. As the main output, system optimization provides generation dispatch and marginal clearing prices (MCPs) as well as energy exchanges between the market areas. The "chronological" aspect refers to the preservation of the chronological sequence of events in the simulation by using a calendar and also by considering, in the optimization process, constraints given by previous states. By applying inter-temporal constraints, the results provide increased realistic levels of available energy (and capacity) in each time step.

Power system operations are simulated with a 1-hour time step and by the means of a total system cost minimization (including fuel costs and CO2 emissions penalties), while taking into account many technical constraints of the system. Establishing equilibrium between the generation and demand of electricity depends on many parameters, such as the following: availability of primary energy sources, prices of fuel, bidding strategies, etc. The implicit assumption applied within the market simulation in this Study is that the market operates perfectly (as assumed for the purposes of the study). In this case, the system marginal price is set by the operating cost of the most expensive unit on-line during a given time period. With an inelastic consumer bid curve, which is typical in electricity markets, the total dispatch cost minimization provides maximization of social welfare.

GTMax (Generation Transmission Maximization) software is electricity market modelling software developed by Argonne National Laboratory (under US Department of Energy). GTMax performs generation optimization (including hydro-thermal coordination) and simulates spot market transactions based on profit maximization from electricity market, with meeting system loads within system reliability constraints. Both zonal and nodal modelling is supported. GTMax uses LINGO solver which incorporates linear, nonlinear and integer techniques. Inputs and outputs are described in the following Figure:

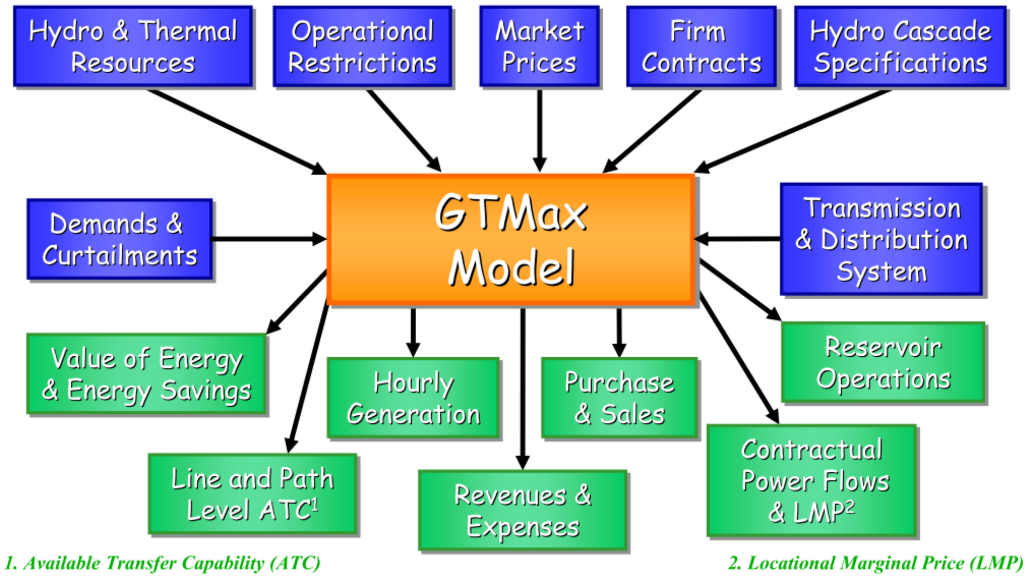

Figure 3.8 – Inputs and Outputs within GTMax Model

The following results are obtained from electricity market simulations and are determine for each country:

- Total consumption (demand + pumping)
- Generation dispatch per technology
- Electricity balance
- Marginal price of generating electricity
- Energy export/imports between countries
- Total operating costs per country

Assessment of Specific Operating Costs

Simulations of the market operation assume engagement of various generating units (technology clusters) according to their specific operating costs, characterized as short-run marginal costs that include fixed and variable O&M costs, environmental and fuel costs but no capital (investment) costs.

To determine specific operating costs, power plants in each country have been grouped in the following technology clusters, on the basis of available datasets (from questionnaires, OPF models, assumptions concerning fuel prices, etc.):

- Res Hydro (Hydro power plants with Reservoirs)
- RoR Hydro (Run-Of-River hydro power plants)
- PS Hydro (Pumped Storage HPPs)
- Gas-existing (Existing gas-fired units)
- Gas-NEW (New gas-fired units with higher efficiency and lower costs)
- Lignite & Coal-existing (Existing lignite/coal-fired units)
- Lignite & Coal-NEW (New lignite/coal-fired units with higher efficiency and lower costs)
- Nuclear
- Wind
- Solar

Within defined technology clusters, hydro power plants and RES have been recognized as clusters that participate in the wholesale market with operating costs of 0 $/MWh as they have a priority in the merit order list. In the following tables, no specific operating costs are showed for these technology clusters.

In all analyzed countries, specific operating costs for thermal technology clusters have been estimated for year 2020.

Specific operating costs have been defined on the basis of the data used in [7] and [8] with the only change related to CO2 taxes due to changes of forecasted CO2 prices developed in the last 2-3 years, after the finalization of the OPF Study. Furthermore, different CO2 prices forecasts still show a variety of trends, especially after 2025 when there are forecasts that reach either 44 or 110 $/tCO2 (or even more) in 2050. However, historic information shows significantly lower levels which are expected last until at least 2020. After reaching a minimum of around 5.5 $/tCO2 in 2013 and recovery to 8.8 $/tCO2 in 2015, the current CO2 price is again around 6 $/tCO2 (Feb 2017). Therefore, the proposed CO2 price for this study is 6 $/tCO2 (12$/tCO2 was assumed in the OPF Study).

All other prices and costs (fuel, variable and fixed operating costs) can be applied as given in the OPF Study as no significant changes in relevant forecasts related to year 2020 occurred in the last 2 or 3 years.

On the basis of the approach described above, specific operating costs (in $/MWh) have been developed for each technology cluster in each power system and presented in the following table and diagram (Table 3.4 and Figure 3.9). These values are used in market simulations and applied to a characteristic winter week in the year 2020 with GTMax.

Country	GAS existing	GAS new	LIG/COAL existing	LIG/COAL new	Nuclear
Armenia	73.0	47.1			19.0
Bulgaria	97.3		52.3		27.5
Georgia	73.1	66.6		38.6	
Moldova	85.2		43.4		
Romania	92.4	73.5	51.0		29.4
Turkey	74.8	74.8	55.5	52.7	31.3
Ukraine	79.5	76.0	58.3	48.5	25.3

Table 3.4 – Specific Operating Costs – Summary for 2020

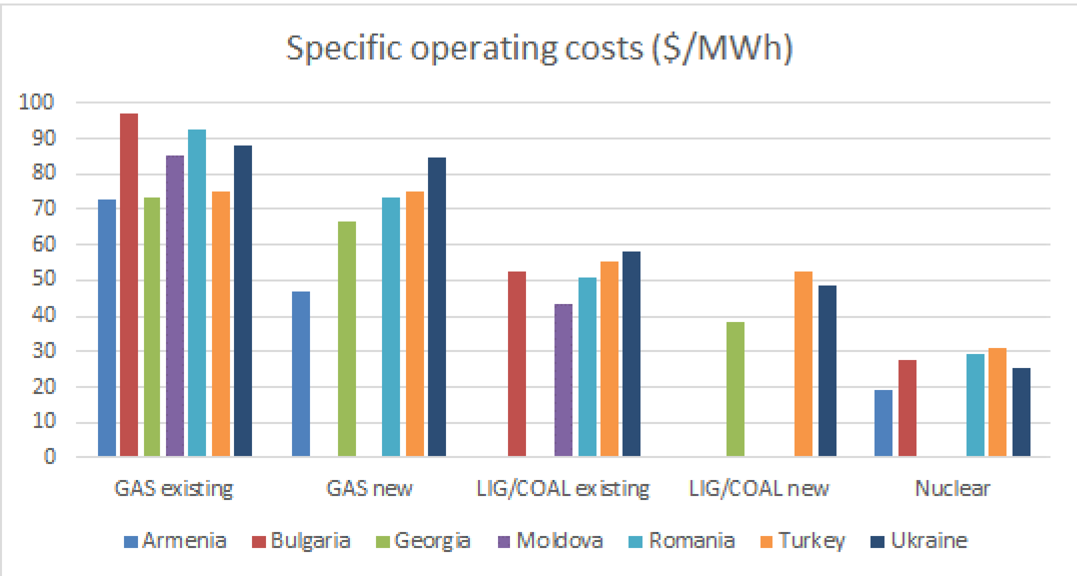

Figure 3.9 – Specific Operating Costs – Summary for 2020

Operating costs for nuclear technology are the lowest while the highest are the costs for gas technology as a result of natural gas prices. This merit order corresponds to the expected general merit order that includes: nuclear, lignite/coal, and gas. Despite a fluctuation to higher fuel prices in one energy source, this order would remain the same (as a higher price increase in one energy source usually leads to an increase in the others).

It is important to note that the goal of market simulations (an assessment of the indirect benefits of the reduced reserve capacity and increased power available for the commercial market) is the difference in market operation in two cases (with individual reserve provision and with cross border balancing cooperation) and not the general market positions, operating costs or marginal prices.

Specific Operating Regimes of Different Technologies

The operation of hydro power plants is simulated in accordance with their type: mainly distinguished by the volume of the reservoir and possibilities for regulation of the inflow (RES Hydro and RoR Hydro). The operation of hydro power plants with large reservoirs is completely freely optimized within market simulations respecting installed capacity and available monthly energy (available energy in a selected characteristic week). The operation of run-of-river hydro power plants is optimized with certain constraints (i.e. limited possibility for regulation of the inflow) which are modelled at a certain level of constant generation in all analyzed hours. For both types of hydro power plants, the operation in average hydrology conditions was assumed. In addition to these two types, the operation of pumped storage HPPs is completely freely optimized in the market simulation (respecting installed capacity and reservoir volume) with the aim to reduce total operating costs (produced during peak price hours and consuming/pumping during low price hours).

Operations of renewable sources are simulated as “must run” generation, generation with the highest priority. Hourly profiles for a characteristic analyzed week are defined on the basis of installed capacities and corresponding hourly capacity factors for each type of simulated renewable sources.

The operation of thermal power plants is optimized in market simulations, respecting technical and economic parameters, including forced and maintenance outage rates.

Transmission Capacities Assessment and Determination of Zones

Transaction-based transmission capacities (NTC) are used herein as the representation of network constraints converted for usage within the market simulations (assessment of the indirect benefits of the reduced reserve capacity and increased power available for the commercial market).

As concluded by numerous studies, the detailed market simulations for future years (with a full grid model defined at the substation level) are unrealistic, either due to computational challenges or a lack of detailed data. However, there are approaches based on the country level and market simulations with congestion-free zones equal to the whole country, which lead to too optimistic results as the physical characteristics of the grid and grid limitations are not taken into account (in particular for huge and complex power systems).

Zones are usually defined as a predominantly supply-rich area (area with excess of generation) or demand-rich area (area with lack of generation) or areas without overloaded network elements. Zones can also be defined as predominantly RES or hydro areas.

The following indirect criteria have been identified in the zoning process:

- **Network Density (Degree of Meshing and Grid Constraints):** This criterion is based on analyses of the transmission network elements, loading in normal and contingency operating regimes. In the case of high meshing in the system, constraints seem unlikely. However, in the opposite situation, constraints are possible – meaning that an insufficient network density causes a splitting of zones.

- **Assignment of Supply-Rich, Demand-Rich or RES Priority Areas:** The level and spatial distribution of generation and load centers can point to potentially highly loaded parts of the network that can be candidates for zoning.
- **"Forced" Grid Areas or Market Areas:** In some cases, market and grid areas are already existing or planned to be introduced. Usually it is a decision of the TSO to determine forced grid/market areas based on a variety of criteria.

The full network model of the BSTP power system was used in the process of determining zones and inter-zonal links. In the case of a full transmission network, load flow results of an analyzed regime (winter peak) will show (or not) some overloaded network elements for contingency (n-1) analyses. This will show if there are (or not) some constraints in the network and if there is (or is not) the need for zoning of the system based on this criteria. In addition to this, when assessing the generation and load centers in different areas, the density of the network and possibilities to export or import to and from that area could be sufficient.

It should be noted that in this normal and contingency analyses, transmission network elements' limits are taken as their thermal limits. Loading of transformers could be higher but within defined acceptable limits: limits are usually taken as nominal capacity in normal operating regimes but they can have 20-40% increase in contingency regimes, which is in accordance with individual operation practices among some of the TSOs in the BSTP region.

Total and Net Transfer Capacity (TTC, NTC) is evaluated in the Black Sea region in all directions, for the chosen winter peak regime (3rd week in January in 2020) and these values are applied in market simulations with GTMax. Details about the zoning and calculated network constraints are given in the Appendix.

The general definitions of transfer capacities (TTC, NTC) and the procedures for their assessment are given by ENTSO-E (i.e. its preceding association ETSO [6]).

The methodology used in performing this study is based on these prerequisites.

Direction A→B

$$TTC^{A\to B} = BCE^{A\to B} + \Delta E_{max}^{A\to B}$$

$$NTC^{A\to B} = TTC^{A\to B} - TRM^{A\to B}$$

Direction B→A

$$TTC^{B\to A} = BCE^{B\to A} + \Delta E_{max}^{B\to A}$$

$$NTC^{B\to A} = TTC^{B\to A} - TRM^{A\to B}$$

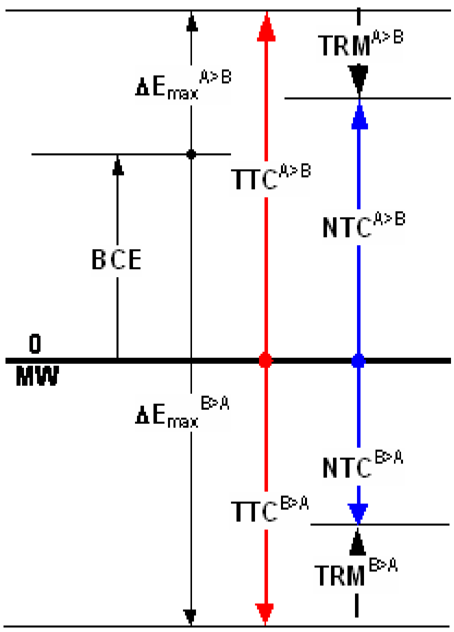

Figure 3.10 - NTC Definitions

Base Case Exchange (BCE)

In the base case, for a given pair of neighboring control areas (A and B) for which capacities are to be computed, a global exchange program called Base Case Exchange (BCE) exists. BCEs are the program (contractual) values related to the base case model.

Maximum Additional Exchange (ΔEmax)

The maximum additional program exchange (over the BCE) that meets the security standards is marked with ΔEmax. An additional program exchange is performed by increasing generation in area A and simultaneously decreasing generation in area B.

In some cases, it might be necessary to lower the BCE in order to calculate the TTC. In that case, the ΔEmax is negative (obtained by decreasing in A and increasing in B).

Total Transfer Capacity (TTC)

TTC is the maximum exchange program between two areas, compatible with the operational security standards applicable on each system, if future network conditions, generation and load patterns were perfectly known in advance.

TTC = BCE + ΔEmax

When computing TTC from control area A to B, generation is increased step-wise in area A and decreased in area B, where the accepted step is 50 MW.

Transmission Reliability Margin (TRM)

TRM is a security margin that deals with uncertainties on the computed TTC values arising from:

- Unintended deviations of physical flows during operation, due to the physical functioning of primary and secondary control
- Inaccuracies, e. g. in data collection and measurements

In the present Study, used TRM value is applied according to the data provided by TSOs.

Net Transfer Capacity (NTC)

NTC is the maximum exchange program between two areas compatible with security standards applicable in both areas, taking into account the technical uncertainties of future network conditions.

NTC = TTC-TRM

3.2.3 Benefits of Imbalance Netting

The economic benefit of imbalance netting is based on a reduction in the amount of balancing energy activated for aFRR. To demonstrate possible potential savings from imbalance netting mechanisms, three cases were created, simulated and compared in terms of accounting aFRR activated energy:

- **CASE 1**: aFRR activated energy is quantified as a single value within a settlement period of 1 hour (cumulative value of activated energy in both positive and negative directions; "netting in time" on the level of 1 hour)
- **CASE 2**: aFRR activated energy is quantified as a single value within a settlement period of 15 minutes (cumulative value of activated energy in both positive and negative directions; "netting in time" on the level of 15 minutes)
- **CASE 3**: aFRR activated energy is quantified separately for upward and downward regulation within the settlement period (no "netting in time").

Imbalance netting savings are assessed on the basis of the reduced activation of aFRR in a selected characteristic day in 2015 and opportunity prices determined as average weighted prices for aFRR activated energy in each power system for the year 2015.

With this arrangement, all participating systems reduce their regulation efforts, and therefore the volume and often the price of regulation. On average, the prices for upward regulation will go down, while the prices for downward regulation will go up. This is of course an advantage for BRPs with imbalances (the “consumers”), and a disadvantage for BSPs (the “producers”). However, conservative assumption related to implementation of the same opportunity prices with and without imbalance netting is applied for this assessment.

The ACE data (2 seconds measurements) provided by the TSOs (in the questionnaire) is used to determine the volumes of reduced activation of aFRR. In the case of data gaps, 2 second values have been created randomly but in correlation with total generated power in each power system and K-factor, as explained in Section 4.1.

In the case where there is no imbalance netting, the volumes of aFRR activation are defined directly on the basis of ACE data that is noted in different systems. In the case with imbalance netting, only activation in one direction is applied and the remaining deviation is distributed to some of the TSOs in a pro-rata manner.

Average weighted prices for aFRR activated energy are taken from the questionnaires. In the case of data gaps, **aFRR prices** have been determined in correlation with wholesale prices → **with coefficient of 1.8 for upward regulation and 0.1 for downward regulation**.

In the case of the unavailability of the wholesale prices, the same correlation is applied with respect to average energy weighted for specific operating costs of a thermal cluster for the respected system.

On the basis of the data provided in questionnaires and additional estimations, the proposed average weighted prices for aFRR activated energy that are applied to calculate the imbalance netting benefits are presented in the following table.

Country	Upward regulation price ($/MWh)	Downward regulation price ($/MWh)
Armenia	60.8	3.4
Bulgaria	65.0	3.6
Georgia	98.3	5.5
Moldova	107.5	6.0
Romania	69.0	0.6
Turkey	93.1	5.2
Ukraine	64.8	3.6

Table 3.5 – Average Balancing Prices

Although there are obvious savings for all participants in the imbalance netting cooperation, distribution of savings among participants is a difficult task. With the aim to solve this question, the energy volume supplied to the BE receiving area by the BE providing area shall be given a value based on the amount of costs saved by avoiding the use of control energy in all control areas through balancing (opportunity costs). According to the GCC practice, imbalance settlement price is calculated as the average of all opportunity prices within the respective cooperation, weighted with the respective exchanged volumes of balancing energy per TSO.

In case of a "positive" aFRR request, balancing energy is needed by the TSOs → the opportunity price corresponds to the quotient of avoided energy costs/energy volume, for positive activated aFRR per settlement period.

In case of a "negative" aFRR request, balancing energy can be provided by the TSOs → the opportunity price corresponds to the quotient of avoided energy costs/energy volume, for negative activated aFRR per settlement period.

At imbalance netting, each MWh acquired, as well as delivered by a participant within the same settlement period, is invoiced at the same settlement price. The settlement price is calculated as the volume-weighted average of the opportunity prices, based on the opportunity costs of the participating TSOs. This means that the energy volumes delivered and acquired for each TSO are multiplied by the corresponding opportunity prices, after which the opportunity costs determined in that manner are summed. To determine the settlement price, the sum of the opportunity costs is then divided by the total volume of positive and negative deliveries of energy:

$$\text{Imbalance Settlement Price}$$
$$\text{Opportunity price (negative aFRR)} * \text{Volume delivered (per TSO)} +$$
$$\text{Opportunity price (positive aFRR)} * \text{Acquired volume (per TSO)}$$

For imbalance settlements, the following example is given of three different opportunity costs:

- TSO1 has 55 EUR/MW upward opportunity price
- TSO2 has 20 EUR/MW downward opportunity price
- TSO3 has 10 EUR/MW downward opportunity price

Imbalance netting settlement price is calculated according to the weighted average of opportunity costs for the following requests for activations:

- TSO1 has 100 MW upward activation request
- TSO2 has 60 MW downward activation request
- TSO3 has 20 MW downward activation request

With imbalance netting (and no congestion), the TSO1 would activate an upward aFRR for 20 MW while TSO2 and TSO3 will not activate their reserve at all.

The savings would be calculated in the following manner:

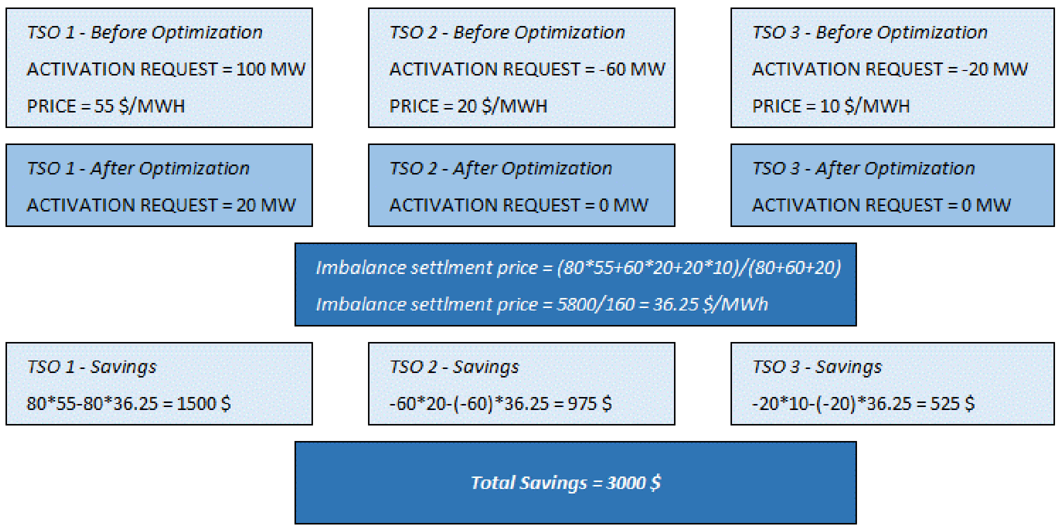

Figure 3.11 Savings Calculated for the Example

Following the current BSRI activities focused on balancing market regulatory development (in Armenia, Georgia, Moldova and Ukraine), an additional sensitivity analysis has been performed taking into account a different set of assumptions concerning the level of average balancing prices (Table 3.6). These figures are based on production cost data collected from the power generation utilities and in comparison with the classical "market based approach" presented before, this data is used for "cost based" analysis.

Country	BSTP Assumptions		BSRI Calculations	
	Upward Regulation Price ($/MWh)	Downward Regulation Price ($/MWh)	Upward Regulation Cost ($/MWh)	Downward Regulation Cost ($/MWh)
Armenia	60.8	3.4	41.37	6.90
Georgia	98.3	5.5	46.87	7.81
Moldova	107.5	6	43.24	7.21
Ukraine	64.8	3.6	42.00	7.00

Table 3.6 – BSTP and BSRI Average Balancing Prices for Armenia, Georgia, Moldova and Ukraine

Details of cost calculations and assumptions are presented in Section 5.3.

3.2.4 Exchange of Balancing Energy over Common Merit Order List (CMO)

For the purpose of the benefits assessment of the exchange of balancing energy over a common merit order list, both upward and downward balancing bids are necessary. This data is usually strictly confidential and is not provided by the questionnaires. Therefore, the developed balancing bids took into account the following:

a) With respect to technical and economic parameters of observed systems, and using the practice from European markets, market bids for balancing energy are estimated in correlation to the wholesale electricity prices at the commercial market level or as previously mentioned, in correlation with energy weighted specific operating costs of the thermal cluster.

b) Bidding curves of balancing bids for upward secondary regulation are defined in the following manner:

   - Bid prices for each step are given in ascending order, ranging from 140% to 240% of wholesale electricity market price in the observed area, with price an increase of 0.2 ratio to wholesale electricity market price per each step
   - Bid quantity is the same for each step and at the level of 20% of defined upward balancing (aFRR or mFRR/RR) reserve in that area

c) Bidding curves of balancing bids for downward secondary regulation are defined in the following manner:

   - Bid prices for each step are given in descending order in range from 10% to 0% of wholesale electricity market price in the observed area, with price decrease of 0.02 ratio to wholesale electricity market price per each step
   - Bid quantity is the same for each step and at the level of 20% of defined downward balancing (aFRR or mFRR/RR) reserve in the area

d) Bidding curves of balancing bids for upward tertiary regulation are defined in the following manner:

   - Bid prices for each step are given in ascending order in a range from 0% to 300% of wholesale electricity market price in the observed area, with a price increase of 0.3 ratio to wholesale electricity market price per each step
   - Bid quantity is the same for each step and at the level of 10% of defined upward balancing (aFRR or mFRR/RR) reserve in that area

e) Bidding curves of balancing bids for downward tertiary regulation are defined in the following manner:

- Bid prices for each step are given in descending order in a range from 150% to 0% of wholesale electricity market price in the observed area, with price decrease of 0.15 ratio to wholesale electricity market price per each step
- Bid quantity is the same for each step and at the level of 10% of defined downward balancing (aFRR or mFRR/RR) reserve in the area

In order to examine the quality of the assumptions, the simulation was checked on the isolated balancing market of Romania, with proposed ratios for balancing bids. The cost for a provision of balancing energy (both aFRR and mFRR/RR) from the obtained simulation results are in the 7% range when compared to the actual realized cost in the analyzed period (2015), as given in the questionnaire. Although roughly estimated, the defined market bids are perceived as sufficiently representative to produce the order of measure in terms of benefits of common usage of balancing energy at the regional level.

Following the wholesale electricity market prices or weighted specific operating costs of the thermal cluster, the following are used as a benchmark:

- Armenia 33.8 $/MWh
- Bulgaria 36.1 $/MWh
- Georgia 54.6 $/MWh
- Moldova 59.7 $/MWh
- Romania 38.0 $/MWh
- Turkey 51.7 $/MWh
- Ukraine 36.9 $/MWh

Common merit order lists (CMO) for both provision of aFRR and mFRR/RR balancing energy, are created on the principle of aggregating bids from all market areas while assuming available CZC. When simulating balancing market behavior, the pay as bid principle is respected in terms of calculation of balancing costs.

Due to unavailability of data regarding activation of aFRR and/or mFRR, engaged secondary and tertiary control energy was estimated on the basis of the available secondary/tertiary control energy dataset of Romania and the coefficient ratio between current levels of corresponding control reserve in Romania and in related countries and monthly consumption from 2015 (see section 4.1). The direction has been determined randomly in order to simulate non-synchronicity of activations in both directions (upward and downward).

These benefits also include the netting concept, a reduction of the engaged balancing energy and the remaining imbalance activation of the cheapest balancing energy sources according to the common merit order list.

4 INPUT DATA AND ASSUMPTIONS

There are several available sources which are used in order to collect and systematize input data. One of them is a small data base created based on questionnaires which were sent to both participating BSTP TSOs and BSRI national regulators (in coordination with NARUC).

Each BSTP member's questionnaire consists of two Excel files, including the following content:

a) **TSO Excel file** which contains the following sheets:
   1. **Historical Hourly Load Data for 2015** (special attention was paid to PHS/pumps which consumption should be excluded from these figures)
   2. **Historical Hourly Generation Data for 2015**
   3. **Load Forecast Data for 2020 in GWh** (given by different consumption groups) and in comparison with 2015
   4. **General Power Plant Data** taken from the PSS/E – OPF model (for checking and update)
   5. **Hydro Power Plant Data** (there was an example of data provision which should be used to organize data from *General Power Plant Data* sheet for existing and new plants, plant by plant, and collect said data concerning technical and economic parameters)
   6. **Thermal Power Plant Data** (there was an example of data provision which should be used to organize data from *General Power Plant Data* sheet for existing and new plants, plant by plant, and collect said data concerning technical and economic parameters)
   7. **Wind Data** – Total installed capacities (2020) and hourly capacity factor for whole year
   8. **Solar Data** – Total installed capacities (2020) and hourly capacity factor for whole year
   9. **Area Control Error Data** – Open Loop ACE (in MW) as two-second measurements for 24 hours on 21.01.2015 (third Wednesday in January 2015)
   10. **Activated Secondary Control Data** for 2015 – hourly (8760) measurements in MW
   11. **Activated Tertiary Control Data** for 2015 – hourly (8760) measurements in MW
   12. **Balancing Market Prices** – Average monthly balancing capacity and balancing energy prices for:
       - Secondary reserves for upward and downward
       - Tertiary reserves for upward and downward

b) **Regulator Excel file** which contains the following sheets:
   1. **Tariff's Data 1** – Information about transmission tariffs, losses, value of loss of load and CO2
   2. **Tariff's Data 2** – Information about renewable feed-in tariffs, pricing policy and tariff system and IPP contract tariffs (if any)
   3. **Market Prices** – Whole sale prices (average monthly: base load & peak load),
   4. **Balancing Energy** – the same data as in the *Balancing Market Prices* for the TSO's questionnaire.

Taking into account varying authorities which participate in the data collection process (national TSOs with different departments and representatives of national regulatory agencies) as well as the obvious complexity of the questionnaires, a certain prioritization of tasks was needed during the first phase of input data systematization. Although some data can be easily collected or verified, it doesn't mean it is the highest priority for this stage of the project. Also, as some of the input data already exists in a PSS/E-OPF format created during previous BSTP studies ([7] and [8]), this study focused on the following:

- Area Control Error (ACE)

- Activated Secondary Control
- Activated Tertiary Control
- Balancing Market Prices

The rest of the data is primarily dedicated to the creation of GTMax model (Chapter 3.2.2).

- Historical hourly load data which is necessary to create the load profile;
- Technical and economic parameters for all types of generation (thermal, hydro and RES). Data sets for each generation type are different and include historic data (e.g. hydro generation per plant for average hydrology) or the data that refers to new, planned sources to be built before 2020, as well as representative hourly time series of relevant RES generation (per plant). For all conventional sources (both, old and new) these parameters include: maximum and minimum capacities of the unit, efficiency, fuel prices assumed for 2020, maintenance and forced outage rates (MOR and FOR). The all-time series (hydro or RES) together with efficiency and outage rates (MOR and FOR) are not included in data sets available in the OPF model and should be collected or assumed.

The following table describes the final status of BSTP TSOs' collected data.

	Armenia	Bulgaria	Georgia	Moldova	Romania	Turkey	Ukraine
Hourly Load	Collected	Collected	Not available	Collected	Collected	Collected	Collected
Hourly Generation	Collected	Collected		Collected	Collected	Not available	Collected
Load Forecast Data	Collected	Not available		Collected	Collected		Collected
General Power Plant Data	Collected	Collected		Collected	Collected		Collected
Hydro Power Plants	Collected	Not available		Collected	Collected		Collected
Thermal Power Plants	Not available	Not available		Collected but some of data is not available (efficiency, fuel prices, CO2 emissions, fixed/variable costs, MOR and FOR)	Collected		Collected (NPPs' data only missing) but some of data is not available (efficiency, fuel prices, CO2 emissions, fixed/variable costs, MOR and FOR)
Wind	Not available	Not available		Not available	Collected		Collected
Solar	Not available	Not available		Not available	Not available		Collected
Area Control Error	5 sec values are available for 19.04.2017. for HPP Tatev active power	Not available		Not available	Collected		5 sec values are available

Activated Secondary Control	Hourly data for period May 2015 – May 2016 are available	Collected		Not available	Collected		Collected
Activated Tertiary Control Data	Not available	Collected		Not available	Collected		Only hourly data for last 20 days are available (26.02.-22.3.2017.)
Balancing Market Prices	Not available	Not available		Not available	Collected		Not available

Table 4.1 – BSTP Collected Data

As expected, a majority of the missing inputs were addressed in regards to the specific balancing market data concerning the activated secondary and tertiary control as well as ACE. As already mentioned in Chapter 3.2.3, in case of data gaps, 2 second values for ACE have been created randomly (as explained in Section 4.1.1. Similarly, based on available data and random distribution of symmetrical activation, both, secondary and tertiary control reaction was estimated (Section 4.1.2).

The next group of missing inputs was primarily dedicated to the operational data for thermal power plants and these values were determined on the basis of the available data through the previous studies and expert views. A similar approach was used for missing load and RES hourly profile.

A complete pool of input data for Georgia and Turkey was not available and the information gathered is a result of corresponding officially published development plans and data collected from official TSO websites' databases.

The planned RES development of Ukraine was collected through questionnaires and was extended by using relevant information from the actual network development plan, particularly concerning forecasted regional wind and solar capacities.

4.1 Lack of Data and Applied Back-up Solution

This chapter describes the approaches that are applied to estimate potential values of Area Control Errors (ACEs) and potential activations of balancing reserves (FRR/RR). Potential values are estimated on the basis of the submitted data (for RO and partially for UA) and correlations between these values and system characteristics.

4.1.1 Estimation of ACE Values

To estimate the potential values of ACEs, the submitted data for Romania and Ukraine included data submitted as 2 seconds measurements for one day in January 2015 (January 21st). To estimate the ACE values for power system correlations between mean values and standard deviations, ACEs and K-factors[17] of each power system were used. The mean values and standard deviations were defined in the following manner:

$$\mu_{ACEi} = \mu_{ACE\text{-}RO} * \mathbf{P}_i / \mathbf{P}_{RO} \text{ and } \mu_{ACEi} = \mu_{ACE\text{-}UA} * \mathbf{P}_i / \mathbf{P}_{UA}$$

$$\sigma_{ACEi} = \sigma_{ACE\text{-}RO} * \sqrt{\mathbf{P}_i / \mathbf{P}_{RO}} \text{ and } \sigma_{ACEi} = \sigma_{ACE\text{-}UA} * \sqrt{\mathbf{P}_i / \mathbf{P}_{UA}}$$

[17] Ki [MW/Hz] is a frequency bias of the control area called K-factor. The K-factor can be viewed as a contribution coefficient, i.e. how much a particular area contributes to the joint action of the primary frequency control in the entire interconnected area.

The K-factors of the individual control areas are calculated from annual net productions Pi of the control areas and Ptotal where Ptotal is the total annual net production in the whole synchronous area [9]:

Ki = Pi/Ptotal * Ktotal

Ratios between K-factors for two areas then can Ki / Kj = Pi / Pj and this ratio has been used for estimation of mean values and standard deviations.

The estimation of the potential values of ACEs for Bulgaria and Turkey is based on ACE data for Romania while the estimation of the potential values of ACEs for AM, Georgia and Moldova is based on ACE data for Ukraine.

The calculated mean values (μ_{ACEi}) and standard deviation (σ_{ACEi}) of the estimated potential values of ACEs are given in the table below.

Country	μ_{ACEi} (MW)	σ_{ACEi} (MW)
Armenia	0.3	18.5
Bulgaria	1.4	52.8
Georgia	0.4	21.8
Moldova	0.2	16.0
Romania	1.8	60.4
Turkey	7.6	117.5
Ukraine	6.1	83.3

Table 4.2 – Calculated Mean Values and Standard Deviation of Potential ACE Values

When calculating mean values and standard deviations and ACE data for Romania and Ukraine, the estimated values of ACEs were determined implementing random distribution. These ACE values were used to assess the potential benefits of cross-border imbalance netting.

4.1.2 Estimation of Values of Secondary and Tertiary Reserves Activation

In order to estimate the potential values of secondary and tertiary reserve activation, Romania submitted data as average hourly activation for 2015. In order to estimate the activations for other power systems, correlations between total imbalance (total activated reserve) and annual consumption were taken into account [18] as well as the level of balancing reserves implemented in each system. In order to further refine estimated values of reserves activations, activations were estimated separately for each month, with the aim to take into account seasonal characteristics of load and, consequently, imbalances.

Finally, two sets of average hourly activations for the whole year for each system were estimated, one set for aFRR activation and the other for mFRR/RR activation. These sets were used to calculate the potential benefits of cross border exchange of balancing energy with implementation of the common merit order list.

The balancing market report for Romania [19] and its submitted data shows that activated reserves (traded energy on balancing market) present 8.2% of total consumption in 2015. This share can be considered as rather high in comparison with shares of [18] available data for Serbia, but it could be the consequence of high RES generation in Romania. Taking this into account, as well as low RES penetration in 2015 in other analyzed power systems, the estimation of reserves activation as a share of 4% was applied for all systems with a distribution of 1.5% to activation of aFRR and 2.5% to activation of an mFRR/RR. Only one exemption has been applied, for Bulgaria, with the aim to take into account data submitted within the questionnaire: 2.5% has been applied for activation of aFRR and 1.5% for mFRR/RR.

Based on the above considerations, the estimated activations have been generated with random distribution assuming symmetrical activations of aFRR (upward and downward). The total annual activations are presented in the following table.

Annual activation		aFRR	mFRR/RR
AM	Upward regulation [GWh]	51	114
	Downward regulation [GWh]	50	56
BG	Upward regulation [GWh]	429	500
	Downward regulation [GWh]	431	1004
GE	Upward regulation [GWh]	83	186
	Downward regulation [GWh]	83	90
MD	Upward regulation [GWh]	45	109
	Downward regulation [GWh]	45	52
RO	Upward regulation [GWh]	543	3014
	Downward regulation [GWh]	590	842
TR	Upward regulation [GWh]	1990	4482
	Downward regulation [GWh]	1986	2114
UA	Upward regulation [GWh]	1115	2516
	Downward regulation [GWh]	1110	1215

Table 4.3 – Annual Activations

4.2 Cost-Based Approach for the Assessment of Benefits of Cross-Border Balancing Cooperation between BSRI Countries

Pricing ancillary services in an electricity market requires an effective market structure with sound performance. In the Black Sea region, some electricity markets are in a transitional phase and are not yet ready to support market based balancing and ancillary services. Therefore, during this transitional period, the BSRI suggests a cost based approach as an interim solution.

The market–based approach considered in the BSTP project will essentially give indications about the sub-regional benefits of the countries from coupling of ancillary services in the long run when competitive markets will be developed at Armenia, Georgia, Moldova, and Ukraine. In addition, BSTP project not only focuses on Armenia-Georgia and Moldova-Ukraine sub-regions but also other sub-regions in which competitive wholesale markets have developed (e.g., Bulgaria, Romania and Turkey sub-region). However, pricing ancillary services in an electricity market requires an effective market structure with sound performance. In the Armenia-Georgia and Moldova-Ukraine sub-regions, prospective electricity markets are not yet ready to support competitive balancing and ancillary services. Therefore, it is not advisable to move directly to market-based pricing of balancing and ancillary services in those countries. This is also emphasized in the BSRI Wholesale Market Guidelines.

For generating resources, the cost of providing balancing and ancillary services is essentially the cost of supplying generation which is divided into two main categories. The first type is for "capacity" cost (fixed), which is used to supply reserve-based ancillary services (primary reserves, secondary reserves, etc.). The second type of generation cost is "running" costs, which are sometimes referred to as "variable" costs associated with "activating" the reserves upward/downward in real-time.

It is recommended to calculate true costs of balancing capacity and activation of reserves based on fixed and variable costs of the power plants. These costs are estimated by the TSOs in the BSTP project to calculate the benefits of sharing reserves and integrating a balancing market through interconnection lines between the BSRI countries. However, those assumptions made in the BSTP project are based on a competitive market condition which includes competitive balancing service providers and do not reflect the current situation in the BSRI countries (Armenia, Georgia, Moldova, and Ukraine). Hence, to be able to calculate the benefits based on the current situation, a different set of cost values should be defined. In this regard, and also as it is recommended that these calculations should be performed by the NRAs, a questionnaire in an MS Excel file format is developed by EPRA and disseminated to the NRAs of Armenia, Georgia, Moldova, and Ukraine. Details of the questionnaire, data collection by the NRAs and calculations of balancing service costs are described in the following Section.

4.2.1 Plant Technical and Cost (Commercial) Data

The scope of the commercial data questionnaire study is to calculate costs of balancing reserve and activation of balancing energy of the most prevailing power plants based on their fixed and variable costs. Parameters considered in calculating fixed and variable costs of the power plants are summarized in Table 4.4.

Fixed Costs	Variable Costs
Plant Type	Plant Type
Plant Installed Capacity (MW)	Plant Installed Capacity (MW)
Plant Minimum Generation (MW)	Plant Minimum Generation (MW)
Initial Investment Cost ($)	Average Annual Energy Generation (MWh)
Installed Year	Annual Cost of Operation ($)*
Economical Life (Years)	Annual Cost of Fuel ($)
Weighted Annual Cost of Capital (WACC) (%)	
Annual Capacity Costs ($)**	

Table 4.4 – Fixed and Variable Costs Considered in Calculating Balancing Reserve Allocation and Activation Costs

The input table mainly focuses on technical parameters of power plants as well as the investment and operational costs. The requested information is:

- Plant type: Gas CC/CP, coal, etc.
- Installed year: The year plant got into service
- Plant installed capacity and max/min generation level: Technical parameters
- Economic life time: Economic life time expectation for Book Value calculation
- WACC: Weighted Average Cost of Capital
- Annual average energy generation: Total energy expected to be generated by the plant
- Initial investment cost: Total cost of investment
- Annual capacity costs: The costs of maintaining physical productive units even when they are not operating
- Annual cost of operation: Taxes, maintenance, overheads and any other cost (excluding fuel) that change when the unit output changes.
- Annual Cost of fuel: Total annual fuel cost

The questionnaire inquires data on the most prevailing power plants in each technology cluster, aiming to use the data to estimate average costs in different technology clusters. The data on hydraulic power plants (HPP) and renewable energy sources (RES) are not solicited as marginal costs of HPPs. RESs are assumed to be zero as they have a priority in the merit order list[18].

4.2.2 Proposed Methodology to Calculate Balancing Costs

The flowchart of the methodology to calculate costs of balancing capacity and activation of reserves is presented in Figure 4.1 and Figure 4.3. The flowcharts present how the data indicated in Section 4.2.1 are utilized for calculating true costs of the power plants for balancing capacity and reserve activation. Definitions and formulations of key financial parameters including depreciation expense, rate on/of return, net book value (NBV), etc., which are utilized in the proposed calculations, are taken from BSRI Wholesale Market Guidelines[19].

Calculations of costs of balancing **capacity** ($/MW) are explained step by step as follows ():

[1]. Initial step is to validate the input data by benchmark studies and ranges for investment cost per kW ($/kW) and annual capacity cost per kW per year ($/kW – yr). The data that is out of the expected range is checked and updated if necessary.

[2]. The **Depreciation Expense (Return of Investment)** is calculated as follows:

Annual Capacity Costs + (Investment Cost / Economical Life)

[3]. Using the **Depreciation Expense**, the **Net Book Value** is calculated as follows:
Investment Cost – ((Depreciation Expense – Annual Capacity Costs) x Years in service)

[4]. The **Return on Investment** is calculated as: (**Net Book Value) x WACC**

[5]. The **Capacity Cost** per MW ($/MW) is then calculated as follows:

(Return on Investment + Depreciation Expense) / Installed Capacity

[6]. In order to convert the total **Capacity Cost** to average capacity cost, average in-service hours are estimated based on the annual energy expectation of the plant and average generation capability while the unit is in-service:

- **In-Service Hours = Annual Energy Generation / average (Pmax,Pmin)**
- **Percentage In-Service Hours (%) = Annual Energy Generation / average (Pmax,Pmin) / 8760**

[18] Inception Report: Analysis of the Potential to Provide Cross-Border Balancing Services and Energy in the Black Sea Region, Black Sea Regional Transmission Planning Project (BSTP) Sub-Agreement: USEA/USAID – 2017 – 708 – 01, 2017.

[19] BSRI Wholesale Market Guidelines for Black Sea Electricity Market Integration, Dec. 2016 (by USAID and NARUC under BSRI).

[7]. The total **Capacity Cost** is split in to two parts:

- The first part: **Capacity Cost** to be compensated while the unit is in service, i.e.:

  Capacity Cost x Percentage In-Service Hours

- The second part: rest of the **Capacity Cost,** i.e.:

  Capacity Cost x (1-Percentage In-Service Hours)

- As the secondary frequency control can only be performed while the unit is in-service, the cost of secondary reserve capacity is calculated as ($/MW-hr):

  Capacity Cost x Percentage In-Service Hours / In-Service Hours

- As tertiary frequency control can be performed in dependent of the units service status, the cost of tertiary reserve capacity is calculated as ($/MW-hr):

  Capacity Cost x (1-Percentage In-Service Hours) / 8760

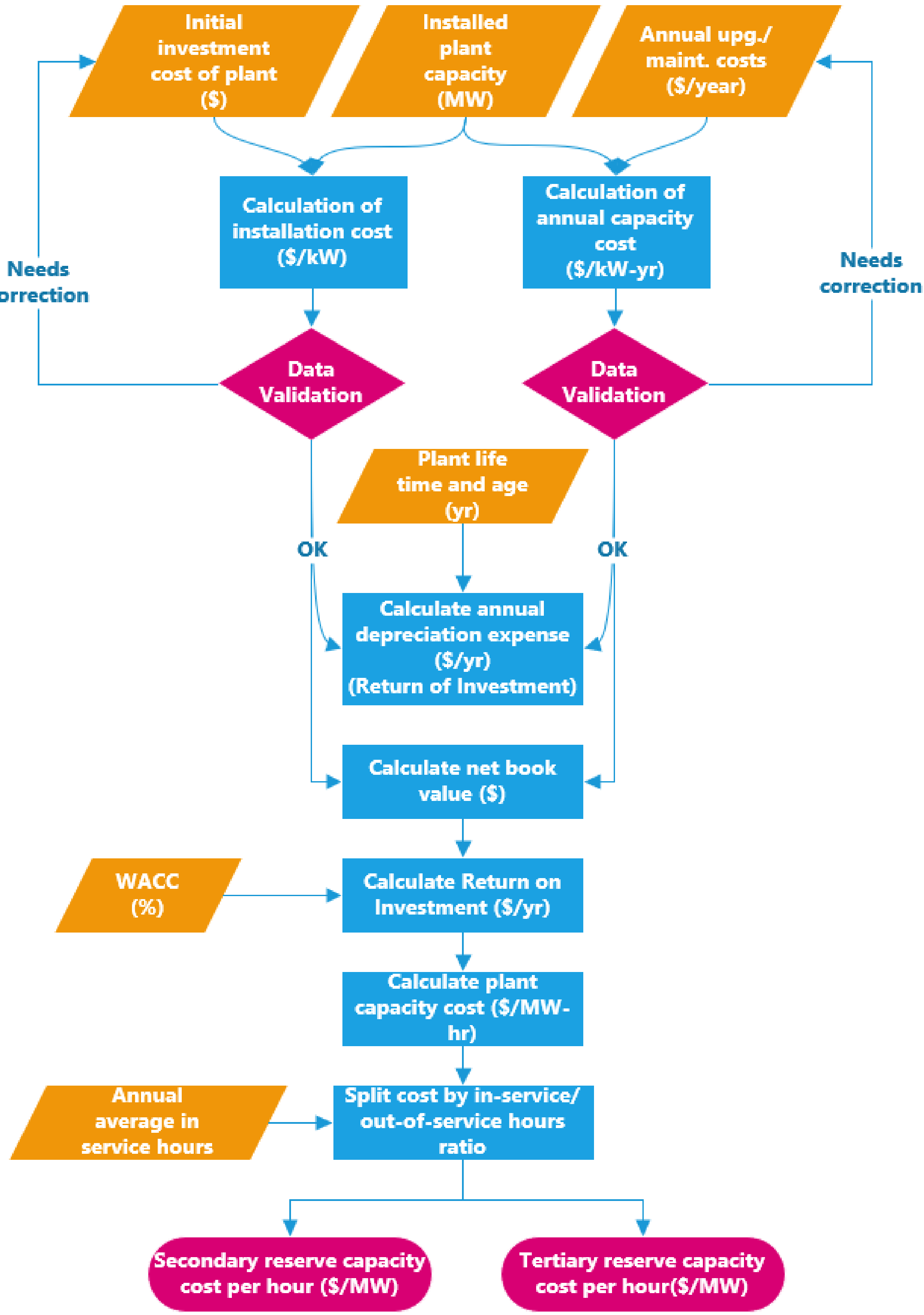

Figure 4.1 – Flowchart of the Methodology to Calculate Costs of Balancing Capacity

Calculation of costs of **activation of reserves** (upward/downward $/MWh) is explained step by step as follows:

[1]. Initial step is to validate the input data through benchmark studies and ranges for operation and fuel costs ($/year). The data that is out of the expected range is checked and feed back to NRAs but is not changed for the studies.

[2]. Total variable cost in is converted average cost ($/MWh) utilizing the annual average generation of power plants.

[3]. The characteristics of up/down regulation prices/costs are different in the market-based and cost-based approaches, as described below:

- For the market-based approach, the power plants which are subjected to downward regulation, are already paid at market clearing price in the day-market. In such competitive markets, the market players bid much higher for their additional generation (upward activation of energy) than they pay for generation reduction (downward activation of energy).
- However, in a cost-based approach, there is no bid from the power plants for downward activation of reserves. Downward regulation introduces savings from the costs calculated in day-ahead, whereas upward regulation introduces additional costs. Hence, the cost difference between up/down regulation is relatively much smaller with respect to the market-based approach as illustrated in the following figure. Based on this fact, the upward and downward regulation costs are assumed to be 120% and 80% of the calculated operating costs, respectively, in the proposed cost-based approach.

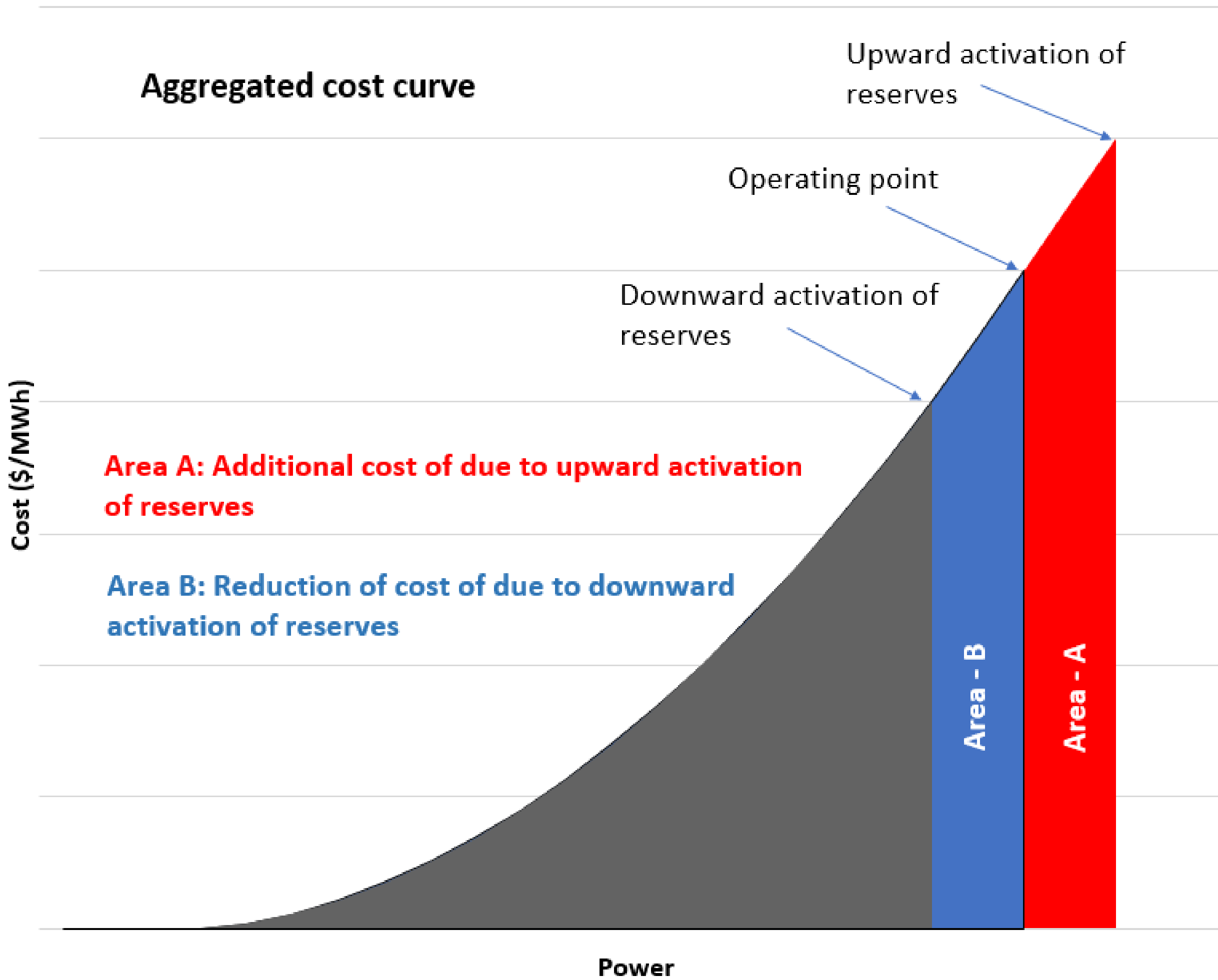

Figure 4.2 Upward/downward Regulation Cost in a Cost-based Approach Calculation.

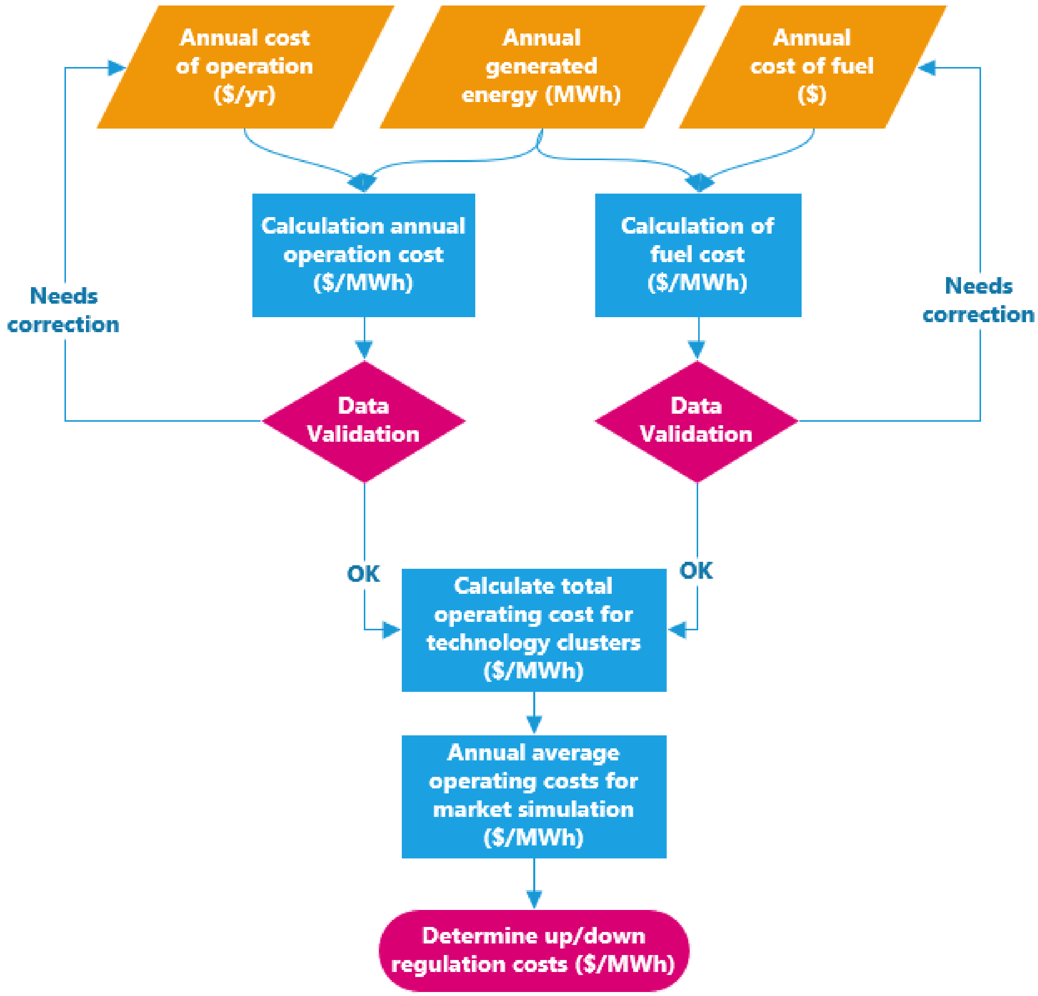

Figure 4.3 Flowchart of the Methodology to Calculate Costs of Activation of Reserves

Before calculating the balancing capacity and reserve activation costs of power plants, a data validation is performed by comparing the collected data with some international benchmarking studies that are available in the literature[20,21,22]. After reviewing the commercial data provided by the Armenian, Georgian, Moldovan and Ukrainian regulators, it is observed that some of the data is beyond plausible range (or they require clarification), as indicated in the following tables. Unclear data pertinent to fixed costs of the power plants are corrected by EPRA experts based on the benchmark studies. The NRAs agreed to utilize the corrected fixed cost values in the sensitivity analysis. They also confirmed to utilize variable costs calculated by the aforementioned approach.

[20] Life-Cycle Greenhouse Gas Assessment of Coal and Natural Gas in the Power Sector, Congressional Research Service, June 26, 2015 (http://nationalaglawcenter.org/wp-content/uploads/assets/crs/R44090.pdf)

[21] Capital Cost Estimates for Utility Scale Electricity Generating Plants, U.S. Energy Information Administration (EIA), November 2016 (https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf)

[22] Cost and Performance Assumptions for Modeling Electricity Generation Technologies, NREL, November 2010 (https://www.nrel.gov/docs/fy11osti/48595.pdf)

No	Input Item	Plant	Question - Comment	Proposed Solution
A-1	- Initial investment cost of the plant ($) - Annual upg./maint. costs ($) - Annual cost of operation ($) - Annual cost of fuel ($)	All plants	Provided cost data seems to be too low	Probably excel thousand/decimal seperator error (can be caused by the regional settings of computer operating systems) or a confusion of input unit. The data is utilised after multiplication with 1000.
A-2	Initial investment cost of the plant ($)	Hrazdan TPP	Even after multiplication with 1000, the value is still too low when compared to expected range. This can be due to lack of info as the plant is too old or a problem due to currency conversion. Either way, it is recommended to re-check the value.	For calculation purposes a value for $/kW is assigned for the plant.
A-3	Initial investment cost of the plant ($)	Armenian Nuclear Power Station	Even after multiplication with 1000, the value is still too low when compared to expected range. This can be due to lack of info as the plant is too old or a problem due to currency conversion. Either way, it is recommended to re-check the value.	For calculation purposes a value for $/kW is assigned for the plant.
A-4	Annual upg./maint. costs ($)	Yerevan TPP	The fixed operation and maintenance costs for this plant is quite high. This can be due to a relatively larger refurbishment in the plant that occurred last year. It is recommended to check the previous years costs to see if the cost is in this range for last 3-4 years. If not, reduce the value to create an approximate average annual value.	For calculation purposes a value for $/kW is assigned for the plant.
A-5	Annual cost of operation ($)	All plants	After multiplilcation with 1000 (see item no-1), the values are above the expected rage. This might have various reasons like number of cold/hot starts, utilisation in balancing, utilisation of the plant for heating purposes instead of electricty generation, etc. However, it is recommended to re-check the given values.	For calculation purposes, the parameters provided by the regulator are utilised.

Table 4.5 Review Results of Commercial Data – Armenia NRA

No	Input Item	Plant	Question - Comment	Proposed Solution
G-1	Initial investment cost of the plant ($)	Tbilsresi Mtkvari	The data is missing.	For calculation purposes a value for $/kW is assigned for the plant.
G-2	Average full load hours per year	Tbilsresi Gpower (gas turbine)	The full load hours for given plants are too low. It is recommended to re-check the values.	For calculation purposes, the parameters provided by the regulator are utilised.
G-3	Annual upg./maint. costs ($)	Tbilsresi Mtkvari	The fixed operation and maintenance costs for these plants are quite low. This can be due to a relatively larger refurbishment in the plant that occurred recently. It is recommended to check the previous years costs to see if the cost is in this range for last 3-4 years. If not, increase the value to create an approximate average annual value.	For calculation purposes a value for $/kW is assigned for the plant.
G-4	Annual cost of operation ($)	Tbilsresi Gpower (gas turbine)	The values are above the expected rage. This might have various reasons like number of cold/hot starts, utilisation in balancing, utilisation of the plant for heating purposes instead of electricty generation, etc. However, it is also possible (especially for Tbilsresi) that the fixed and variable O&M costs are grouped with a different approach than intended. Thus, Annual upg./maint. costs are calculated as too low and Annual cost of operation is calculated too high. It is recommended to re-check the given values.	For calculation purposes, the parameters provided by the regulator are utilised.
G-5	Data for Lignite/Coal Plants	-	No data is provided for lignite/coal technology.	-

Table 4.6 Review Results of Commercial Data – Georgia NRA

No	Input Item	Plant	Question - Comment	Proposed Solution
M-1	Initial investment cost of the plant ($)	MGRAS	The data is missing.	For calculation purposes a value for $/kW is assigned for the plant.
M-2	Annual cost of operation ($)	MGRAS	The values are above the expected rage. This might have various reasons like number of cold/hot starts, utilisation in balancing, utilisation of the plant for heating purposes instead of electricty generation, etc. It is recommended to re-check the given values.	For calculation purposes, the parameters provided by the regulator are utilised.

Table 4.7 Review Results of Commercial Data – Moldova NRA

No	Input Item	Plant	Question - Comment	Proposed Solution
1	Initial investment cost of the plant ($)	Old plants	The data is missing.	For calculation purposes a value for $/kW is assigned for the plant.
2	Annual upg./maint. costs ($)		Only aggregated (by plant technology) data exists	Use the agregated data for country wide calculations
3	Annual cost of operation ($)		Only aggregated (by plant technology) data exists	Use the agregated data for country wide calculations
4	Annual cost of fuel ($)		Only aggregated (by plant technology) data exists	Use the agregated data for country wide calculations

Table 4.8 Review Results of Commercial Data – Ukraine NRA

Summary of the power plants and main inputs are presented in Table 4.9. Plausible cost intervals (minimum and maximum limits) are identified based on the literature survey[20][21][22], as illustrated in the table. The results of the balancing capacity and reserve activation cost calculations based on the proposed methodology are presented in Table 4.10, which includes the cost assumptions made in the BSTP project for comparison. Essentially, calculated balancing costs are different than those estimated in the BSTP project with the market-based approach, as illustrated in the comparison figures below (-). This result verifies the necessity of sensitivity analysis for calculating benefit of the countries from common usage of balancing services.

Sensitivity analysis results will show benefits of the countries in a cost-based approach. In addition, they will enable comparison of the benefits calculated by market-based approach and cost-based approach. It is recommended that the NRAs should continue to refine the cost data in a harmonized manner and that other plant data is collected in addition to the most prevailing power plants. Cost-based data could be collected and aligned with the philosophy that calculating net benefits uses true cost data - not the market estimation data - to be more representative of the current market state in the BSRI countries.

Calculation and Comparison of Installation Cost ($/kW)

Plant	Country	Type	Installed Year	Total Capacity (MW)	Literature Minimum Installation Cost ($/kW)	Literature Maximum Installation Cost ($/kW)
Yerevan TPP	Armenia	Gas	2010	205.0	600.0	1,200.0
Hrazdan TPP	Armenia	Gas	1974	750.0	600.0	1,200.0
Hrazdan -5 TPP	Armenia	Gas	2011	440.0	600.0	1,200.0
Armenian Nuclear Power Station	Armenia	Nuclear	1980	380.0	3,500.0	7,000.0
Tbilsresi	Georgia	Gas	1967	272.0	600.0	1,200.0
Mtkvari	Georgia	Gas	1990	300.0	600.0	1,200.0
Gardabani CCGT	Georgia	Gas	2015	231.2	600.0	1,200.0
Gpower (gas turbine)	Georgia	Gas	2006	110.0	400.0	800.0
MGRAS	Moldova	Gas	1964	1,200.0	600.0	1,200.0

Calculation and Comparison of O&M Cost - Fixed ($/kW-yr)

Plant	Country	Type	Installed Year	Total Capacity (MW)	Literature Minimum Fixed O&M Cost ($/kW-yr)	Literature Maximum Fixed O&M Cost ($/kW-yr)
Yerevan TPP	Armenia	Gas	2010	205.0	600.0	1,200.0
Hrazdan TPP	Armenia	Gas	1974	750.0	600.0	1,200.0
Hrazdan -5 TPP	Armenia	Gas	2011	440.0	600.0	1,200.0
Armenian Nuclear Power Station	Armenia	Nuclear	1980	380.0	3,500.0	7,000.0
Tbilsresi	Georgia	Gas	1967	272.0	600.0	1,200.0
Mtkvari	Georgia	Gas	1990	300.0	600.0	1,200.0
Gardabani CCGT	Georgia	Gas	2015	231.2	600.0	1,200.0
Gpower (gas turbine)	Georgia	Gas	2006	110.0	400.0	800.0
MGRAS	Moldova	Gas	1964	1,200.0	600.0	1,200.0

Calculation and Comparison of O&M Cost - Variable ($/MWh)

Plant	Country	Type	Installed Year	Total Capacity (MW)	Literature Minimum Variable O&M Cost ($/MWh)	Literature Maximum Variable O&M Cost ($/MWh)
Yerevan TPP	Armenia	Gas	2010	205.0	2.0	6.0
Hrazdan TPP	Armenia	Gas	1974	750.0	2.0	6.0
Hrazdan -5 TPP	Armenia	Gas	2011	440.0	2.0	6.0
Armenian Nuclear Power Station	Armenia	Nuclear	1980	380.0	0.3	3.0
Tbilsresi	Georgia	Gas	1967	272.0	2.0	6.0
Mtkvari	Georgia	Gas	1990	300.0	2.0	6.0
Gardabani CCGT	Georgia	Gas	2015	231.2	2.0	6.0
Gpower (gas turbine)	Georgia	Gas	2006	110.0	2.0	6.0
MGRAS	Moldova	Gas	1964	1,200.0	2.0	6.0

Calculation and Comparison of Fuel Cost - Variable ($/MWh)

Plant	Country	Type	Installed Year	Total Capacity (MW)	Literature Minimum Variable Fuel Cost ($/MWh)	Literature Maximum Variable Fuel Cost ($/MWh)
Yerevan TPP	Armenia	Gas	2010	205.0	20.0	60.0
Hrazdan TPP	Armenia	Gas	1974	750.0	20.0	60.0
Hrazdan -5 TPP	Armenia	Gas	2011	440.0	20.0	60.0
Armenian Nuclear Power Station	Armenia	Nuclear	1980	380.0	5.0	20.0
Tbilsresi	Georgia	Gas	1967	272.0	20.0	60.0
Mtkvari	Georgia	Gas	1990	300.0	20.0	60.0
Gardabani CCGT	Georgia	Gas	2015	231.2	20.0	60.0
Gpower (gas turbine)	Georgia	Gas	2006	110.0	30.0	80.0
MGRAS	Moldova	Gas	1964	1,200.0	20.0	60.0

Table 4.9 Assessment Results of the Commercial Data Provided by Armenian, Georgian, and Moldovan Regulators

Balancing reserve				
	BSTP Assumptions (Market-based approach)		BSRI Calculations (Cost-based approach)	
	Secondary Reserve (aFRR) Price ($/MW)	Tertiary Reserve (mFRR/RR) Price ($/MW)	Secondary Reserve (aFRR) Cost ($/MW)	Tertiary Reserve (mFRR/RR) Cost ($/MW)
Armenia	11.6	5.8	9.87	4.46
Georgia	14.8	7.4	10.24	4.60
Moldova	21.3	10.6	3.19	0.88
Ukraine	12.3	6.2	3.17	0.27

Upward/downward regulation of balancing energy				
	BSTP Assumptions (Market-based approach)		BSRI Calculations (Cost-based approach)	
	Upward Regulation Price ($/MWh)	Downward Regulation Price ($/MWh)	Upward Regulation Cost ($/MWh)	Downward Regulation Cost ($/MWh)
Armenia	60.8	3.4	41.37	6.90
Georgia	98.3	5.5	46.87	7.81
Moldova	107.5	6	43.24	7.21
Ukraine	64.8	3.6	42.00	7.00

Table 4.10 Results of the Balancing Capacity and Reserve Activation Cost Calculations

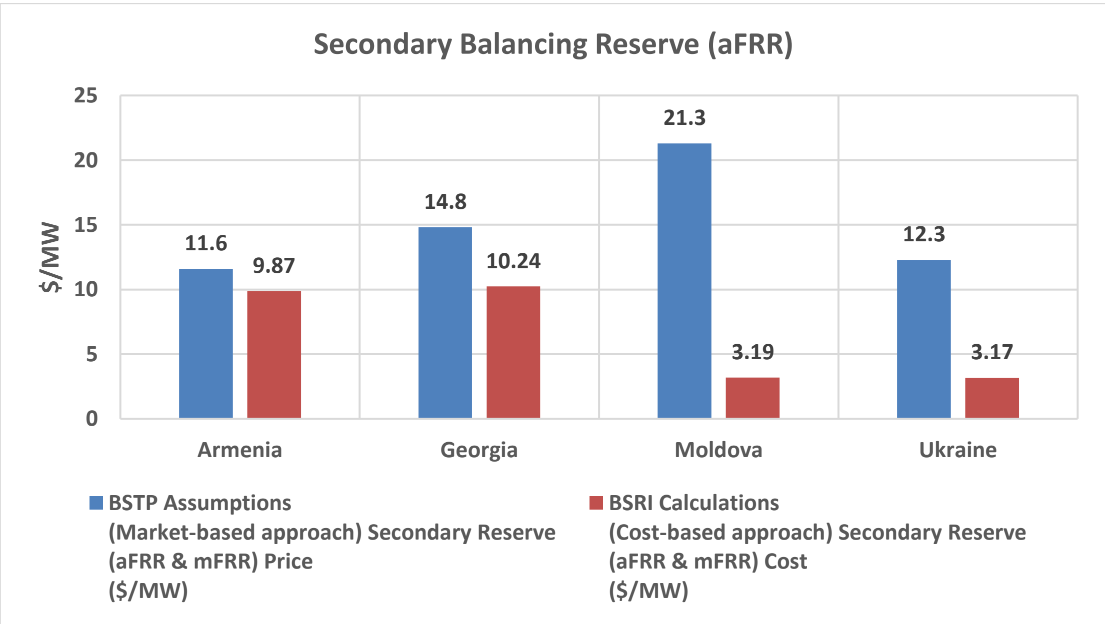

Figure 4.4 Comparison of Market-based and Cost-based Results (Balancing Reserve - Secondary)

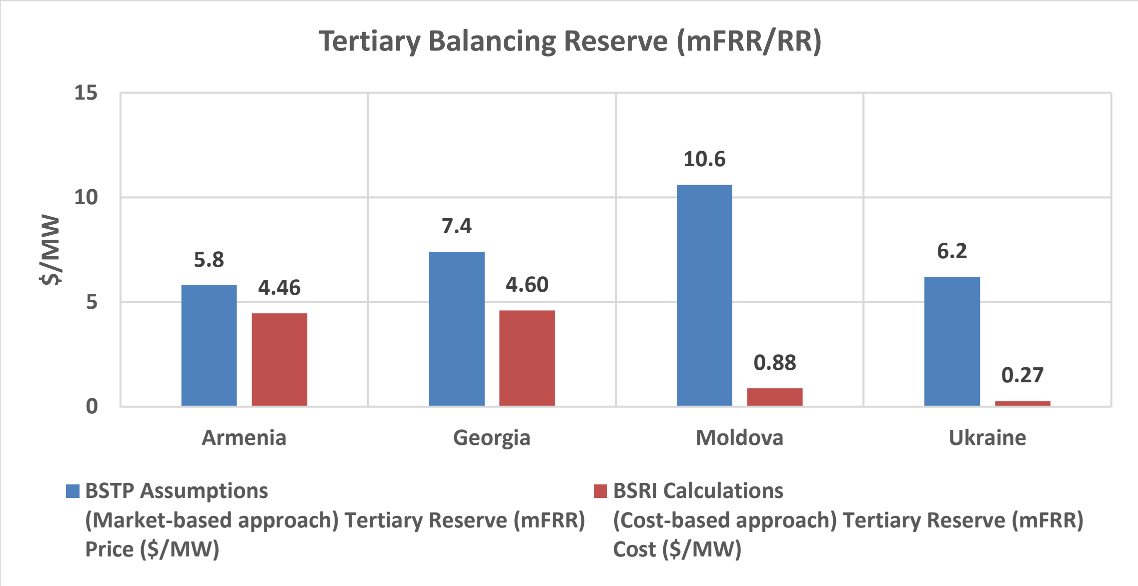

Figure 4.5 Comparison of Market-based and Cost-based Results (Balancing Reserve (Tertiary)

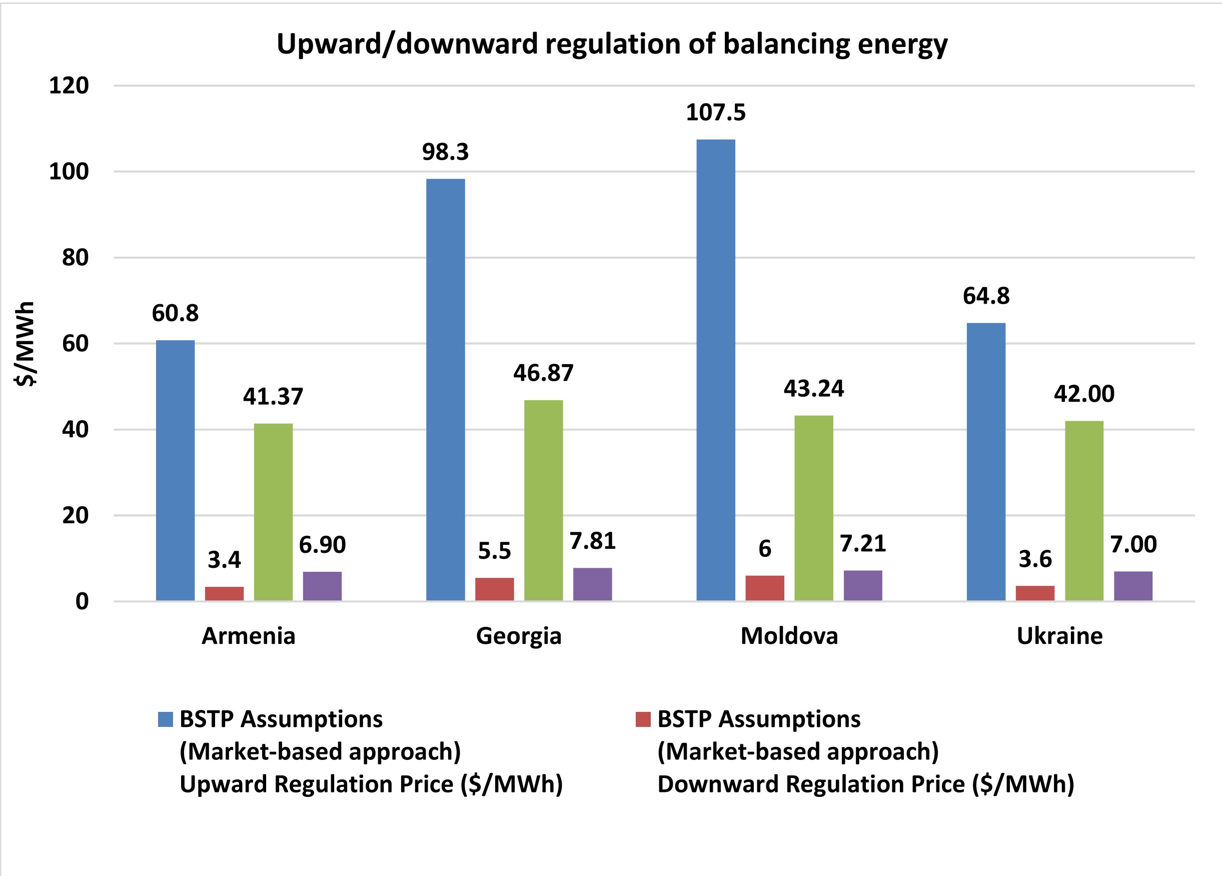

Figure 4.6 Comparison of Market-based and Cost-based Results (Upward/Downward Regulation of Balancing Energy)

5 EVALUATION OF BALANCING MARKET INTEGRATION BENEFITS

Disclaimer

The numerical assessment is done for the observed models of balancing market integration, wherever applicable.

The preformed analyses are based on limited datasets, with assumptions made due to the lack of data.

Due to the low level of development of national balancing markets, certain information listed below does not exist and therefore an increased level of assumptions are applied.

This analyses and its consequent numerical results can only be treated as indicative and exemplary, providing non-binding figures that are an estimation.

As possible follow-up, the detailed analyses can be done for each of the integration models and for each of the observed TSOs, with full datasets available that are related but not limited to:

- Quantities of requested and activated balancing reserve (aFRR, mFRR/RR)
- Offers by BSPs (quantities and prices)
- Transparent information on price determination

Recognizing that the region may require an interim step in its progress toward fully competitive balancing markets, the BSRI recommended that the BSTP Working Group conduct a cost-based sensitivity analysis of the benefits deriving from its market based calculations. Using data provided by BSRI on the cost of balancing services in each country, the BSTP conducted a sensitivity analysis of its market based calculations that provide indications of the benefits of the cross border provision of balancing services in a cost regulated environment. The benefits of introducing different balancing market integration models have been assessed by comparing the costs of all the options with isolated balancing market operations, without the implementation of a integration model. The focus of this analysis is to clearly identify technical and economic benefits of regional (and sub-regional) balancing market integration.

The input datasets reported in this study are primarily based on available data published by TSOs, limited sets of collected data as well as assumptions, as described in Chapter 3. Changes to the input dataset may materially change the outputs. However, these limitations are not expected to have a significant impact on the conclusions drawn below. In addition to the assumed level of balancing reserve prices based on BSTP proxies ("market based approach"), a sensitivity analysis has been conducted taking into account recent BSRI activities and the prices estimated based on information collected from power generation utilities in the countries with undeveloped balancing market ("cost based approach").

Figure 5.1 – Black Sea Sub-regions

The analysis was performed for the following examples of the sub-regional balancing markets integration (they were explained in details within section 3):

- **Sub-region A1**: Armenia and Georgia
- **Sub-region A2**: Georgia and Turkey
- **Sub-region B**: Bulgaria, Romania and Turkey
- **Sub-region C**: Moldova and Ukraine

The analyses performed in this study does not take into account any restrictions of cross-border capacity. Therefore, the estimated benefits can be considered as overestimated. In the process of balancing market integration, one of the tasks for TSOs and regulators is detailing the social-economic benefits of reserving part of the cross-border capacity for real-time balancing and regulating purposes. Looking at different participants in the day-ahead market, this reservation might have a different impact on producers, consumers and the TSOs. Especially for the TSOs, there is a benefit of reserving transmission capacity for reserves in both the day-ahead market and the regulating power market. As the TSOs are operating the links, it would be profitable for them to implement such a capacity reservation but, this reservation could lead to a decrease in the total socio-economic benefit. This calls for an active role of the regulators in order to achieve the best socio-economic outcome.

5.1 Assessment of Common Usage of Balancing Reserve

In this chapter, the benefits of common usage of balancing reserve are evaluated and explained as illustrative examples of real power systems. In addition to the assumed level of balancing reserve prices based on BSTP proxies ("market based approach"), a sensitivity analysis has been conducted taking into account recent BSRI activities and the prices estimated based on information collected from power generation utilities in the countries with undeveloped balancing market ("cost based approach").

5.1.1 Calculation of Direct Benefits of Common Dimensioning of Reserve

As previously described in Chapter 3.1.1, the TSOs that operate within the LFC Block have the opportunity to jointly dimension the total volume of balancing reserve on the level of a common dimensioning incident. As previously mentioned, the prerequisite for this is the availability of the cross-zonal capacity that corresponds to the level of reserve distributed among TSOs within the LFC Block. It is assumed that the examples mentioned above can be observed as unique LFC blocks.

The direct benefits of common dimensioning of the reserve reviewed in the examples of the LFC blocks are quantified when comparing cases with individual TSO dimensioning and with joint dimensioning within the LFC block:

a) **Sub-region A1**:

1. When TSOs perform individual dimensioning, the required reserve capacity results in the following:

   - Armenia: 210 MW /outage of unit 1 in the nuclear power plant
   - Georgia: 320 MW /outage of unit in the thermal power plant
   - Total LFC block: 530 MW

2. When TSOs perform common dimensioning of reserve, the total required reserve in the LFC block results in the following:

   - Armenia: 127 MW
   - Georgia: 193 MW
   - Total LFC block: 320 MW

When comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 40% on the level of the LFC block
- 210 MW of capacity is released for commercial use in the LFC block
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with the considerations described in Chapter 3 and the values presented in Table 3.2, 12 million USD/year would be saved due to a decrease in capacity payment within the LFC block.

b) **Sub-region A2**:

1. When TSOs perform individual dimensioning, the required reserve capacity is the following:

   - Georgia: 320 MW /outage of a unit in the thermal power plant
   - Turkey: 1000 MW /outage of unit I in the thermal power plant
   - Total LFC block: 1320 MW

2. When TSOs perform common dimensioning of reserve, the total required reserve in the LFC block is the following:

   - Georgia: 242 MW
   - Turkey: 758 MW
   - Total LFC block: 1000 MW

When comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 25% at the level of the LFC block
- 320 MW of capacity is released for commercial use in the LFC block
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with the considerations described in Chapter 3 and values as presented in Table 3.2, 22 million USD/year would be saved due to a decrease in capacity payment within the LFC block.

c) **Sub-region B**:

1. When TSOs perform individual dimensioning, the required reserve capacity is the following:

   - Bulgaria: 1040 MW /outage of a unit in the NPP Kozloduy
   - Romania: 1000 MW /outage of a unit in the thermal power plant
   - Turkey: 1000 MW /outage of the biggest unit

- Total LFC block: 3040 MW

2. When TSOs perform common dimensioning of reserve, the total required reserve in the LFC block is the following:

   - Bulgaria: 346 MW
   - Romania: 342 MW
   - Turkey: 342 MW
   - Total LFC block: 1040 MW

When comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 66% at the level of the LFC block
- 2000 MW of capacity is released for commercial use in the LFC block
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with the considerations described in Chapter 3 and values as presented in Table 3.2, 113 milllion USD/year would be saved due to a decrease in capacity payment within the LFC block.

d) **Sub-region C**:

1. When TSOs perform individual dimensioning, the required reserve capacity is the following:

   - Moldova: 210 MW /outage of a unit in the TPP
   - Ukraine: 1000 MW /outage of the largest unit
   - Total LFC block: 1210 MW

2. When TSOs perform common dimensioning of reserve, the total required reserve in LFC block is the following:

   - Moldova: 174 MW
   - Ukraine: 826 MW
   - Total LFC block: 1000 MW

When comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 18% on the level of the LFC block
- 210 MW of capacity is released for commercial use in the LFC block
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with the considerations described in Chapter 3 and values as presented in Table 3.2, 13 million USD/year would be saved due to a decrease in capacity payment within the LFC block.

The application of a **common dimensioning model** of balancing markets integration can give high benefits, achieving savings in total reserve procurement costs of almost 66%. This model of cooperation in common procurement of balancing reserve (capacity) provides the highest benefits. However, in terms of implementation, it is the most difficult as it requires the highest level of harmonization.

Sub-region	Individual Dimensioning [Million USD]			Joint Dimensioning [Million USD]	Savings
	TSO1	TSO2	TSO3		Million USD (%)
A1: Armenia (TSO1) – Georgia (TSO2)	10.6	20.7	-	18.9	12.4 (40%)
A2: Georgia (TSO1) – Turkey (TSO2)	20.7	67.9	-	67.1	21.5 (24%)
B: Bulgaria (TSO1) – Romania (TSO2) – Turkey (TSO3)	46.9	57.0	67.9	58.8	113.0 (66%)
C: Moldova (TSO1) – Ukraine (TSO2)	19.6	54.0	-	60.8	12.8 (17%)

Figure 5.2 Individual Dimensioning, Joint Dimensioning and Resulting Savings (Million USD)

"Cost Based" Sensitivity Analysis

Taking into account the BSRI capacity prices for Armenia, Georgia, Moldova and Ukraine given in Table 3.3 and the same level of balancing capacity that can be reduced through a common dimensioning model for sub-regions A1 and C, the following direct benefits are obtained (figures are in orange in the gray cells):

	Market Based				Cost Based			
Sub-region	Individual Dimensioning		Joint Dimensioning [Million USD]	Savings	Individual Dimensioning		Joint Dimensioning [Million USD]	Savings
	TSO1	TSO2		Million USD (%)	TSO1	TSO2		Million USD (%)
A1: Armenia (TSO1) – Georgia (TSO2)	10.6	20.7	18.9	12.4 (40%)	8.2	12.9	12.7	8.4 (40%)
C: Moldova (TSO1) – Ukraine (TSO2)	19.6	54	60.8	12.8 (17%)	1.6	2.4	3.3	0.7 (17%)

Table 5.1. Summary of Direct Benefits from Common Dimensioning (Market- vs. Cost-based Approach)

As it can be seen, the same saving relative ratios were kept in comparison with so called "market based" approach.

5.1.2 Calculation of Direct Benefits of Sharing of Reserve

Sharing of reserve can be performed among two LFC Blocks when taking into consideration the prerequisites described in Section 3.1.1.

The direct benefits of sharing of reserve for all observed sub-regions and countries is provided as examples of reserve sharing between TSOs (assuming that they are not in the same LFC block as in the previous exercise). Thus, the analysis is performed first without sharing of reserve and second with maximum allowable sharing ratio (defined at 30% of dimensioning incident within LFC block):

a) **Sub-region A1**:

1. When TSOs perform individual dimensioning, the required reserve capacity is the following:
    - Armenia: 210 MW
    - Georgia: 320 MW
    - Total LFC block: 530 MW
3. When TSOs perform maximal sharing of reserve (max 30%), the total required reserve in LFC blocks is the following:
    - Armenia: 185 MW
    - Georgia: 282 MW
    - Total LFC block: 467 MW

Comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 12% at the level of the LFC blocks
- 63 MW of capacity is released for commercial use in the LFC blocks
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that the capacity prices are in line with considerations, as described in Chapter 3 and values as presented in Table 3.2, savings from decrease in capacity payment within LFC block would be at the level of 3.7 million USD/year with pro-rata distribution of total reduction among participating systems.

b) **Sub-region A2**:

1. When TSOs perform individual dimensioning, the required reserve capacity is the following:
    - Georgia: 320 MW
    - Turkey: 1000 MW
    - Total LFC block: 1320 MW
4. When TSOs perform maximal sharing of reserve (max 30%), the total required reserve in LFC blocks is the following:
    - Georgia: 297 MW
    - Turkey: 927 MW
    - Total LFC block: 1224 MW

Comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 7% at the level of the LFC blocks
- 96 MW of capacity is released for commercial use in the LFC blocks
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with the considerations described in Chapter 3 and values as presented in Table 3.2, savings from decrease in capacity payment within LFC block would be at the level of 6.4 million USD/year with pro-rata distribution of total reduction among participating systems..

c) **Sub-region B**:

1. When the TSOs perform individual dimensioning, the required reserve capacity is the following:

   - Bulgaria: 1040 MW
   - Romania: 1000 MW
   - Turkey: 1000 MW
   - Total LFC blocks: 3040 MW

5. When TSOs perform maximal sharing of reserve (max 30%), the total required reserve in the LFC blocks is the following:

   - Bulgaria: 937 MW
   - Romania: 901 MW
   - Turkey: 901 MW
   - Total LFC blocks: 2740 MW

Comparing these two cases, the following benefits are observed:

- Total reserve is reduced by 10% on the level of the LFC blocks
- 300 MW of capacity is released for commercial use in the LFC blocks
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with considerations described in Chapter 3 and values as presented in Table 3.2, savings from the decrease in capacity payment within the LFC blocks would be at the level of 17 million USD/year with pro-rata distribution of total reduction among participating systems.

d) **Sub-region C**:

1. When TSOs perform individual dimensioning, the required reserve capacity is the following:

   - Moldova: 210 MW
   - Ukraine: 1000 MW
   - Total LFC block: 1210 MW

6. When TSOs perform maximum sharing of reserve (max 30%), the total required reserve in LFC blocks is the following:

   - Moldova: 199 MW
   - Ukraine: 948 MW
   - Total LFC block: 1147 MW

Comparing these two cases, the following benefits can be observed:

- Total reserve is reduced by 5% at the level of the LFC blocks
- 63 MW of capacity is released for commercial use in the LFC blocks
- TSOs decrease costs for balancing capacity (reserve) payments. With the assumption that capacity prices are in line with considerations described in Chapter 3 and values as presented in Table 3.2, savings from the decrease in capacity payments within the LFC block would be at the level of 3.8 million USD/year with pro-rata distribution of total reduction among participating systems.

The application of the **reserve sharing model** when integrating balancing markets can result in high benefits such as achieving total reserve procurement savings of 12%. This model of cooperation in terms of common procurement of balancing reserve (capacity) provides lower benefits in comparison with "common dimensioning," but it is less complex for implementation as it doesn't require a high level of harmonization among participating TSOs.

Sub-region	Individual Dimensioning [Million USD]			Joint Dimensioning [Million USD]	Savings
	TSO1	TSO2	TSO3		Million USD (%)
A1: Armenia (TSO1) – Georgia (TSO2)	10.6	20.7	-	27.7	3.7 (12%)
A2: Georgia (TSO1) – Turkey (TSO2)	20.7	67.9	-	82.2	6.4 (7%)
B: Bulgaria (TSO1) – Romania (TSO2) – Turkey (TSO3)	46.9	57.0	67.9	154.8	17.0 (10%)
C: Moldova (TSO1) – Ukraine (TSO2)	19.6	54.0	-	69.8	32.8 (5%)

The presented benefits are calculated with pro-rata distribution of total reserve reduction among participating systems. The distribution of total reduction of balancing reserve with a maximum reduction of more expensive reserve would provide benefits higher than the ones presented in the table above.

The reserve exchange model of balancing markets integration does not change the level of reserve capacity. In case of this model, the benefits would be lower than the benefits presented in the table above while keeping the same level of total reserve procured for the participating TSOs.

Figure 5.3 Individual Dimensioning, Joint Dimensioning and Resulting Savings (Million USD)

"Cost Based" Sensitivity Analysis

Taking into account the BSRI capacity prices for Armenia, Georgia, Moldova and Ukraine given in Table 3.3 and the same level of balancing capacity that can be reduced through a sharing of reserve model for sub-regions A1 and C, the following direct benefits are obtained (figures in orange in gray cells):

	Market Based				Cost Based			
Sub-region	Individual Dimensioning		Joint Dimensioning [Million USD]	Savings	Individual Dimensioning		Joint Dimensioning [Million USD]	Savings
	TSO1	TSO2		Million USD (%)	TSO1	TSO2		Million USD (%)
A1: Armenia (TSO1) – Georgia (TSO2)	10.6	20.7	27.7	3.7 (12%)	8.2	12.9	18.6	2.5 (12%)
C: Moldova (TSO1) – Ukraine (TSO2)	19.6	54	69.8	32.8 (5%)	1.6	2.4	3.8	0.2 (5%)

Table 5.2. Summary of Direct Benefits from Sharing of Reserves (Market- vs. Cost-based Approach)

The same savings relative ratios were kept in comparison with the so called "market based" approach.

5.1.3 Calculation of Indirect Benefits of Reduced Balancing Reserve: Free Generation for Commercial Market

In addition to the direct benefits of the common usage of balancing reserve as observed in the previous two analyses (avoided payments for balancing capacity), the implementation of this process also affects the production portfolio at the commercial market level. Reducing the total balancing reserve will increase the available generation capacity for commercial trading, which can influence better market interaction and efficiency. As a result, an analysis on the impact of variant levels of capacity on the commercial energy market operation is performed.

The electricity market model for each system in the region is created using GTMax software while taking into account the main assumptions and input data explained in Section 3.1.1. The specific details concerning the modeling are given in the Appendix.

As previously described, two electricity market simulations were performed based on the following principles of the day-ahead market:

- Simulation I – electricity market optimization for each system of interest, with individual dimensioning of balancing reserve
- Simulation II – electricity market optimization for simultaneous implementation of both cross-border balancing reserve cooperation models: common dimensioning and reserve sharing[23]
- Comparison between two simulations is performed in order to quantify market benefits for each system in terms of change in revenues and costs of system operation (production cost, export/import revenues and costs)

Though the simulation cases encompass the future status of the regional power systems without precisely predicted balancing schemes, there were two general assumptions concerning the structure of the reserve:

- For small systems (Armenia and Georgia) – 100% of the reserve is kept in the HPPs; and
- For large systems (Bulgaria, Romania, Turkey and Ukraine) – 1/3 is kept in the TPPs and 2/3 in the HPPs.

The only exception is Moldova, where the reserve is kept in the TPPs due to limited capacity in hydro power plants.

[23] To avoid unfeasibility of savings within the power system simulations, the maximal release of reserve capacities is applied through implementation of both cross-border balancing cooperation models.

In such a way, the obtained results are considered conservative when taking into account that the limited participation of the TPPs also limits total savings.

The following analyses was carried out separately for each sub-region, without full interactions with other sub-regions inside the BSTP. However, outside regions, like ENTSO-E, IPS/UPS or Central Asia, were taken into account on the level of the spot market and the assumed wholesale prices (as described in the Appendix).

In the following tables, the balancing reserve capacities for Simulation I are the total balancing reserves that must be provided in each system in case of an individual provision of balancing reserve. The capacities presented for Simulation II are necessary as reserve in each system, after the implementation of common dimensioning and reserve sharing models.

Sub-region A1 – Simulation Results

The balancing reserves for the system of interest are described in the following simulations:

		Simulation I	Simulation II	Δ [MW]
AM	**Balancing reserve [MW]**	**210**	**89**	**121**
	Technology providing balancing reserve	HPP (210 MW)	HPP (89 MW)	HPP (121 MW)
GE	**Balancing reserve [MW]**	**320**	**135**	**185**
	Technology providing balancing reserve	HPP (320 MW)	HPP (135 MW)	HPP (185 MW)

Table 5.3. Balancing Reserve Amounts Considered in the Study (AM & GE)

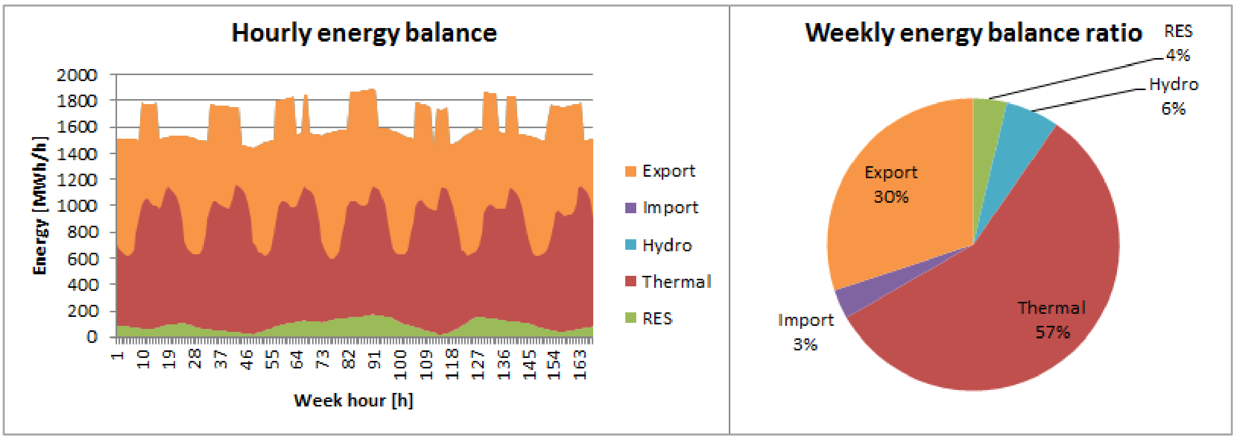

Figure 5.4 – Simulation I for Armenia – Without Common Dimensioning and Reserve Sharing

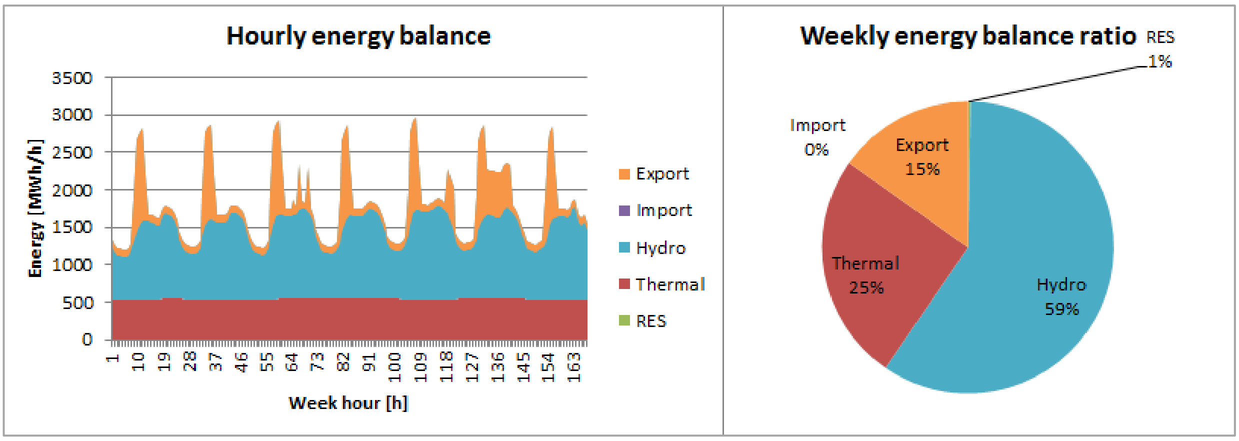

Figure 5.5 – Simulation I for Georgia – Without Common Dimensioning and Reserve Sharing

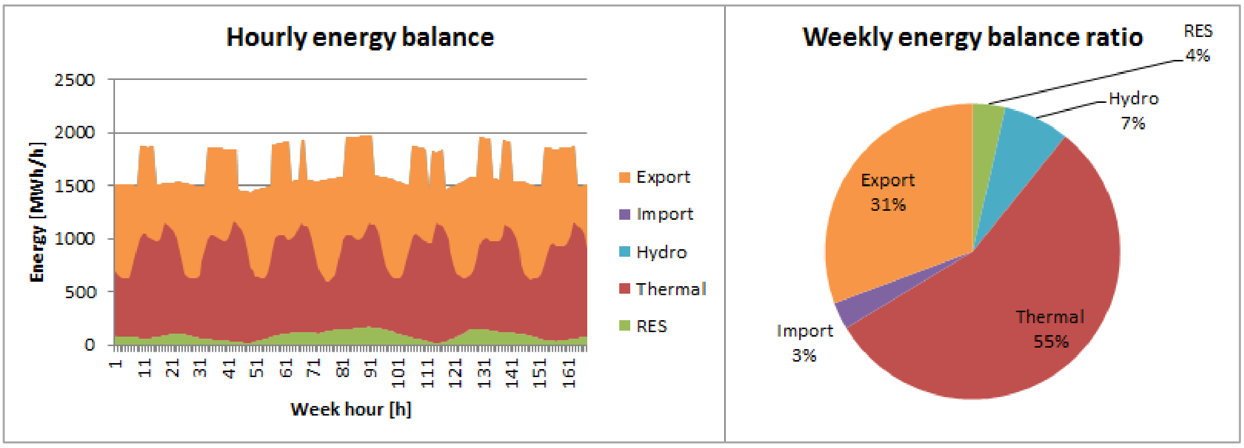

Figure 5.6 – Simulation II for Armenia – With Common Dimensioning and Reserve Sharing

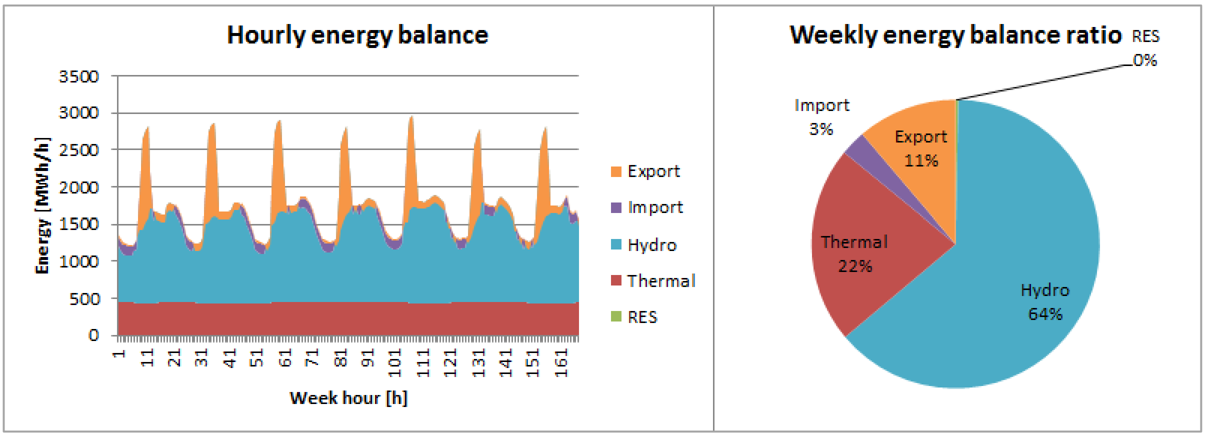

Figure 5.7 – Simulation II for Georgia – With Common Dimensioning and Reserve Sharing

The weekly hydro production in both areas (AM and GE) is the same in both simulations, with respect to available hydro energy for the observed week (defined by water inflows, and target levels of water in reservoirs at the start of the week and the end of the week).

As a result of higher available capacity in hydro power plants, efficient usage of water, superior hydrothermal coordination and units, dispatch is possible in the second optimization.

A total of 0.4 GWh Armenian and 1.2 GWh Georgian of weekly hydro production is shifted from off peak hours (00h-08h&20h-24h) to peak hours (08h-20h).

Energy production in the Georgian thermal power plants decreased due to superior hydrothermal coordination (an additional 185 MW in hydro power plants).

On the other side of the weekly energy export, is an increase in the Armenia export. This is a result of Armenia importing more in off-peak hours and saving water to export more in peak hours, which is enabled by an increase of 121 MW of available capacity in hydro power plants. Though Armenia and Georgia mutually exchange some energy, the majority of their power exchange is with their respective neighbors.

The total saving potential from the market operations for both areas is seen in two forms: increase of revenues from a better "shape" of import/export and the possibility to utilize their capacities more efficiently.

For Armenia, this benefit for the observed week is at the level of 11 thousand USD, while in case of Georgia this benefit is around 47 thousand USD.

Sub-region A2 – Simulation Results

The balancing reserves for the system of interest is described the following simulations:

		Simulation I	Simulation II	Δ [MW]
GE	**Balancing reserve [MW]**	**320**	**170**	**150**
	Technology providing balancing reserve	HPP (320 MW)	HPP (170 MW)	HPP (150 MW)
TR	**Balancing reserve [MW]**	**1000**	**530**	**470**
	Technology providing balancing reserve	TPP (333 MW)	TPP (177 MW)	TPP (156 MW)
		HPP (667MW)	HPP (353 MW)	HPP (314 MW)

Table 5.4. Balancing reserve amounts considered in the study (GE & TR)

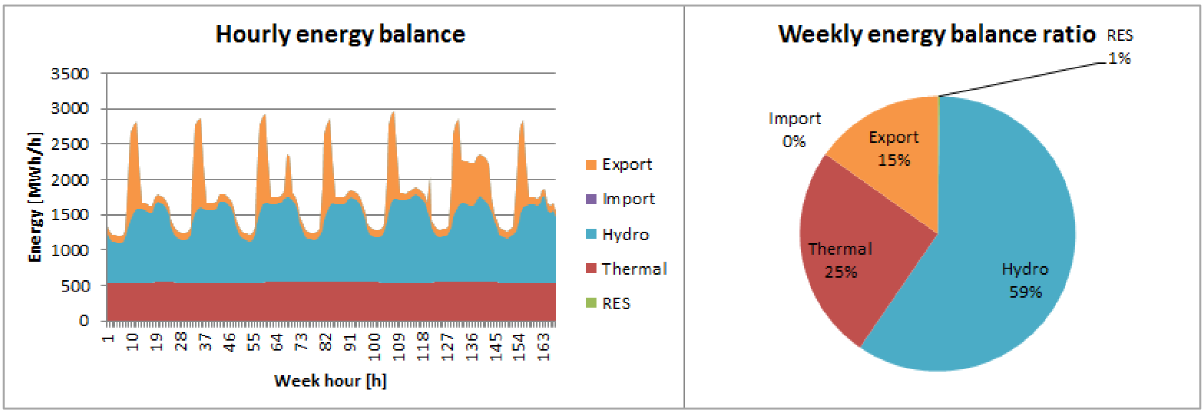

Figure 5.8 – Simulation I for Georgia – Without Common Dimensioning and Reserve Sharing

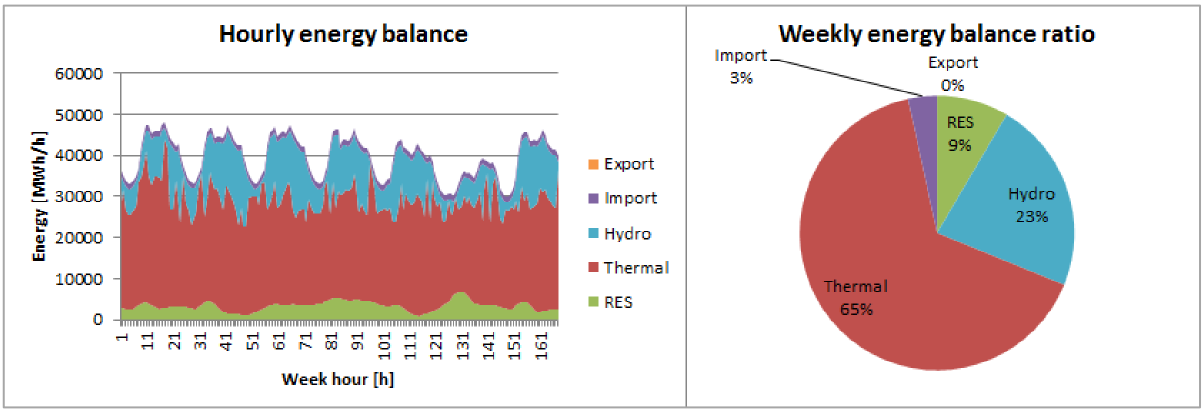

Figure 5.9 – Simulation I for Turkey – Without Common Dimensioning and Reserve Sharing

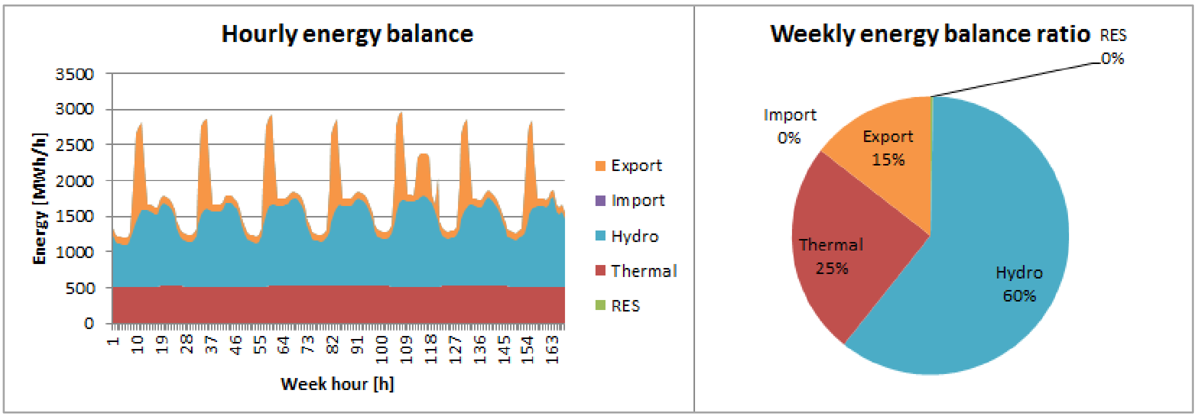

Figure 5.10 – Simulation II for Georgia – With Common Dimensioning and Reserve Sharing

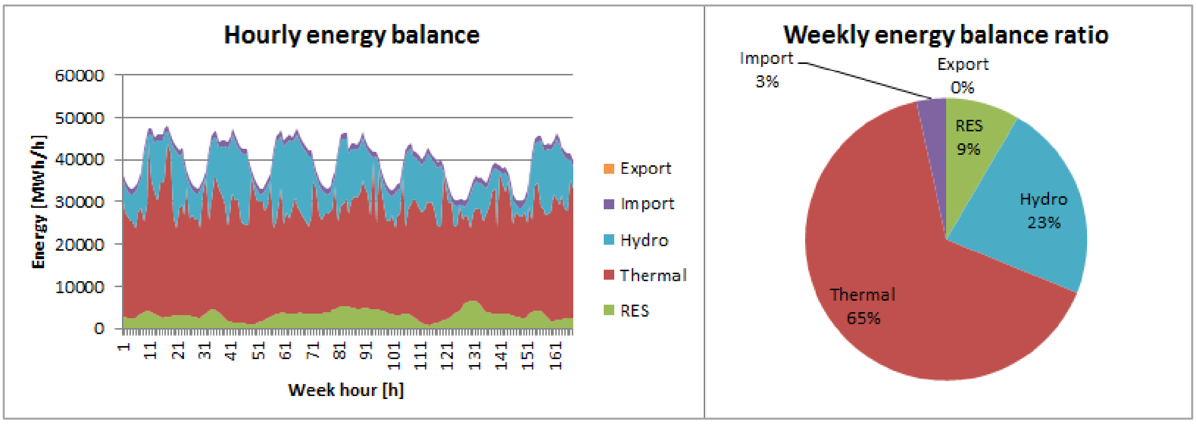

Figure 5.11 – Simulation II for Turkey – With Common Dimensioning and Reserve Sharing

As described in the previous case, the weekly hydro production in both areas (Georgia and Turkey) is the same in both simulations. Because of the higher available capacity in hydro power plants, more efficient usage of water, and better hydrothermal coordination and units, the dispatch is possible in the second optimization.

The total of weekly hydro production of 34 GWh in Turkey and approximately 0.6 GWh in Georgia is shifted from off peak hours (00h-08h&20h-24h) to peak hours (08h-20h).

The energy production in the Georgian thermal power plants is slightly decreased due to better hydrothermal coordination (additional 150 MW in hydro power plants).

Similar to the previous case, the Turkish energy import is decreased on the weekly level due to saved water for peak hours which is enabled by an increase of 470 MW of available capacity.

The total saving potential from market operations for both areas is seen in two forms: increase of revenues from a better "shape" of import/export and the possibility to utilize their capacities more efficiently.

For Turkey, this benefit for the observed week is at the level of approximately 632 thousand USD, when comparing the case with and without common dimensioning and reserve sharing. In the case of Georgia, this is at the level of 22 thousand USD.

Sub-region B – Simulation Results

The balancing reserves for the system of interest is described in the following simulations:

		Simulation I	Simulation II	Δ [MW]
BG	**Balancing reserve [MW]**	**1040**	**248**	**792**
	Technology providing balancing reserve	TPP (347 MW)	TPP (83 MW)	TPP (264 MW)
		HPP (693 MW)	HPP (165 MW)	HPP (528 MW)
RO	**Balancing reserve [MW]**	**1000**	**240**	**760**
	Technology providing balancing reserve	TPP (333 MW)	TPP (80 MW)	TPP (253 MW)
		HPP (667MW)	HPP (160 MW)	HPP (507 MW)
TR	**Balancing reserve [MW]**	**1000**	**240**	**760**
	Technology providing balancing reserve	TPP (333 MW)	TPP (80 MW)	TPP (253 MW)
		HPP (667MW)	HPP (160 MW)	HPP (507 MW)

Table 5.5. Balancing Reserve Amounts Considered in the Study (BG & RO & TR)

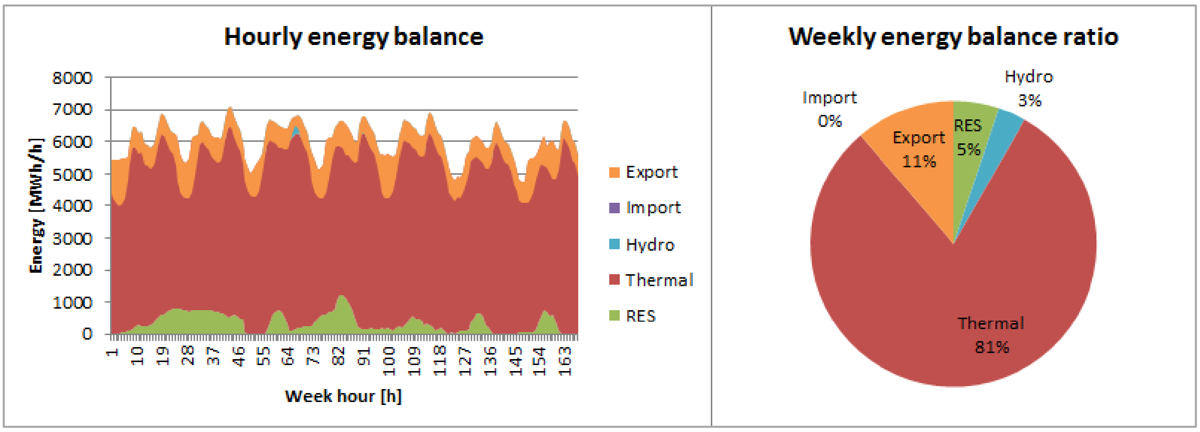

Figure 5.12 – Simulation I for Bulgaria – Without Common Dimensioning and Reserve Sharing

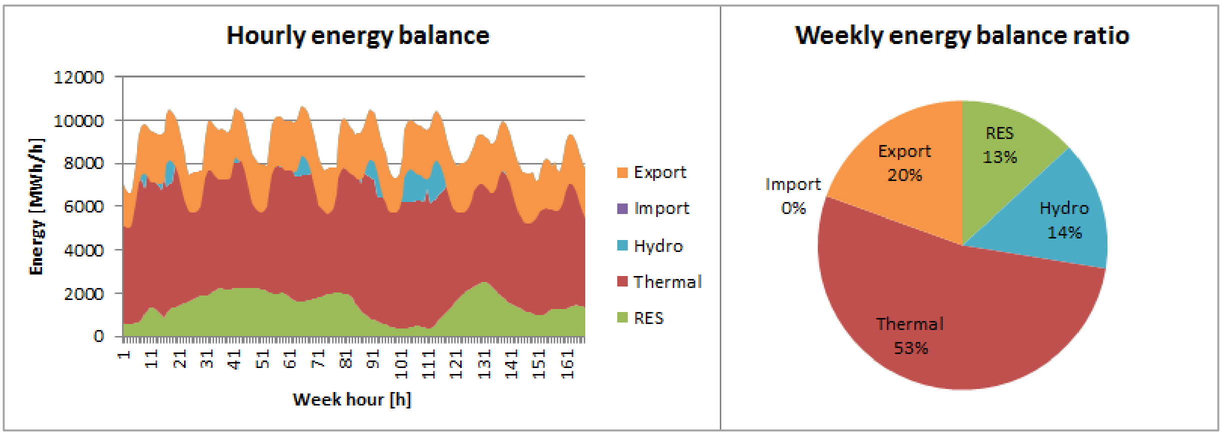

Figure 5.13 – Simulation I for Romania – Without Common Dimensioning and Reserve Sharing

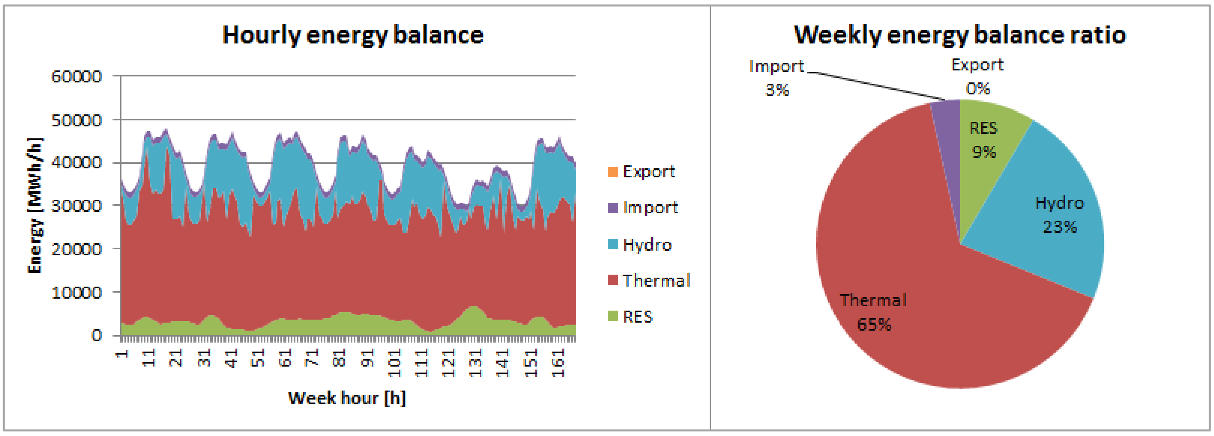

Figure 5.14 – Simulation I for Turkey – Without Common Dimensioning and Reserve Sharing

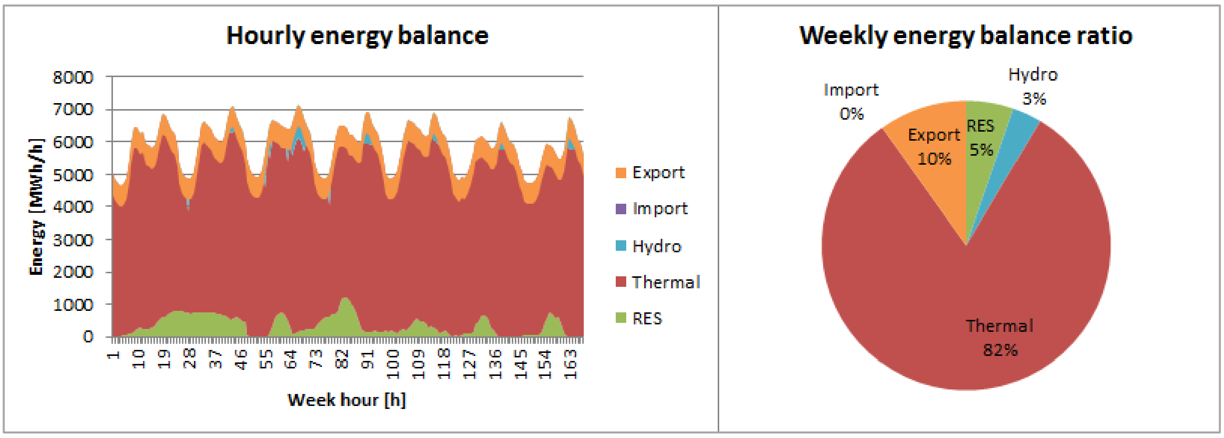

Figure 5.15 – Simulation II for Bulgaria – With Common Dimensioning and Reserve Sharing

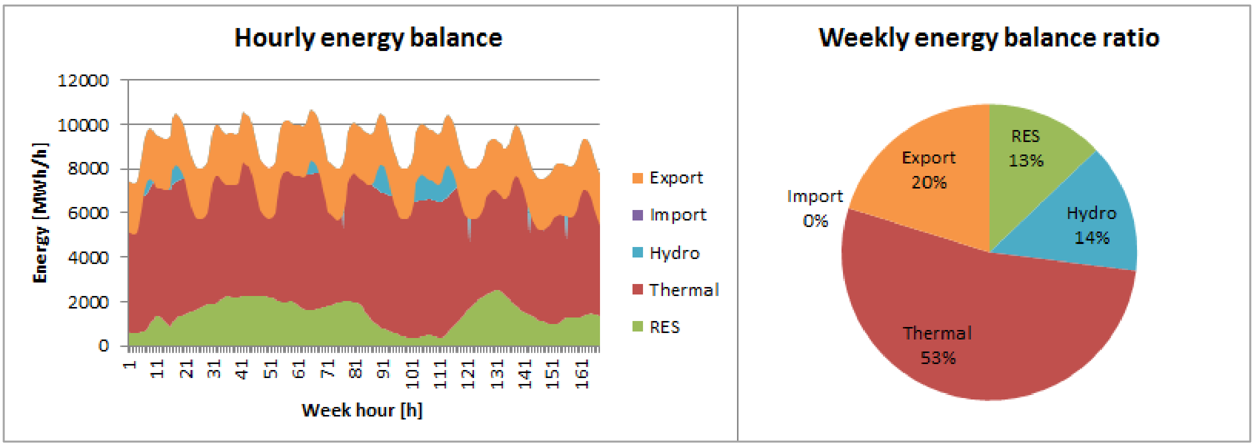

Figure 5.16 – Simulation II for Romania – With Common Dimensioning and Reserve Sharing

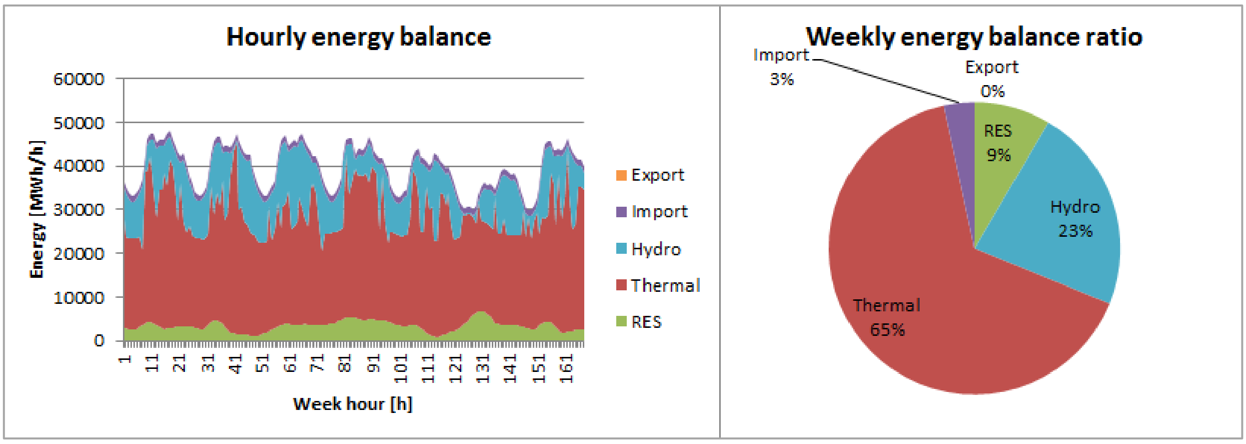

Figure 5.17 – Simulation II for Turkey – With Common Dimensioning and Reserve Sharing

The energy production in the thermal power plants increased in Romania by 21 GWh, due to the higher available capacity. At the same time, the thermal power plants decreased generation in Bulgaria and Turkey (taking this energy surplus) due to the more attractive importing costs in comparison with domestic capacities when utilizing the same technology.

The weekly hydro production from run-of-river and reservoir HPPs is the same in both simulations, with respect to available hydro energy for the observed week (defined by water inflows, and target levels of water in reservoirs at start of the week and end of the week).

Because of the higher available capacity in hydro power plants, more efficient usage of water, better hydrothermal coordination, units dispatch is possible in the second optimization. However, their effects were very modest in terms of the specific structure of the balancing reserve and its corresponding available technology. In this simulation case, a significant level of reserve is kept in thermal units for all TSOs and production cost optimization is based on a generation equilibrium among the balancing participating units in the sub-region.

The total saving potential from market operation is seen in two forms: increase of revenues from a better "shape" of import/export and the possibility of increased efficient utilization of capacities. This benefit for the observed week is at the level of about 271 thousand USD for Bulgaria, 220 thousand UDS for Romania and 1348 thousand USD for Turkey.

Sub-region C – Simulation Results

The balancing reserves for the system of interest is described the following simulations:

		Simulation I	Simulation II	Δ [MW]
MD	**Balancing reserve [MW]**	**210**	**121**	**89**
	Technology providing balancing reserve	TPP (210 MW)	TPP (121 MW)	TPP (89 MW)
UA	**Balancing reserve [MW]**	**1000**	**579**	**421**
	Technology providing balancing reserve	TPP (333 MW)	TPP (193 MW)	TPP (140 MW)
		HPP (667MW)	HPP (386 MW)	HPP (281 MW)

Table 5.6. Balancing Reserve Amounts Considered in the Study (MD & UA)

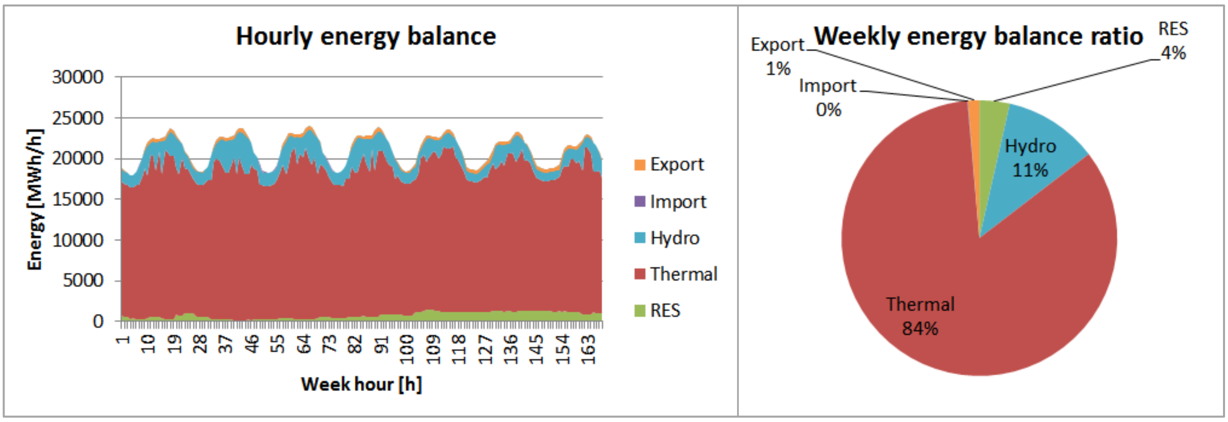

Figure 5.18 – Simulation I for Ukraine – Without Common Dimensioning and Reserve Sharing

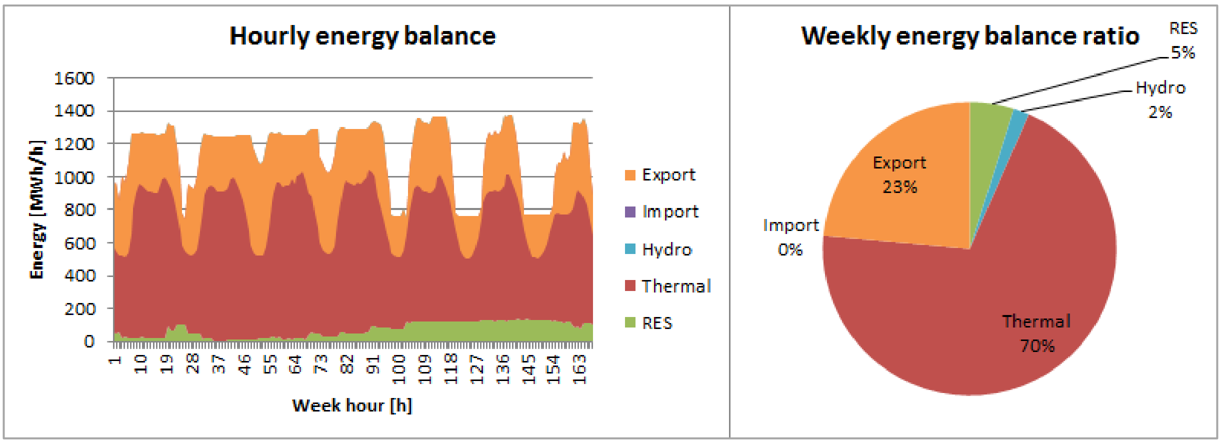

Figure 5.19 – Simulation I for Moldova – Without Common Dimensioning and Reserve Sharing

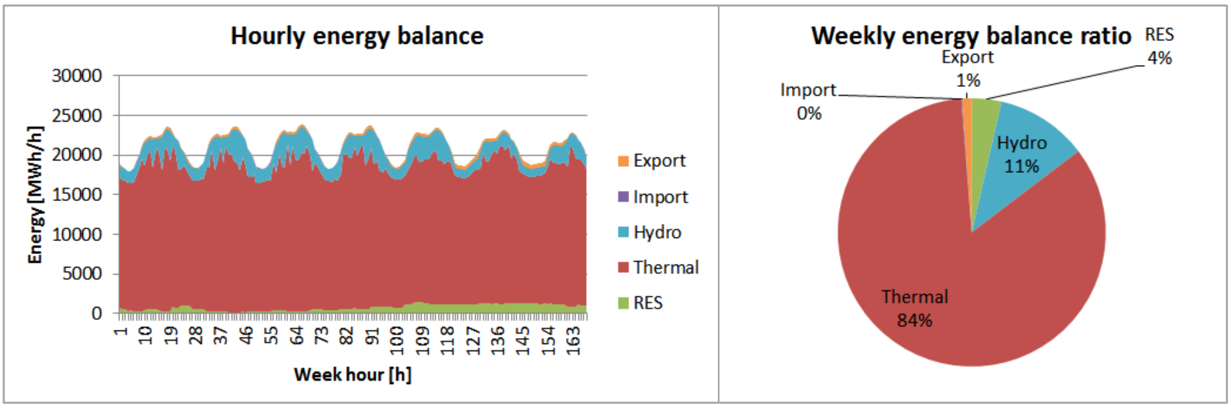

Figure 5.20 – Simulation II for Ukraine – With Common Dimensioning and Reserve Sharing

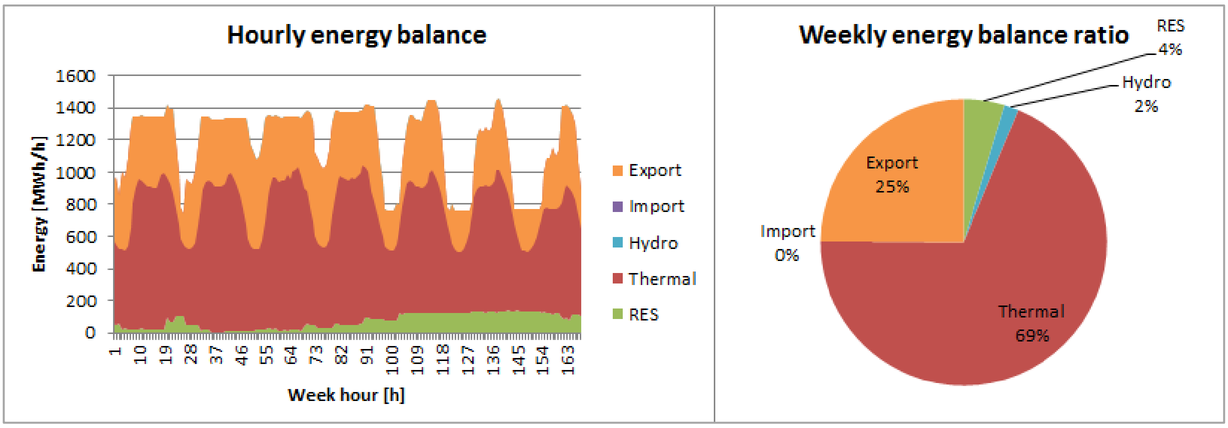

Figure 5.21 – Simulation II for Moldova – With Common Dimensioning and Reserve Sharing

Energy production in thermal power plants in Moldova increased by 6.7 GWh or 4% on weekly level, due to a higher available capacity (obtained as a result of common dimensioning within the UA-MD LFC block, and reserve sharing of UA-MD and foreign LFC blocks). At the same time, the thermal power plants' production in Ukraine slightly decreased due to the available cheaper capacity in Moldova.

The weekly hydro production in Ukraine is the same in both simulations, with respect to available hydro energy for the observed week (defined by water inflows, and target levels of water in reservoirs at the start of the week and the end of the week). However, as there is a higher available capacity in hydro power plants, more efficient usage of water and hydro units dispatch is possible in the second optimization. Due to this, the total 460 MWh of weekly hydro production is shifted from off peak hours (00h-08h&20h-24h) to peak hours (08h-20h), enabling less import of expensive energy in peak hours on account of more import of cheaper energy in off peak hours.

The total saving potential resulting from market operations for Ukraine and Moldova is seen in two forms: increase of revenues from better "shape" of import/export and the possibility to utilize their own capacities more efficiently. For Ukraine, this benefit for the observed week is at the level of about 82 thousand USD when comparing cases with and without common dimensioning and reserve sharing. In the case of Moldova, this is at a level of approximately 55 thousand USD.

The estimated potential weekly savings for all cases are in a range of several dozens of thousand USD to more than a million (in the case of Turkey).

Sub-region	Individual dimensioning (Simulation I) [MW]			Joint dimensioning and reserve sharing (Simulation II) [MW]			Savings (Thousand USD)		
	TSO1	TSO2	TSO3	TSO1	TSO2	TSO3	TSO1	TSO2	TSO3
A1: Armenia (TSO1) – Georgia (TSO2)	210	320	-	89	135	-	11	47	-
A2: Georgia (TSO1) –Turkey (TSO2)	320	1000	-	170	530	-	22	620	-
B: Bulgaria (TSO1) –Romania (TSO2) –Turkey (TSO3)	1040	1000	1000	248	240	240	271	220	1348
C: Moldova (TSO1) – Ukraine (TSO2)	210	1000	-	121	579	-	55	82	-

The performed analysis reflects the potential savings at the level of a characteristic week in the most critical season (winter) as the most exemplary period for a clear demonstration of benefits of common dimensioning and reserve sharing. For other seasons, the expected potential savings could be estimated at a level of 50% to 70% when compared with the winter season.

Figure 5.22 Individual Dimensioning, Joint Dimensioning and Resulting Savings (Thousand USD)

5.2 Assessment of Common Usage of Balancing Energy

The impact assessment and potential savings from the implementation of exchange of balancing energy, are examined on illustrative examples of real power systems. The following balancing mechanisms for cross border exchange of balancing energy are analyzed:

- Imbalance netting
- Exchange of aFRR balancing energy
- Exchange of mFRR/RR balancing energy.

5.2.1 Calculation of Direct Benefits of Imbalance Netting

A demonstration of the possible potential savings from introducing the imbalance netting mechanism is provided in the illustrative examples below.

The analysis is performed on 43,200 samples for each power system (one characteristic day) and the Area Control Error (ACE) is taken on a 2 seconds resolution. The missing ACE data has been estimated as described in Section 4.1.1.

As previously mentioned (3.2.2), three cases are created, simulated and compared in terms of accounting aFRR activated energy:

- CASE 1: aFRR activated energy is quantified as a single value within the settlement period of 1 hour (cumulative value of activated energy in both positive and negative directions; "netting in time" on the level of 1 hour)
- CASE 2: aFRR activated energy is quantified as a single value within the settlement period of 15 minutes (cumulative value of activated energy in both positive and negative directions; "netting in time" on the level of 15 minutes)
- CASE 3: aFRR activated energy is quantified separately for upward and downward regulation within the settlement period (no "netting in time").

The opportunity prices used for assessing benefits of implementation of imbalance netting were discussed within 3.2.2 and they are based on data provided in questionnaires and additional estimations:

Country	Upward regulation price ($/MWh)	Downward regulation price ($/MWh)
Armenia	60.8	3.4
Bulgaria	65.0	3.6
Georgia	98.3	5.5
Moldova	107.5	6.0
Romania	69.0	0.6
Turkey	93.1	5.2
Ukraine	64.8	3.6

Table 5.7. Upward and Downward Regulation Prices in Market-based Approach

As previously described, the sensitivity analysis was performed for the countries with undeveloped balancing markets (Armenia, Georgia, Moldova and Ukraine) based on the "cost based approach" and the following average balancing energy prices based on:

Country	Upward regulation price ($/MWh)	Downward regulation price ($/MWh)
Armenia	41.4	6.9
Georgia	46.9	7.8
Moldova	43.2	7.2
Ukraine	42.0	7.0

Table 5.8. Upward and Downward Regulation Costs in Cost-based Approach

Sub-region A1 – Simulation Results

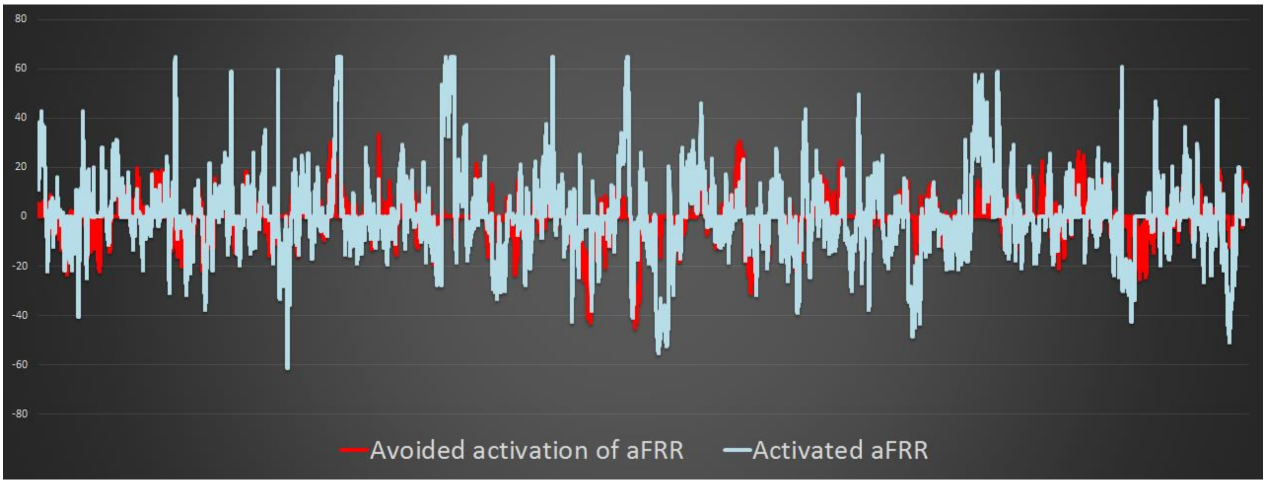

Figure 5.23 – Activated aFRR with Imbalance Netting for GE

GE		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	7016	12562	17596
	Downward regulation cost [$]	-343	-654	-935
	Total cost [$]	6672	11908	16660
WITH IMBALANCE NETTING	Upward regulation cost [$]	6416	10003	13373
	Downward regulation cost [$]	-268	-469	-657
	Total cost [$]	6148	9534	12716
POTENTIAL SAVINGS [$]		**524**	**2374**	**3945**
POTENTIAL SAVINGS [%]		**7.8%**	**19.9%**	**23.7%**

Table 5.9 – Observed Daily Benefits of Imbalance Netting Implementation for GE

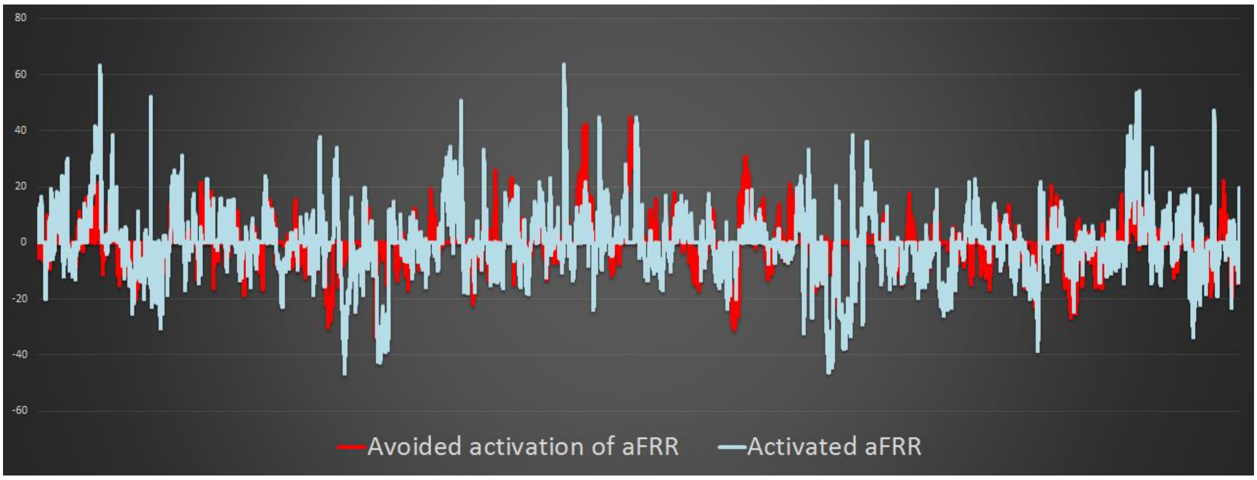

Figure 5.24 – Activated aFRR with Imbalance Netting for AM

AM		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	4008	6083	8501
	Downward regulation cost [$]	-197	-313	-448
	Total cost [$]	3811	5771	8053
WITH IMBALANCE NETTING	Upward regulation cost [$]	2841	4168	5427
	Downward regulation cost [$]	-150	-232	-302
	Total cost [$]	2691	3937	5125
POTENTIAL SAVINGS [$]		**1120**	**1834**	**2928**
POTENTIAL SAVINGS [%]		**29.4%**	**31.8%**	**36.4%**

Table 5.10 – Observed Daily Benefits of Imbalance Netting Implementation for AM

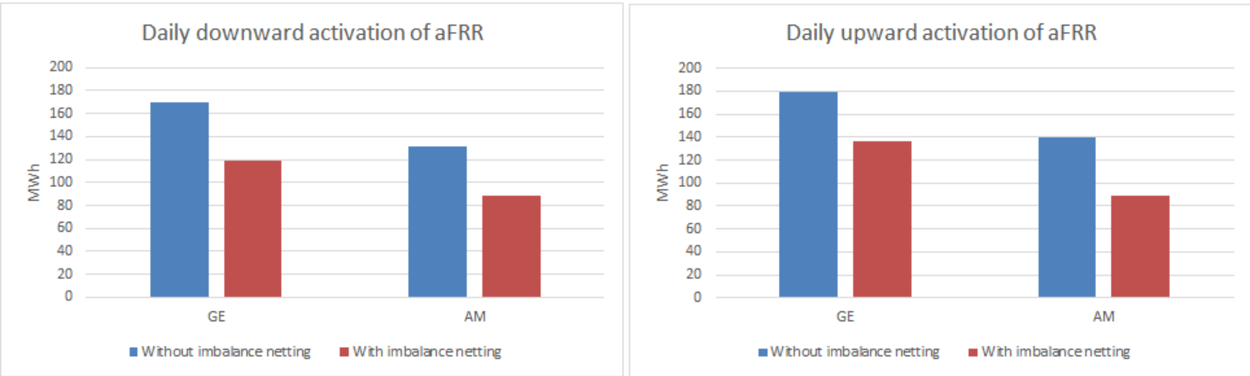

Figure 5.25 – Upward and Downward Activation of aFRR

GE&AM		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	11023	18645	26097
	Downward regulation cost [$]	-540	-967	-1383
	Total cost [$]	10483	17679	24713
WITH IMBALANCE NETTING	Upward regulation cost [$]	9258	14171	18800
	Downward regulation cost [$]	-418	-700	-959
	Total cost [$]	8840	13471	17840
POTENTIAL SAVINGS [$]		**1643**	**4208**	**6873**
POTENTIAL SAVINGS [%]		**15.7%**	**23.8%**	**27.8%**

Table 5.11 – Observed Daily Benefits of Imbalance Netting Implementation

By analyzing the results, the Study concludes the following:

- Activation of upward aFRR energy is decreased by 30%.
- Activation of downward aFRR energy is decreased by 31%.
- Total activation of aFRR energy is decreased by 30%, and therefore an unnecessary level of generators engagement for frequency restoration is avoided.
- For each of the six scenarios, the saving potential (monetary) observed for sub-region A1 is positive, and varies between 1.6 and 6.9 thousand EUR/day, i.e. between 15.7% and 28%.

- In cases where both positive and negative directions of activated aFRR are quantified within the settlement period, without cumulating (no "netting in time"), the observed benefits are the highest and always positive for each TSO participating in the process.
- In order to quantify the yearly saving potential from introducing imbalance netting in sub-region A1, additional detail analysis is needed after the establishment of all national balancing markets with clear price signals for aFRR activated energy, and available data regarding power system imbalances for longer period of time (1 to 2 years).
- Nevertheless, the analysis performed within this study provides a clear positive signal from the implementation of imbalance netting in sub-region A1, with potential annual savings that can be roughly estimated at a level of 0.6 to 2.5 million of USD depending on the applied aFRR energy measuring and pricing rules.

<u>"Cost Based" Sensitivity Analysis</u>

Taking into account BSRI average balancing prices for Armenia, Georgia, Moldova and Ukraine given in Table 3.6, the following direct benefits of imbalance netting for all three cases for Georgia and Armenia (sub-region A1) were obtained (Table 5.12).

GE		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	3512	5990	8390
	Downward regulation cost [$]	-488	-928	-1328
	Total cost [$]	3025	5061	7062
WITH IMBALANCE NETTING	Upward regulation cost [$]	3060	4770	6376
	Downward regulation cost [$]	-381	-666	-933
	Total cost [$]	2679	4104	5443
POTENTIAL SAVINGS [$]		346	957	1619
POTENTIAL SAVINGS [%]		11.4%	18.9%	22.9%

AM		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	2727	4140	5785
	Downward regulation cost [$]	-798	-1269	-1818
	Total cost [$]	1929	2870	3967
WITH IMBALANCE NETTING	Upward regulation cost [$]	1933	2837	3693
	Downward regulation cost [$]	-608	-940	-1225
	Total cost [$]	1325	1897	2468
POTENTIAL SAVINGS [$]		603	974	1499
POTENTIAL SAVINGS [%]		31.3%	33.9%	37.8%

GE&AM		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	6240	10129	14175
	Downward regulation cost [$]	-1286	-2198	-3146
	Total cost [$]	4953	7932	11029
WITH IMBALANCE NETTING	Upward regulation cost [$]	4993	7606	10069
	Downward regulation cost [$]	-989	-1605	-2159
	Total cost [$]	4004	6001	7911
POTENTIAL SAVINGS [$]		949	1931	3118
POTENTIAL SAVINGS [%]		19.2%	24.3%	28.3%

Table 5.12 – Summary of Observed Daily Benefits of Imbalance Netting Implementation (cost based approach GE & AM))

The total potential savings for both TSOs are about 60% lower in comparison with the so called "market based" approach, as expected when considering the range of upward and downward regulation prices:

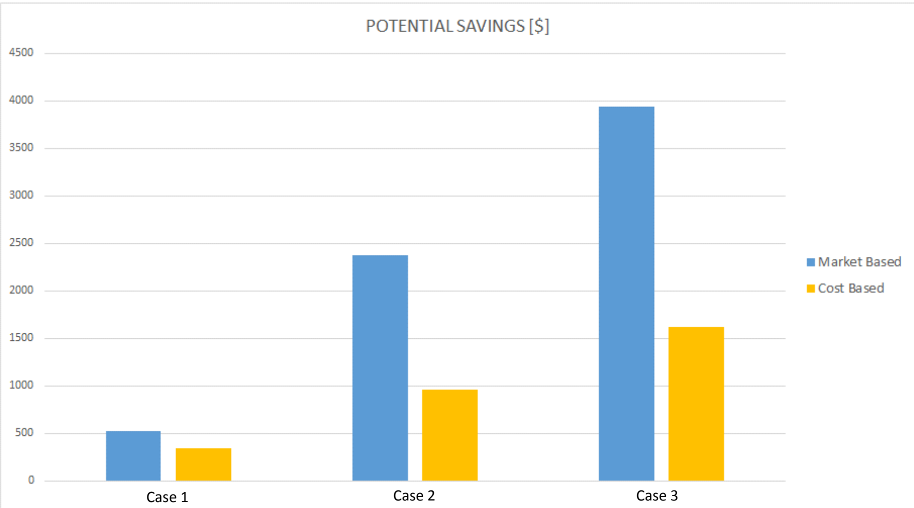

Table 5.13 – Market and Cost Based Total Potential Savings Per Case

However, it is important to note that relative savings (in %) are similar in both approaches.

Sub-region A2 – simulation results

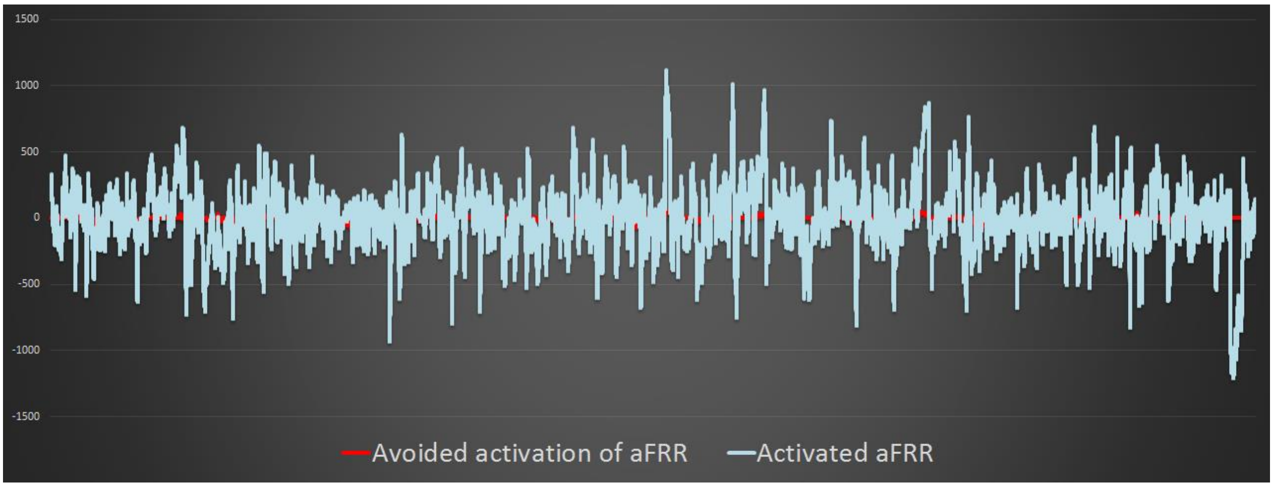

Figure 5.26 – Activated aFRR with Imbalance Netting for TR

TR		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	67640	105514	212732
	Downward regulation cost [$]	-2834	-4950	-10938
	Total cost [$]	64805	100564	201794
WITH IMBALANCE NETTING	Upward regulation cost [$]	67071	103860	205319
	Downward regulation cost [$]	-2806	-4861	-10527
	Total cost [$]	64265	99000	194792
POTENTIAL SAVINGS [$]		540	1565	7003
POTENTIAL SAVINGS [%]		0.8%	1.6%	3.5%

Table 5.14 – Observed Daily Benefits of Imbalance Netting Implementation for TR

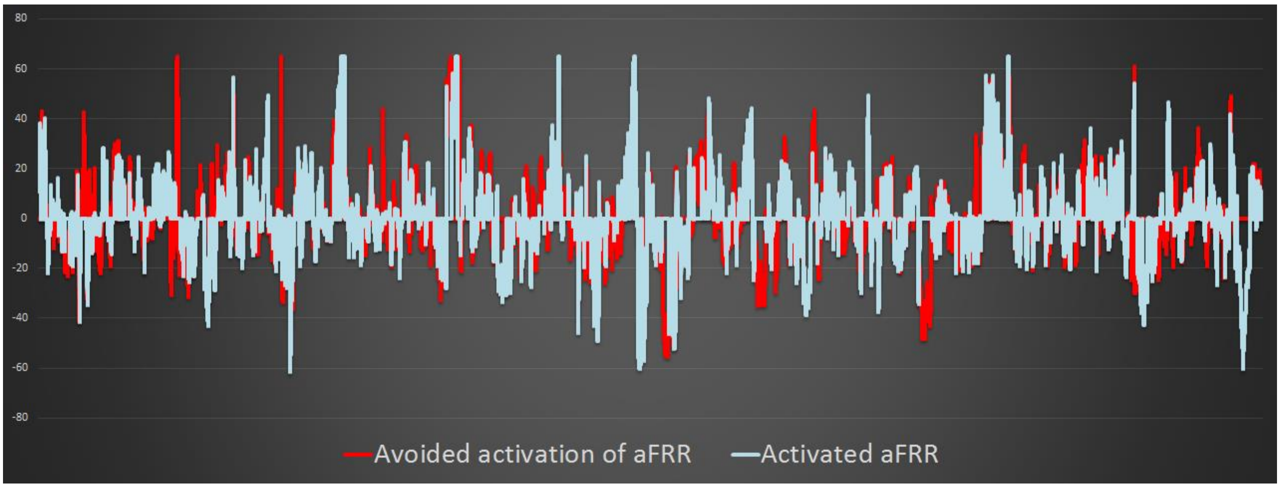

Figure 5.27 – Activated aFRR with Imbalance Netting for GE

GE		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	7016	12562	17596
	Downward regulation cost [$]	-343	-654	-935
	Total cost [$]	6672	11908	16660
WITH IMBALANCE NETTING	Upward regulation cost [$]	4489	7965	9828
	Downward regulation cost [$]	-199	-393	-497
	Total cost [$]	4291	7572	9331
POTENTIAL SAVINGS [$]		2381	4336	7330
POTENTIAL SAVINGS [%]		35.7%	36.4%	44.0%

Table 5.15 – Observed Daily Benefits of Imbalance Netting Implementation for GE

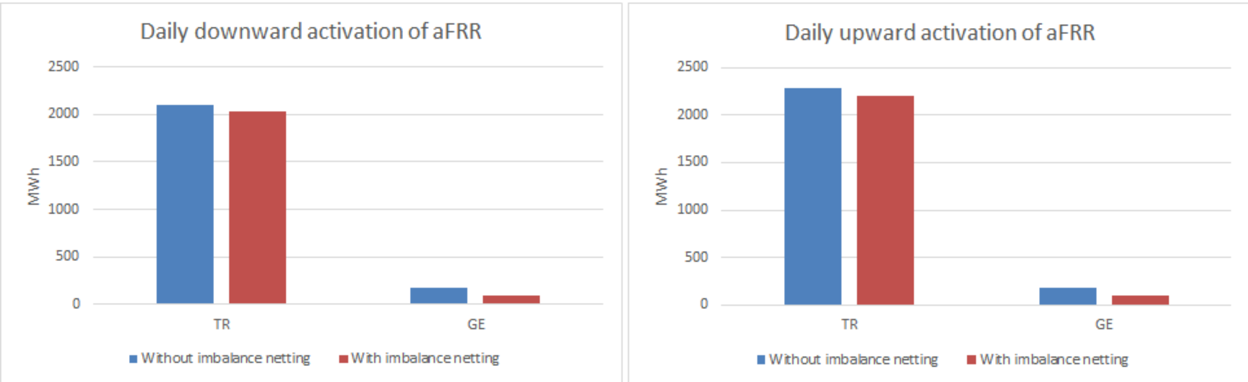

Figure 5.28 – Upward and Downward Activation of aFRR

TR&GE		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	74655	118076	230328
	Downward regulation cost [$]	-3178	-5603	-11874
	Total cost [$]	71478	112473	218455
WITH IMBALANCE NETTING	Upward regulation cost [$]	71561	111825	215147
	Downward regulation cost [$]	-3004	-5254	-11025
	Total cost [$]	68556	106572	204122
POTENTIAL SAVINGS [$]		2921	5901	14333
POTENTIAL SAVINGS [%]		4.1%	5.2%	6.6%

Table 5.16 – Observed Daily Benefits of Imbalance Netting Implementation

By analyzing the results, the Study concludes the following:

- Activation of upward aFRR energy is decreased by 6.4%.
- Activation of downward aFRR energy is decreased by 6.9%.
- Total activation of aFRR energy is decreased by 6.7%, and therefore an unnecessary level of generators engagement for frequency restoration is avoided.
- For each of the six scenarios, the saving potential (monetary) observed for sub-region A2 is positive, and varies between 2.9 and 14 thousand EUR/day, i.e. between 4.1% and 6.6%.

- In cases where both positive and negative directions of activated aFRR are quantified within the settlement period, without cumulating (no "netting in time"), the observed benefits are the highest and always positive for each TSO participating in the process.
- In order to quantify the yearly saving potential resulting from imbalance netting in sub-region A2, an additional detailed analysis is needed after the establishment of all national balancing markets with clear price signals for aFRR activated energy, and available data regarding power system imbalances for a longer period of time (1 to 2 years).
- Nevertheless, the study analysis provides a clear positive signal resulting from the implementation of imbalance netting in sub-region A2, with potential annual savings that can be roughly estimated at a level of 1 to 5 million of USD depending on the applied aFRR energy measuring and pricing rules.

Sub-region B – Simulation Results

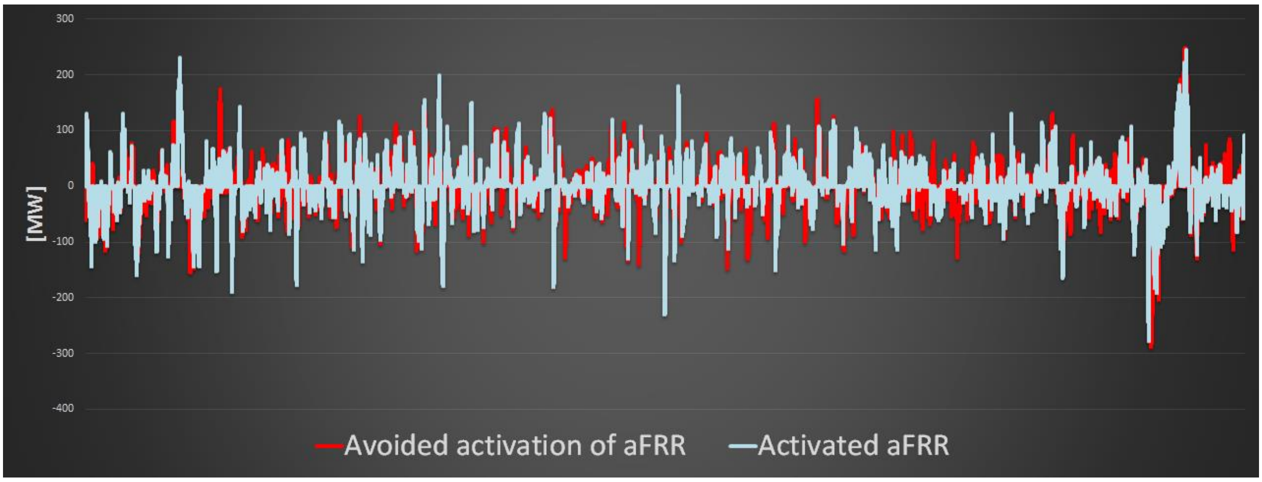

Figure 5.29 – Activated aFRR with Imbalance Netting for RO

RO		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	6861	18640	37581
	Downward regulation cost [$]	-34	-136	-301
	Total cost [$]	6827	18504	37280
WITH IMBALANCE NETTING	Upward regulation cost [$]	5065	11733	21024
	Downward regulation cost [$]	-13	-71	-152
	Total cost [$]	5052	11662	20872
POTENTIAL SAVINGS [$]		**1775**	**6842**	**16408**
POTENTIAL SAVINGS [%]		**26.0%**	**37.0%**	**44.0%**

Table 5.17 – Observed Daily Benefits of Imbalance Netting Implementation for RO

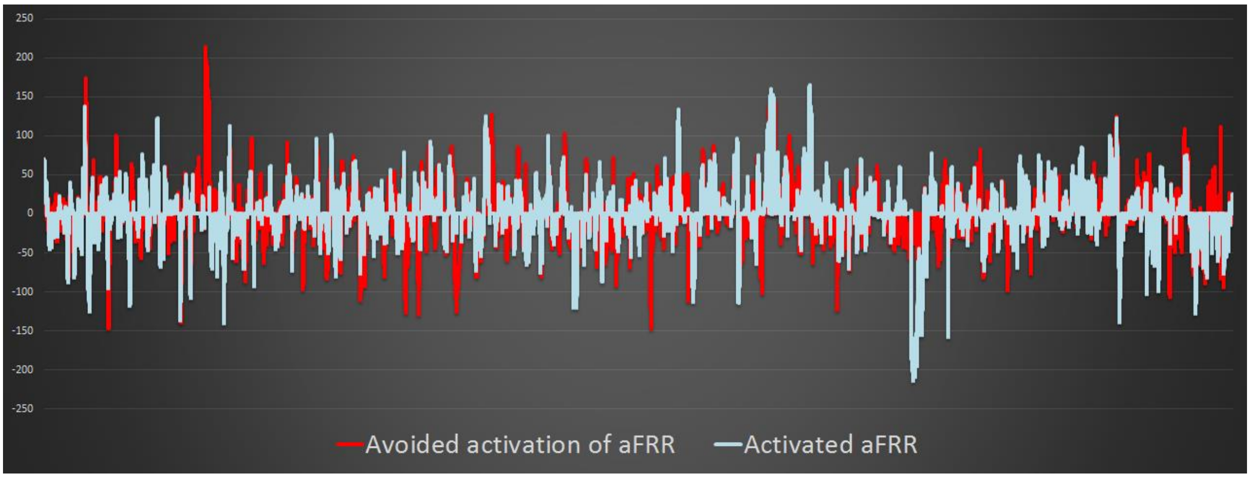

Figure 5.30 – Activated aFRR with Imbalance Netting for BG

BG		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	8458	13447	27112
	Downward regulation cost [$]	-349	-626	-1382
	Total cost [$]	8109	12822	25729
WITH IMBALANCE NETTING	Upward regulation cost [$]	5454	7605	13618
	Downward regulation cost [$]	-229	-348	-681
	Total cost [$]	5224	7257	12936
POTENTIAL SAVINGS [$]		**2884**	**5565**	**12793**
POTENTIAL SAVINGS [%]		**35.6%**	**43.4%**	**49.7%**

Table 5.18 – Observed Daily Benefits of Imbalance Netting Implementation for BG

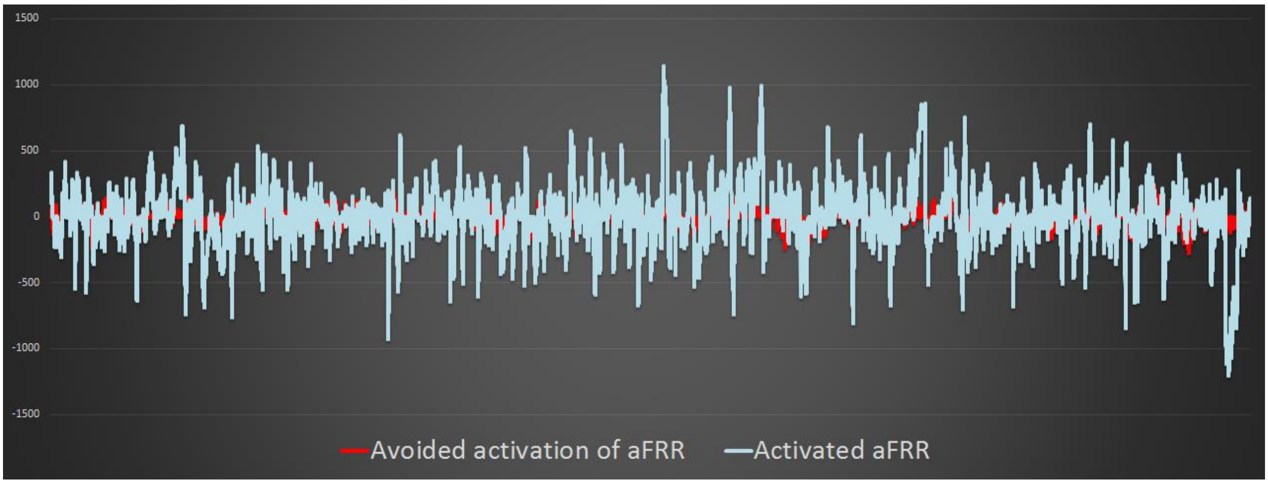

Figure 5.31 – Activated aFRR with Imbalance Netting for TR

TR		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	67640	105514	212732
	Downward regulation cost [$]	-2834	-4950	-10938
	Total cost [$]	64805	100564	201794
WITH IMBALANCE NETTING	Upward regulation cost [$]	63147	94440	180566
	Downward regulation cost [$]	-2561	-4309	-9119
	Total cost [$]	60586	90131	171447
POTENTIAL SAVINGS [$]		**4220**	**10434**	**30347**
POTENTIAL SAVINGS [%]		**6.5%**	**10.4%**	**15.0%**

Table 5.19 – Observed Daily Benefits of Imbalance Netting Implementation for TR

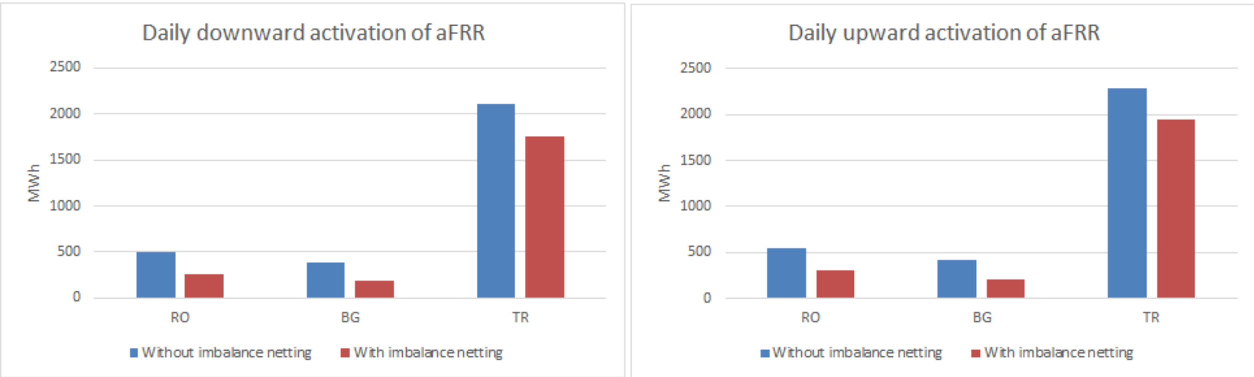

Figure 5.32 – Upward and Downward Activation of aFRR

RO&BG&TR		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	82958	137601	277425
	Downward regulation cost [$]	-3217	-5711	-12621
	Total cost [$]	86176	143313	290046
WITH IMBALANCE NETTING	Upward regulation cost [$]	73666	113777	215208
	Downward regulation cost [$]	-2803	-4728	-9953
	Total cost [$]	76469	118506	225161
POTENTIAL SAVINGS [$]		**9707**	**24807**	**64885**
POTENTIAL SAVINGS [%]		**11.3%**	**17.3%**	**22.4%**

Table 5.20 – Observed Daily Benefits of Imbalance Netting Implementation

By analyzing the results, the Study concludes the following:

- Activation of upward aFRR energy is decreased by 24.4%.
- Activation of downward aFRR energy is decreased by 26.5%.
- Total activation of aFRR energy is decreased by 25.4%, and therefore an unnecessary level of generator engagement for frequency restoration is avoided.
- For each of the six scenarios, the saving potential (monetary) observed for sub-region B is positive, and varies between 10 and 65 thousand USD/day, i.e. between 11% and 22%.

- In cases where both positive and negative directions of activated aFRR are quantified in the settlement period without cumulating (no "netting in time"), the observed benefits are the highest and always positive for each TSO participating in the process.
- In order to quantify the yearly savings potential resulting from imbalance netting in sub-region B, additional detailed analysis is needed after the establishment of all national balancing markets with clear price signals for aFRR activated energy and available data regarding power system imbalances for a longer period of time (1 to 2 years).
- Nevertheless, the analysis performed provides a clear positive signal from the implementation of imbalance netting in sub-region B, with potential annual savings that can be roughly estimated at a level of 3 to 23 million of Euros depending on the applied aFRR energy measuring and pricing rules.

Sub-region C – simulation results

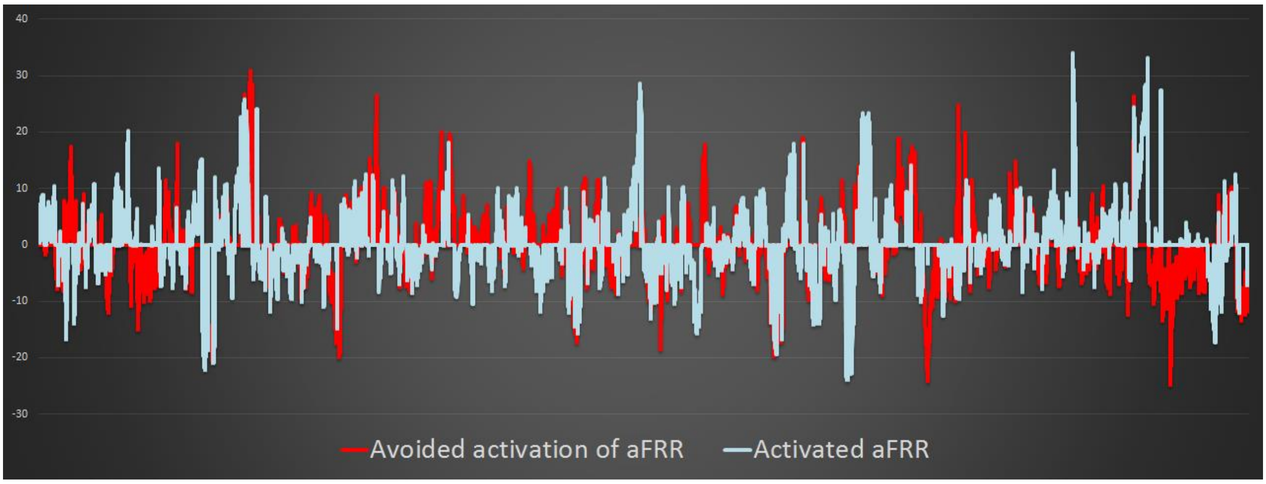

Figure 5.33 – Activated aFRR with Imbalance Netting for MD

MD		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	3087	5647	7873
	Downward regulation cost [$]	-143	-286	-410
	Total cost [$]	2945	5362	7463
WITH IMBALANCE NETTING	Upward regulation cost [$]	2134	3739	4428
	Downward regulation cost [$]	-57	-147	-185
	Total cost [$]	2077	3592	4243
POTENTIAL SAVINGS [$]		**868**	**1770**	**3220**
POTENTIAL SAVINGS [%]		**29.5%**	**33.0%**	**43.1%**

Table 5.21 – Observed Daily Benefits of Imbalance Netting Implementation for MD

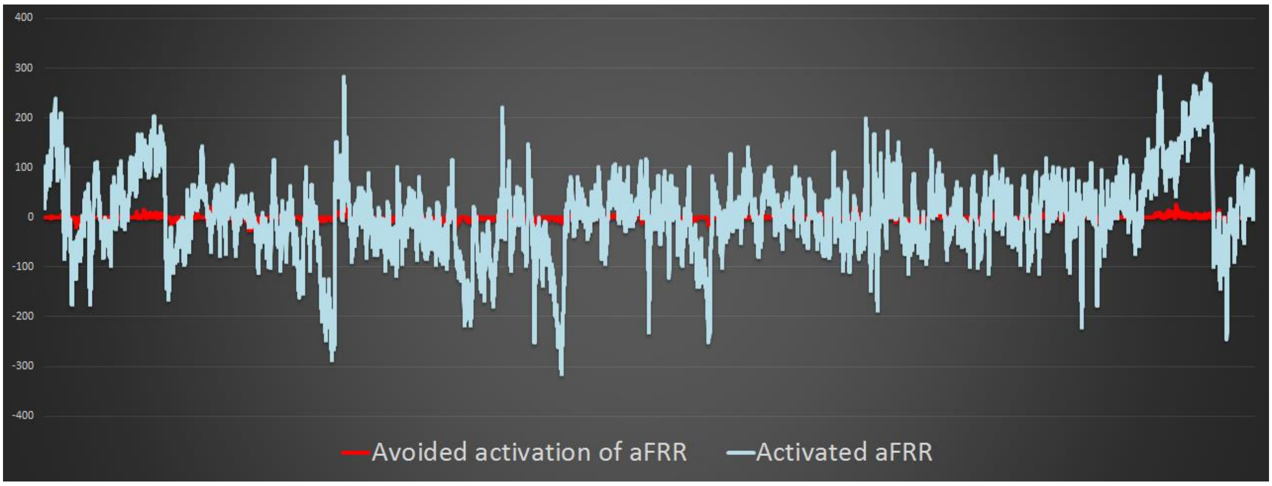

Figure 5.34 – Activated aFRR with Imbalance Netting for UA

UA		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	28284	39174	53393
	Downward regulation cost [$]	-1044	-1649	-2439
	Total cost [$]	27240	37525	50955
WITH IMBALANCE NETTING	Upward regulation cost [$]	27520	37507	50967
	Downward regulation cost [$]	-1021	-1576	-2323
	Total cost [$]	26499	35931	48643
POTENTIAL SAVINGS [$]		**741**	**1594**	**2311**
POTENTIAL SAVINGS [%]		**2.7%**	**4.2%**	**4.5%**

Table 5.22 – Observed Daily Benefits of Imbalance Netting Implementation for UA

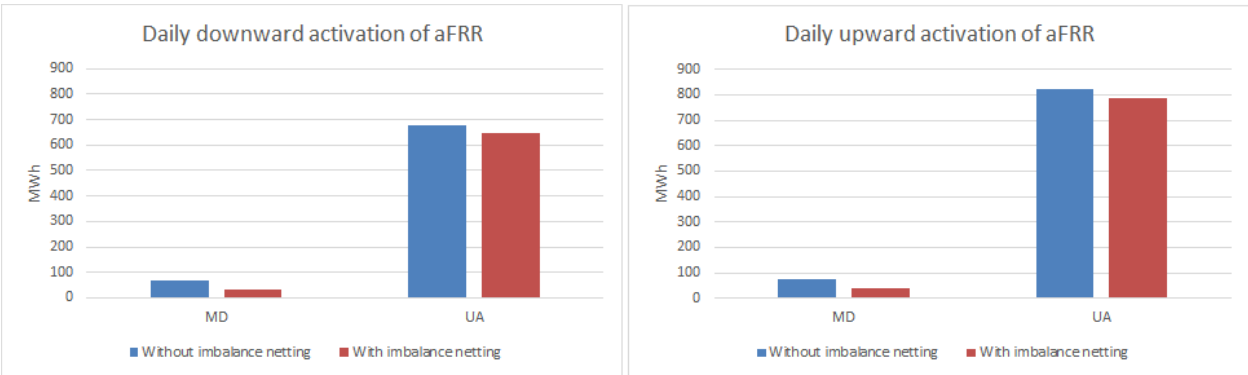

Figure 5.35 – Upward and Downward Activation of aFRR

MD&UA		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	31372	44821	61267
	Downward regulation cost [$]	-1187	-1934	-2849
	Total cost [$]	30185	42887	58418
WITH IMBALANCE NETTING	Upward regulation cost [$]	29654	41246	55395
	Downward regulation cost [$]	-1078	-1722	-2509
	Total cost [$]	28577	39523	52886
POTENTIAL SAVINGS [$]		**1609**	**3363**	**5532**
POTENTIAL SAVINGS [%]		**5.3%**	**7.8%**	**9.5%**

Table 5.23 – Observed Benefits of Imbalance Netting Implementation

By analyzing the results, the Study concludes the following:

- Activation of upward aFRR energy is decreased by 7.7%.
- Activation of downward aFRR energy is decreased by 9.3%.
- Total activation of aFRR energy is decreased by 8.5%, and therefore an unnecessary level of generator engagement for frequency restoration is avoided.
- For each of the six scenarios, the saving potential (monetary) observed for sub-region C is positive, and varies between 1.6 and 5.5 thousand USD/day, i.e. between 5% and 9.5%.
- In cases where both positive and negative directions of activated aFRR are quantified within the settlement period without cumulating (no "netting in time"), the observed benefits are the highest and always positive for each TSO participating in the process.
- In order to quantify the yearly savings potential as a result of imbalance netting in sub-region C, an additional detailed analysis is needed after the establishment of all national balancing markets with clear price signals for aFRR activated energy, and available data regarding power system imbalances for a longer period of time (1 to 2 years).
- Nevertheless, the analysis performed in this study provides a clear positive signal resulting from the implementation of imbalance netting in sub-region C, with potential annual savings that can be roughly estimated at a level of 0.6 to 2 million of USD depending on the applied aFRR energy measuring and pricing rules.

"Cost Based" Sensitivity Analysis

Considering the BSRI average balancing prices for Armenia, Georgia, Moldova and Ukraine given in Table 3.6, the following direct benefits of imbalance netting for all three cases for Moldova and Ukraine (sub-region C) were obtained (Table 5.24).

MD		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	1304	2272	3167
	Downward regulation cost [$]	-171	-343	-492
	Total cost [$]	1133	1929	2675
WITH IMBALANCE NETTING	Upward regulation cost [$]	859	1504	1781
	Downward regulation cost [$]	-69	-176	-222
	Total cost [$]	790	1328	1559
POTENTIAL SAVINGS [$]		343	601	1116
POTENTIAL SAVINGS [%]		30.3%	31.2%	41.7%

UA		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	18332	25391	34607
	Downward regulation cost [$]	-2030	-3206	-4742
	Total cost [$]	16303	22184	29865
WITH IMBALANCE NETTING	Upward regulation cost [$]	17837	24310	33034
	Downward regulation cost [$]	-1985	-3064	-4518
	Total cost [$]	15852	21246	28516
POTENTIAL SAVINGS [$]		451	938	1349
POTENTIAL SAVINGS [%]		2.8%	4.2%	4.5%

MD&UA		CASE 1	CASE 2	CASE 3
WITHOUT IMBALANCE NETTING	Upward regulation cost [$]	19636	27662	37774
	Downward regulation cost [$]	-2201	-3549	-5234
	Total cost [$]	17435	24113	32539
WITH IMBALANCE NETTING	Upward regulation cost [$]	18696	25814	34815
	Downward regulation cost [$]	-2054	-3240	-4740
	Total cost [$]	16642	22574	30075
POTENTIAL SAVINGS [$]		793	1539	2464
POTENTIAL SAVINGS [%]		4.5%	6.4%	7.6%

Table 5.24 – Summary of Observed Daily Benefits of Imbalance Netting Implementation (Cost Based Approach MD & UA))

The total potential absolute savings for both TSOs are approximately 60% lower in comparison with the so called "market based" approach which is expected when taking into account the narrow range of upward and downward regulation prices:

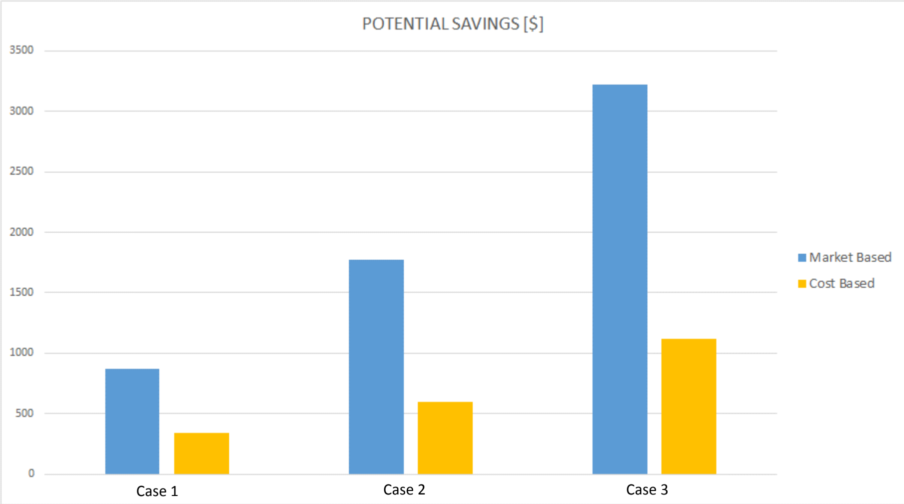

Table 5.25 – Market and Cost Based Potential Savings Per Case

However, it is important to note that relative savings (in %) are similar in both approaches.

The application of **imbalance netting** as a model of balancing markets integration presents the model primarily applied in the ENTSO-E community due to its effectiveness and simplicity.

In this analyses, the estimated benefits reach almost 50% of total aFRR costs in case of full netting on the 2 seconds level. In case of additional netting in time (to 15-minute or 1-hour level) these benefits are decreased.

Sub-region	TSO	Imbalance netting daily savings	
		USD	(%)
A1	Armenia	2928	36
	Georgia	3945	24
A2	Georgia	7330	44
	Turkey	7003	3.5
B	Bulgaria-	12793	50
	Romania	16408	44
	Turkey	30347	15
C	Moldova	3220	43
	Ukraine	2311	4.5

The estimated benefits show the high impact of the size of participating TSOs, enabling higher benefits in case of participating TSOs of similar size.

It should be noted that the total benefits include increased benefits from a reduction of upward activation of aFRR and reduced benefits from reduced downward activation of aFRR.

In case of the “cost based” approach, due to a narrow range of upward and downward balancing energy prices, the absolute imbalance netting benefits are significantly reduced but relative benefits are almost the same.

Sub-region	TSO	Imbalance netting daily savings	
		USD	(%)
A1	Armenia	1499	38
	Georgia	1619	23
C	Moldova	1116	42
	Ukraine	1349	4.5

Figure 5.36 – Imbalance Netting Daily Savings

5.2.2 Calculation of Direct Benefits of Secondary Control Exchange

The primary goal of this analysis is to quantitatively estimate the benefits when establishing a common mechanism for the exchange of balancing energy from automatic FRR (secondary control).

The analysis is based on a comparison between the total costs of local balancing mechanisms operating separately and total costs of the common balancing mechanism after the integration.

The local balancing mechanisms assume the activation of aFRR by national merit order lists of balancing energy. However, at the regional level, a mechanism of a common merit order list is used as explained in Chapters 3.1.2 and 3.2.4.

The analysis of the common balancing mechanism comprises both the positive influences of imbalance netting together with the activation optimization function and the common merit order list. The results for all sub-regions show that the effect resulting from netting of the activations is significantly higher than just implementation of the common merit order list, especially in cases where difference in prices are small.

Sub-region A1 – Simulation Results

An overview of the total monthly and yearly costs for the analyzed balancing mechanisms is given in Table 5.26, while an estimated total benefit of integration between Armenia and Georgia is shown in Table 5.27.

aFRR	National balancing market		National balancing market		Joint balancing market (with common merit order list)	
	AM		GE			
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	300132	-9701	681492	-24476	271580	-6419
February	262379	-7240	626583	-21358	233811	-5804
March	238525	-7345	680705	-24371	247408	-5930
April	206030	-5404	612168	-22550	222919	-5409
May	208301	-5750	537861	-17444	220769	-4559
June	205385	-5808	470563	-18464	195654	-5017
July	256986	-6835	536271	-17691	209625	-4922
August	250517	-6806	524991	-17328	221581	-4922
September	236229	-6843	525879	-15518	231549	-4959
October	209241	-5539	504353	-16877	199690	-4213
November	244921	-6855	539597	-18332	220140	-5015
December	285675	-9287	668287	-23478	250527	-6269
TOTAL/YEAR	**2,904,320**	**-83,412**	**6,908,748**	**-237,887**	**2,725,253**	**-63,438**

Table 5.26 – Overview of Costs for Activation of aFRR in Sub-Region A1

aFRR	National balancing market	National balancing market	Joint balancing market (with common merit order list)
	AM	GE	
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**2,820,908**	**6,670,861**	**5,919,672**
Potential saving (%)			**37.6%**

Table 5.27 – Benefits of Balancing Market Integration of aFRR Exchange between Sub-Region A1 TSOs

The estimated benefit of integration between Armenia and Georgia equates approximately 3.5 million USD at the yearly level, which is 37% of total costs of local balancing markets when operating separately. Within these benefits, the netting benefits are at the level of 30%.

Sub-region A2 – Simulation Results

The overview of total monthly and yearly costs for the analyzed balancing mechanisms as well as an estimated total benefit of integration between Turkey and Georgia is shown in the tables below:

aFRR	National balancing market		National balancing market		Joint balancing market (with common merit order list)	
	GE		TR			
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	681492	-24476	17390521	-450068	16487138	-435724
February	626583	-21358	15199111	-446687	14345074	-435126
March	680705	-24371	17237829	-457895	16290851	-434571
April	612168	-22550	15256770	-394438	14359267	-374134
May	537861	-17444	16513924	-418070	15564629	-398930
June	470563	-18464	14981698	-402188	14033663	-376894
July	536271	-17691	17698217	-479344	16765022	-459077
August	524991	-17328	18638801	-532168	17606087	-511756
September	525879	-15518	16413673	-435450	15503725	-422355
October	504353	-16877	15626913	-423911	14760123	-408448
November	539597	-18332	15982195	-444036	15049060	-421675
December	668287	-23478	17116199	-482723	16168260	-459583
TOTAL/YEAR	**6,908,748**	**-237,887**	**198,055,852**	**-5,366,978**	**186,932,899**	**-5,138,273**

Table 5.28 – Overview of Costs for Activation of aFRR in Sub-Region A2

aFRR	National balancing market	National balancing market	Joint balancing market (with common merit order list)
	GE	TR	
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**6,670,861**	**192,688,873**	**181,794,626**
Potential saving (%)			**8.8%**

Table 5.29 – Benefits of Balancing Market Integration of aFRR Exchange between Sub-Region A2 TSOs

The estimated benefit of integration between Turkey and Georgia equates approximately 17.5 million USD on yearly level, which is almost 9% of the total costs of local balancing markets when they are operating separately. The percentage of potential saving is not as high as in case of a joint AM-GE balancing market which is the consequence of significantly different size and characteristics of the power systems in case of sub-region A2. The netting benefits are on the level of 4%.

Sub-region B – Simulation Results

The overview of total monthly and yearly costs for the analyzed balancing mechanisms as well as an estimated total benefit of integration between Bulgaria, Romania and Turkey is shown in the tables below:

aFRR	National balancing market BG		National balancing market RO		National balancing market TR		Joint balancing market (with common merit order list)	
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	3327179	-121174	3299760	-103668	17390521	-450068	14351862	-328574
February	3266464	-112130	3355121	-77252	15199111	-446687	13522942	-314623
March	2963823	-97968	3229116	-67432	17237829	-457895	14983914	-304442
April	2485205	-78794	2948231	-62091	15256770	-394438	12890989	-273903
May	2230687	-62857	2730457	-73415	16513924	-418070	13596079	-282151
June	2115158	-62602	2809867	-62754	14981698	-402188	12779494	-272796
July	2441398	-78137	3322750	-77106	17698217	-479344	14709193	-318338
August	2509920	-74170	3245055	-87449	18638801	-532168	15394308	-357825
September	2380729	-76394	3194846	-67133	16413673	-435450	14034791	-302241
October	2551134	-78043	3497288	-72578	15626913	-423911	13432890	-279513
November	2604645	-76222	3033492	-89232	15982195	-444036	13285279	-304320
December	2913042	-104084	2968975	-92526	17116199	-482723	14150232	-340645
TOTAL/YEAR	**31,789,383**	**-1,022,575**	**37,634,957**	**-932,635**	**198,055,852**	**-5,366,978**	**167,131,973**	**-3,679,371**

Table 5.30 – Overview of Costs for Activation of aFRR in Sub-Region B

aFRR	National balancing market BG	National balancing market RO	National balancing market TR	Joint balancing market (with common merit order list)
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**30,766,808**	**36,702,322**	**192,688,873**	**163,452,601**
Potential saving (%)				**37.2%**

Table 5.31 – Benefits of Balancing Market Integration of aFRR Exchange between Sub-Region B TSOs

The Study concludes that the estimated benefit of integration between Bulgaria, Romania and Turkey equates approximately 97 million USD at the yearly level, which is 37% of total costs of local balancing markets operating separately. It should be noticed that within these benefits, netting benefits present a major part – around 31%.

Sub-region C – Simulation Results

An overview of the total monthly and yearly costs for analyzed balancing mechanisms as well as an estimated total benefit of integration between Moldova and Ukraine is shown in the tables below:

aFRR	National balancing market MD		National balancing market UA		Joint balancing market (with common merit order list)	
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	477049	-12092	9291051	-334929	9362634	-328436
February	423798	-12781	8786167	-289475	8762502	-282941
March	421701	-9477	8284404	-276387	8326729	-270554
April	387889	-9485	7018887	-234459	7013916	-224473
May	393807	-9142	6306511	-172415	6331323	-167358
June	397919	-8994	5757584	-171702	5779991	-167000
July	407214	-9443	5961942	-190562	5944467	-184774
August	385004	-8811	6097942	-169230	6076960	-164212
September	377722	-9460	5607204	-170604	5609976	-167465
October	407132	-9524	7189458	-225816	7211369	-215577
November	395742	-10703	7323178	-243271	7354511	-235955
December	473790	-11234	7487749	-273179	7479986	-265907
TOTAL/YEAR	**4,948,767**	**-121,144**	**85,112,080**	**-2,752,030**	**85,254,364**	**-2,674,652**

Table 5.32 – Overview of Costs for Activation of aFRR in Sub-Region C

aFRR	National balancing market MD	National balancing market UA	Joint balancing market (with common merit order list)
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**4,827,622**	**82,360,049**	**82,579,711**
Potential saving (%)			**5.3%**

Table 5.33 – Benefits of Balancing Market Integration of aFRR Exchange between Sub-Region C TSOs

The estimated benefit of integration between Moldova and Ukraine equates approximately 5 million USD at the yearly level, which is 5% of the total cost of the local balancing markets when they are operating separately. The benefits that can be expected when there is a joint operation of balancing markets in the case of sub-region C are the lowest due to the differences in the size and characteristics of power systems of Moldova and Ukraine.

The majority of the benefits result from activation netting – almost 4%.

The application of **cross-border exchange of balancing energy from aFRR** as a model of balancing markets integration provides benefits that are lower than estimated benefits from imbalance netting while at the same time requiring higher levels of balancing products harmonization between participating TSOs. In case of imbalance netting, the sizes and characteristics of participating TSOs have a significant impact on the level of possible benefits. However, in the case of the balancing markets integration model, the levels of prices are also important since in case of similar prices, the effects and potential benefits are limited.

The benefits are estimated for netting of counter activation and implementation of the common merit order list.

Sub-region	TSO	Costs of individual activation of aFRR	Costs in case of exchange of balancing energy from aFRR	Savings due to exchange of balancing energy from aFRR	
		Million USD	Million USD	Million USD	(%)
A1	Armenia	2.8	5.9	3.6	37
	Georgia	6.7			
A2	Georgia	6.7	181.8	17.6	9
	Turkey	192.7			
B	Bulgaria-	30.8	163.4	96.8	37
	Romania	36.7			
	Turkey	192.7			
C	Moldova	4.8	82.6	4.6	5
	Ukraine	82.4			

The savings realized through a reduction of upward activation of aFRR are positive while savings realized through a reduction of downward activation of aFRR are negative.

Figure 5.37 – aFRR Costs of Individual Activation, Exchange of Balancing Energy and Resulting Savings

5.2.3 Calculation of Direct Benefits of Tertiary Control Exchange

The estimation of the potential benefits of balancing market integration from mFRR/RR (tertiary control) exchange between TSOs is performed with the same approach and assumptions used in the previous chapter. As a direct consequence of balancing market integration, analysis comprises the following two positive aspects for potential benefits:

- Imbalance netting of counter activations of mFRR/RR
- Merging of national merit order lists into a common merit order list

Sub-region A1 – Simulation Results

The total costs for mFRR/RR for each month and for the whole year as well as the potential benefits of integration are shown in the figures below:

mFRR/RR	National balancing market		National balancing market		Joint balancing market (with common merit order list)	
	AM		GE			
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	626928	-58267	1680494	-163340	1303072	-175047
February	659055	-45395	1647787	-146403	1318492	-152497
March	547171	-51137	1542294	-139971	1312050	-160732
April	554137	-53696	1518056	-161628	1200179	-164082
May	564280	-43262	1307198	-120263	1040521	-126954
June	505675	-48936	1178877	-123854	1052310	-149881
July	597573	-46151	1146971	-117012	1052396	-135117
August	612626	-55030	1322873	-127423	1144226	-145792
September	542288	-46651	1116315	-122057	1005921	-151938
October	586114	-43498	1256278	-114384	1145910	-141118
November	608010	-51712	1495275	-159510	1203108	-171959
December	725546	-60694	1698912	-159789	1380825	-178883
TOTAL/YEAR	**7,129,403**	**-604,430**	**16,911,331**	**-1,655,633**	**14,159,010**	**-1,854,000**

Table 5.34 – Overview of Costs for Activation of mFRR/RR in Sub-Region A1

Manual FRR	National balancing market	National balancing market	Joint balancing market (with common merit order list)
	AM	GE	
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**6,524,973**	**15,255,697**	**12,305,010**
Potential saving (%)			**43.5%**

Table 5.35 – Benefits of Balancing Market Integration of mFRR/RR Exchange between Sub-Region A1 TSOs

The potential benefits of balancing market integration for mFRR/RR exchange between Armenia and Georgia are about 9.5 million USD which is approximately 43% of the total cost when implementing individual balancing markets. This benefit is more than two times higher when compared to the integration of Armenia and Georgia for aFRR exchange. This implies that mFRR/RR activates substantially higher amounts of balancing energy than aFRR and therefore should have a higher priority on the future regional balancing integration roadmap.

In this case, the netting benefit is on the level of 11%.

Sub-region A2 – Simulation Results

The total costs for mFRR/RR for each month and for the whole year as well as the potential benefits of integration are shown in the tables below.

mFF/RR	National balancing market GE		National balancing market TR		Joint balancing market (with common merit order list)	
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	1680494	-163340	25059126	-2294841	23149765	-2024536
February	1647787	-146403	24657498	-1952670	22475724	-1729105
March	1542294	-139971	24664739	-2017013	22732218	-1792475
April	1518056	-161628	22924666	-1998012	20983108	-1797677
May	1307198	-120263	25160696	-2031938	23093362	-1802227
June	1178877	-123854	23827715	-1916930	21806981	-1797298
July	1146971	-117012	31617256	-2382553	28641054	-2084068
August	1322873	-127423	31839408	-2712665	29100516	-2383371
September	1116315	-122057	26397436	-2047167	24119873	-1828476
October	1256278	-114384	24141700	-2203240	21855857	-1955001
November	1495275	-159510	25258052	-2034306	23017134	-1842332
December	1698912	-159789	29917929	-2587383	27046498	-2246528
TOTAL/YEAR	**16,911,331**	**-1,655,633**	**315,466,220**	**-26,178,717**	**288,022,090**	**-23,283,095**

Table 5.36 – Overview of Costs for Activation of mFRR/RR in Sub-Region A2

mFRR/RR	National balancing market GE	National balancing market TR	Joint balancing market (with common merit order list)
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**15,255,697**	**289,287,503**	**264,738,995**
Potential saving (%)			**13.1%**

Table 5.37 – Benefits of Balancing Market Integration of mFRR/RR Exchange between Sub-Region A2 TSOs

The potential benefits of balancing market integration for mFRR/RR exchange between Turkey and Georgia are approximately 40 million USD which is about 13% of the total costs in the case of individual balancing markets. As in case of sub-region A1, this benefit is more than two times higher when compared to the integration of Turkey and Georgia for aFRR exchange, which implies that mFRR/RR activates substantially higher amounts of balancing energy than aFRR. In this case, the netting benefit is on the level of 4%.

Sub-region B – Simulation Results

The total costs for mFRR/RR for each month and for the whole year as well as the potential benefits of integration are shown in the tables below.

mFRR/RR	National balancing market BG		National balancing market RO		National balancing market TR		Joint balancing market (with common merit order list)	
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	3551374	-1699216	19299254	-338599	25059126	-2294841	34527290	-1339790
February	3550729	-1327121	11728192	-398318	24657498	-1952670	28152819	-1394344
March	2815823	-1288965	11782797	-704025	24664739	-2017013	27237025	-1846783
April	2494335	-1042760	8962695	-1254212	22924666	-1998012	20852876	-2259564
May	1908756	-836886	6646181	-873252	25160696	-2031938	20465550	-1789837
June	2438976	-749925	8870744	-485082	23827715	-1916930	24153027	-1261527
July	2569519	-909159	27694225	-167632	31617256	-2382553	46053097	-856799
August	2231600	-922747	18151061	-504794	31839408	-2712665	36417606	-1265612
September	2431023	-893664	14835061	-305908	26397436	-2047167	31371402	-1088699
October	2181083	-1045794	13873799	-242706	24141700	-2203240	29713689	-1235207
November	2277759	-1093101	15692002	-434810	25258052	-2034306	30776368	-1305343
December	3101765	-1166063	16668498	-646173	29917929	-2587383	33429301	-1499247
TOTAL/YEAR	**31,552,743**	**-12,975,403**	**174,204,508**	**-6,355,512**	**315,466,220**	**-26,178,717**	**363,150,051**	**-17,142,752**

Table 5.38 – Overview of Costs for Activation of mFRR/RR in Sub-Region B

mFRR/RR	National balancing market BG	National balancing market RO	National balancing market TR	Joint balancing market (with common merit order list)
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**18,577,340**	**167,848,997**	**289,287,503**	**346,007,299**
Potential saving (%)				**27.3%**

Table 5.39 – Benefits of Balancing Market Integration of mFRR/RR Exchange between Sub-Region B TSOs

The potential benefits of balancing market integration for mFRR/RR exchange between Bulgaria, Romania and Turkey are approximately 130 million USD which equates 27% of the total costs when implementing individual balancing markets. Similar to the previous cases, due to higher activations of mFRR/RR reserves, this benefit is more than two times higher when compared to the integration of these systems for aFRR exchange.

Sub-region C – Simulation Results

The total costs for mFRR/RR for each month and for the whole year as well as the potential benefits of integration are shown in the tables below.

mFRR/RR	National balancing market MD		National balancing market UA		Joint balancing market (with common merit order list)	
	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]	Upward regulation [USD]	Downward regulation [USD]
January	703746	-49120	19955837	-1956798	19297484	-1715189
February	621645	-54424	18977120	-1947856	18287163	-1713383
March	591002	-58039	18697098	-1906952	17795171	-1683615
April	594485	-56946	15153897	-1542722	14683561	-1388855
May	673054	-46336	14220163	-1480783	13685055	-1306689
June	672465	-52777	14502035	-1518770	13992758	-1356047
July	718352	-45616	14235598	-1662645	13984762	-1464504
August	674243	-47095	14256905	-1421207	13788374	-1270809
September	720316	-40359	14190453	-1471918	13838116	-1286194
October	663250	-54911	16630972	-1591998	16047632	-1425525
November	650267	-49579	16056243	-1606582	15473221	-1451795
December	685677	-48495	16035502	-1563652	15305981	-1403548
TOTAL/YEAR	**7,968,501**	**-603,696**	**192,911,823**	**-19,671,883**	**186,179,278**	**-17,466,153**

Table 5.40 – Overview of Costs for Activation of mFRR/RR in Sub-Region C

mFRR/RR	National balancing market	National balancing market	Joint balancing market (with common merit order list)
	MD	UA	
	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]	Upward & Downward regulation [USD]
TOTAL/YEAR	**7,364,805**	**173,239,940**	**168,713,125**
Potential saving (%)			**6.6%**

Table 5.41 – Benefits of Balancing Market Integration of mFRR/RR Exchange between Sub-Region C TSOs

The potential benefits of balancing market integration for mFRR/RR exchange between Moldova and Ukraine are approximately 12 million USD which equates 6.6% of total costs in the case of the individual balancing markets. As in the case of other sub-regions, this benefit is more than two times higher when compared to the integration of Moldova and Ukraine for aFRR exchange. This implies that mFRR/RR activates substantially higher amounts of balancing energy than the aFRR and therefore should have a higher priority on the future regional balancing integration roadmap. In this case, the netting benefit is on the level of 3%.

The application of **cross-border exchange of balancing energy from mFRR/RR** provides the benefits for all participating TSOs. As in case of aFRR energy exchange, the level of prices is important since in the case of similar prices, the effects and potential benefits are limited. Also, the lowest benefits are gained in case of integration of balancing markets of the TSOs of different sizes and characteristics.

The benefits are estimated for both netting of counter activation and implementation of the common merit order list.

Sub-region	TSO	Costs of individual activation of mFRR/RR	Costs in case of exchange of balancing energy from mFRR/RR	Savings due to exchange of balancing energy from mFRR/RR	
		Million USD	Million USD	Million USD	(%)
A1	Armenia	6.5	12.3	9.5	43
	Georgia	15.3			
A2	Georgia	15.3	264.7	39.9	13
	Turkey	289.3			
B	Bulgaria-	18.6	346.0	129.7	27
	Romania	167.8			
	Turkey	289.3			
C	Moldova	7.4	168.7	11.9	7
	Ukraine	173.2			

As in the case of aFRR exchange, the savings realized through a reduction of upward activation of aFRR are positive while savings realized through a reduction of downward activation of aFRR are negative.

Figure 5.38 – mFRR/RR Costs of Individual Activation, Exchange of Balancing Energy and Resulting Savings

6 BSTP CONCLUSIONS AND NEXT STEPS

The objective of this Report is to provide an estimate of the potential for integrating system balancing resources in the Black Sea region as a medium term solution to system optimization. The limiting factor in this analysis is the current status of the national balancing markets, status of the unbundling process and wholesale market development in the region as well as a lack of corresponding measurements and data.

The results presented in this report are rough and indicative as numerous assumptions and estimations have been applied. Changes to the input dataset may materially change the outputs. However, these limitations should not significantly impact the conclusions.

As cross-zonal limitations are not taken into account, the Study benefits may be overestimated. This will be the task for TSOs and regulators to analyze in detail during the trade-off of the cross-border capacity reservations, benefits and losses in whole-sale and balancing markets.

The results show that all the measures investigated in this report appear significantly beneficial in terms of system costs: in some cases, the benefits are higher than 60% of the total corresponding costs (common dimensioning model). However, the high benefits require high levels of harmonization of balancing markets which may be considered questionable or may be considered as long-term actions.

Conversely, there is a model of balancing markets integration that provides high benefits with low requirements for harmonization among participating TSOs – imbalance netting. This model provides maximal savings at the level of 50% of total corresponding costs. The imbalance netting model of cross-border balancing cooperation could be the first to be implemented in the Black Sea region. This model is easily implemented. In addition, the EU and ENTSO-E countries are experienced in its implementation as the model has been used for more than a decade.

Assuming the modelling is representative and by increasing the flexibility of the power system, strengthening regional cooperation and pulling additional resources into the market, the overall cost of the power system would reduce, to the ultimate benefit of citizens and businesses. As presented in the first Phase of the Study, a number of ongoing initiatives and pilot projects are already exploiting the benefits emerging from a tighter collaboration between TSOs. These experiences should be used to initiate the cross-border balancing cooperation in the Black Sea region as well.

Further refinement of the assumptions, proxies and input data have been carried out in cooperation with NARUC and BSRI regulators and results have been presented through the additional sensitivity analyses sections added to the Calculation of Direct Benefits of: Common Dimensioning of Reserve, Sharing of Reserve and Imbalance netting. As the appropriate estimated reserves and balancing energy prices were the result of the applied BSRI "cost based" approach, their level was lower than the BSTP "market based" figures and this implied lower absolute benefit effects. However, in terms of relative values, the percentages were nearly the same or slightly lower which confirmed that data limitations should not significantly impact the main conclusions.

The considered market–based approach provides indications about the sub-regional long-term benefits resulting from coupling of ancillary services (particularly balancing services) when competitive markets will be developed in Armenia, Georgia, Moldova, and Ukraine. However, pricing ancillary services in an electricity market requires an effective market structure with sound performance. In the Armenia-Georgia and Moldova-Ukraine sub-regions, prospective electricity markets are not yet ready to support competitive balancing and ancillary services. Therefore, it is not advisable to move directly to market-based pricing of balancing and ancillary services in those countries. This is also emphasized in the BSRI Wholesale Market Guidelines.

It is commonly agreed by the BSRI and BSTP stakeholders to calculate benefits from sub-regional coupling of balancing services based on cost-based approach (sensitivity analysis). The sensitivity analysis has been performed only for direct benefits of coupling of balancing reserves and energy. It is recommended to begin with direct benefits; (1) common dimensioning; (2) share of reserves, and; (3) imbalance netting at the sub-regional level, as in the case of EU countries. Sensitivity analysis have not included indirect benefit calculations which necessitate detailed market simulations. Nevertheless, the sub-regional level direct benefits should be the initial target to realize in BSRI countries (like in the EU countries).

Realization of direct benefits from balancing coupling requires common efforts between the TSOs and regulators both at the national and sub-regional level. Harmonization of balancing service rules including settlement mechanisms are among the key issues to be addressed in the region. Separation of balancing service costs, determination of true-costs of balancing services, identification and pre-qualification of balancing service providers (BSP), and identification of settling mechanisms between the countries are among the initial steps that regulators should focus on.

7 BSRI CONCLUSIONS AND RECOMMENDATIONS

Pricing ancillary services in an electricity market requires an effective market structure with sound performance. In the Black Sea region, prospective electricity markets are not yet ready to support competitive balancing and ancillary services. Therefore, it is not advisable to move directly to "market-based" pricing of balancing and ancillary services in BSRI countries. This is also emphasized in the BSRI Wholesale Market Guidelines. Even though an efficient wholesale competition is a critical goal, until competitive wholesale markets are in place, there is a need to address the following three main issues:

1. Preconditions for participating in ancillary services supply at "cost-based" rates.
2. How to develop cost-based rates for ancillary services and balancing.
3. How regulators determine when the market is ready for "market-based" procurement and how to monitor such markets.

Recommendations for addressing these issues at the region are presented in the table below, along with the recommended implementation periods.

	Recommendations (Recommended implementation period; 1 - Short-term; 2 - Mid-term; 3 - Long-term)	Period
Policy level:		
-	Procurement of balancing and other ancillary services should start based on "cost-based approaches"	1
-	Hourly-based day ahead market should be created by law start (although functioning will start with cost-based approach).	2
-	Unbundling of MO and TSO in practice. Operation of the balancing market by the MO even at cost-based approach period until a competitive market develops.	3
-	Coupling of balancing should start with "direct benefits" (Common dimensioning, share of reserves, and imbalance netting) from balancing reserve and energy. Common studies are necessary at sub-regional level to identify infrastructure needs, harmonization of balancing services rules including settling mechanism	3
Regulators should work with TSOs:		
-	To calculate true-cost of balancing reserve and energy	1
-	To define Balancing Responsible Parties (BRP) and their responsibilities in the grid code	1
-	Third party access tariffs/charges and their methodologies should be approved by the regulator. Methodology and tariffs should be public.	1
-	To develop a methodology for pricing balancing services separately and start pricing balancing services separately (even at cost-based approach).	2
-	To harmonize grid codes at subregional level. Harmonizing balancing services should be the initial step to expedite benefits from balancing coupling.	2
-	To coordinate with neighboring TSOs for determining NTCs and rules for allocating capacities (both directions) on the interconnection lines.	2
-	To develop/amend grid code	2
-	To define ancillary services other than balancing (e.g., reactive power support) in the grid code	3
Regulators should:		

-	Collect cost data of BSPs and calculate true-costs of balancing reserves ($/MW) and energy ($/MWh upward/downward aFRR, mFRR) for the cost-based approach (as an initial step until competitive markets develop).	1
-	Have an access to models TSO uses to monitor cross-border activities of TSO (NTC calculation and allocation).	2
-	Approve and publish: - Grid code - Methodology for choosing BSP (e.g., merit-order for the cost-based approach). - Methodology to calculate NTC (period and technical studies) - NTC calculation results - Methodology to allocate NTCs among interested market players (e.g., electronic auction mechanism in Georgia) - NTC allocation results	2
-	Define: - A methodology and KPIs for monitoring performance of TSO in terms of network security and reliability. - Define KPIs and necessary input data for monitoring investments in generation capacities in relation to security of supply.	2
-	Monitor: - TSO's prequalification/certification/monitoring process for ancillary services - Level and effectiveness of market opening and competition (even at the cost-based approach period) based on KPIs. - Investments in generation capacities in relation to security of supply. - Merit-order of the balancing suppliers (hourly resolution)	3
TSOs should:		
-	Technically prequalify entities as Balancing Service Providers (BSPs) through a certification mechanism.	1
-	Provide input data to regulators for calculating KPIs in the scope of monitoring performance of network security and reliability	2
MOs should:		
-	Provide hourly-based merit-order to the regulator for monitoring. Merit order is critical for the cost-based approaches in terms of monitoring the cost of balancing reserves.	2
-	Publish hourly-based wholesale prices	2
Policy level:		
-	Procurement of balancing and other ancillary services should start based on "cost-based approaches"	1
-	Hourly-based day ahead market should be created by law start (although functioning will start with cost-based approach).	2
-	Unbundling of MO and TSO in practice. Operation of the balancing market by the MO even at cost-based approach period until a competitive market develops.	3
-	Coupling of balancing should start with "direct benefits" (Common dimensioning, share of reserves, and imbalance netting) from balancing reserve and energy. Common studies are necessary at sub-regional level to identify infrastructure needs, harmonization of balancing services rules including settling mechanism	3

Table 7.1 Short-, mid-, and long-term recommendations and for addressing the main issues in the region

Recommendation 1

Until competitive balancing markets develop in the region, cost-based approaches necessitate the determination of tariffs, which reflect true costs of balancing services, as illustrated in Figure 7.1. TSOs and regulators need to work together in determining the true costs of balancing services. Accurate pricing of balancing services in cost-based approaches depend on how close these coordination's are. As illustrated in Figure 7.2, TSOs should focus more on the technical requirement aspects of balancing services for their transmission grid. These mainly include; (1) determining the necessary amount of balancing reserves in terms of FCR, aFRR and mFRR for different time horizons (daily, weekly, monthly, seasonally, and annually); (2) availability of different types of reserves; (3) upward/downward activation time requirements of balancing reserves. Conversely, regulators should also focus more on commercial and regulatory requirement aspects of balancing services. These mainly include; (1) calculations of true costs of balancing reserves ($/MW) and activation of the reserves ($/MWh); (2) identification of cost-based tariffs for balancing services; (3) defining settling mechanisms at the sub-regional level; (4) approval of the tariffs and mechanisms.

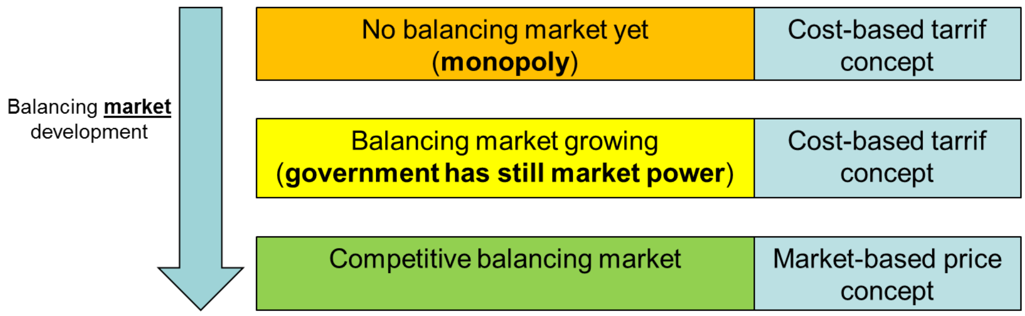

Figure 7.1 Development of the Balancing Market at the BSRI Countries.

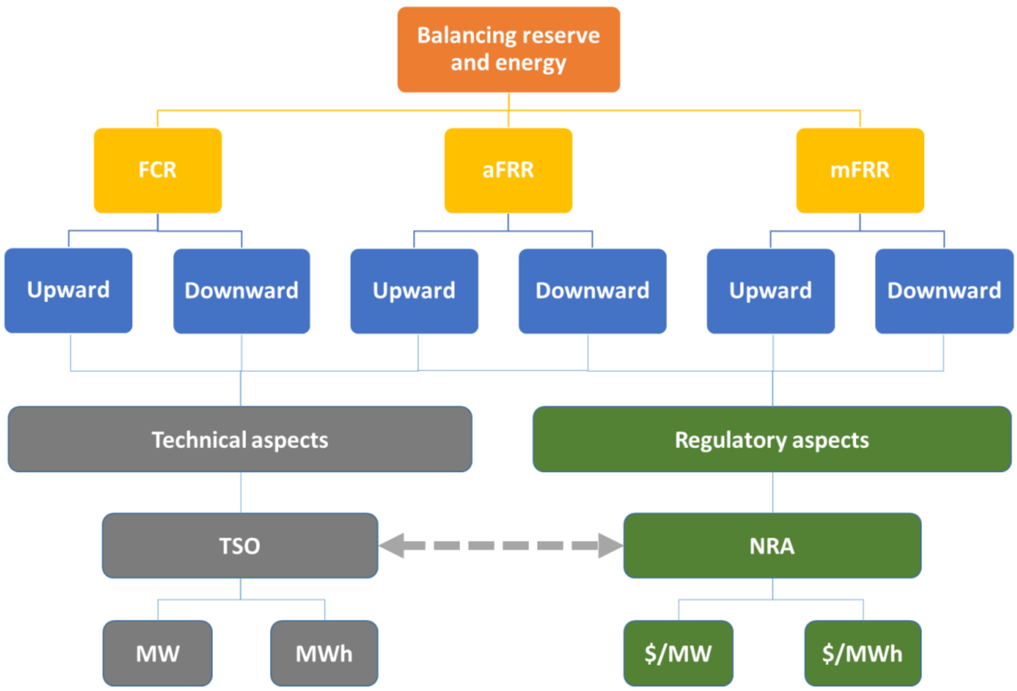

Figure 7.2 Breakdown of Balancing Services and Main Roles of TSOs and NRAs.

Recommendation 2

In addition, TSOs and regulators should coordinate at the sub-regional level to ensure common understanding from cross border common usage of balancing services and to define a settling mechanism (Figure 7.3). The sensitivity analysis, which was performed in collaboration of the NRAs in the BSRI Project and TSOs in the BSTP Project, is a good example which demonstrates benefits of such coordination.

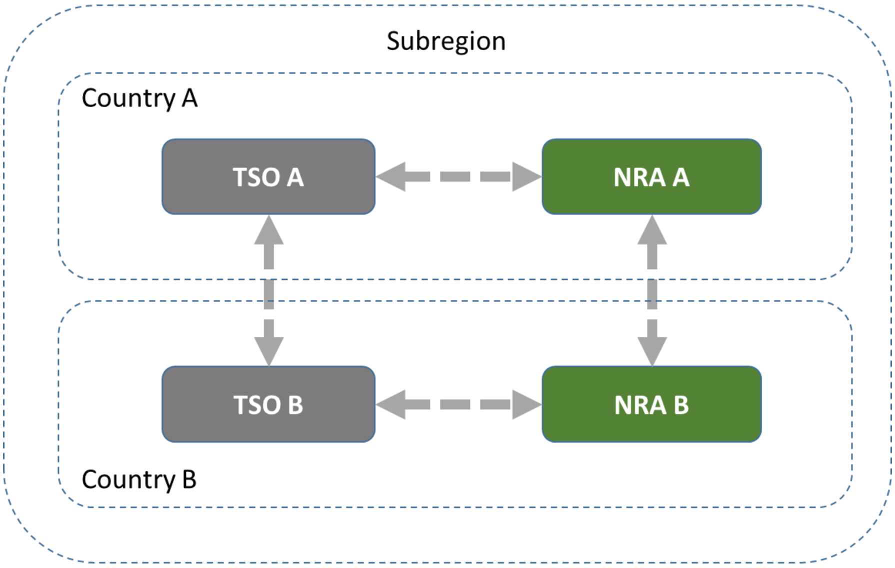

Figure 7.3 Necessary Coordination between the TSO and NRA at the Country Level and TSOs, NRAs at Sub-regional Level.

Recommendation 3

Distinguishing the roles of data collection between the TSO and the NRA is important as regulators are able to circumvent commercial sensitivities that may reside in TSO data collection and calculation – e.g., power generating companies can conceal critical data which might be important from the TSO's perspective for estimating costs. NRAs can collect the data by exercising their authority. The NRAs' capabilities in calculating true costs of balancing capacity and reserve activation, and their contribution in assessing bilateral contracts for balancing capacity will improve their authority. This is particularly true from the perspective of TSOs, generation companies, and the ministry. It is recommended that until competitive markets develop, NRAs should be responsible for the collection of cost data from the power plants through their authority and approve the corresponding tariffs for balancing prices based on cost-based approach.

Conclusions

The market–based approach considered in the BSTP project essentially gives indications about the sub-regional benefits of the countries. The findings support that coupling of ancillary services (particularly balancing services) in the long run will serve to benefit the countries when competitive markets will be developed in Armenia, Georgia, Moldova, and Ukraine. However, pricing ancillary services in an electricity market requires an effective market structure with sound performance. In the Armenia-Georgia and Moldova-Ukraine sub-regions, prospective electricity markets are not yet ready to support competitive balancing and ancillary services. Therefore, it is not advisable to move directly to market-based pricing of balancing and ancillary services in those countries. This is also emphasized in the BSRI Wholesale Market Guidelines.

It is commonly agreed by the BSRI and BSTP stakeholders to calculate benefits from the sub-regional coupling of balancing services on a cost-based approach as well (sensitivity analysis). A sensitivity analysis will be performed only for the direct benefit of coupling of balancing reserves and energy. It is recommended to start with benefitting from direct benefits; (1) common dimensioning; (2) share of reserves; and (3) imbalance netting at the sub-regional level, as in the case of EU countries. A sensitivity analysis will not include indirect benefit calculations which necessitate detailed market simulations. Nevertheless, the sub-regional level direct benefits should be the initial target to realize in BSRI countries (like in the EU countries).

The direct benefits from balancing coupling requires common efforts between the TSOs and regulators both at the national and sub-regional level. Harmonization of balancing service rules including settlement mechanisms is among the key issues to be addressed in the region. Separation of balancing service costs, determination of true-costs of balancing services, identification and pre-qualification of balancing service providers, and identification of settling mechanisms between the countries are among the initial steps that regulators should focus on.

In order to expedite this process, regulators and TSOs can start utilizing "direct" benefits based on the cost-based approach at the sub-regional level. TSOs can work bilaterally at the sub-regional level, regarding the infrastructure needs at the dispatch centre for imbalance netting. Further, regulators can work on promoting direct benefits to policy makers and addressing legislative framework (including settling mechanisms between the countries). After the infrastructure is installed, countries can begin calculating the benefits based on real ACE values at the dispatch centre (test period). After legislation has been passed and settlement rules are established, countries can start benefitting from imbalance netting, as they would have already installed the infrastructure and would be capable of calculating the benefits and settling (implementation period).

There are several policy/regulatory gaps that should be addressed in the region. Although some of those issues are common in all countries (e.g., developing a methodology for pricing balancing services separately, amendment of grid codes to include identification of BSPs, etc.), some countries have accomplished significant steps if compared to others (e.g., NTC allocation mechanism in Georgia). This shows the potential for experience sharing between the countries.

8 REFERENCES

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9 BSTP APPENDIX

9.1 GTMax Model Details

9.1.1 Zones and Network Constraints (NTCs)

Most of the BSTP countries are identified as one area – one zone → "copper plate" entities which means that there is no congestion. And this was applied for the following power systems:

- Armenia
- Bulgaria
- Georgia
- Moldova
- Romania

One area was separated into the several zones only for:

- Turkey
- Ukraine

For Turkey, the main network bottlenecks are usually in the Northeast part of the country towards the rest of the system and the power system area was split in two congestion free zones:

A. Main part of Turkey
B. East of Turkey (or East Anatolia as TEIAS control area).

On the other side, since no critical transmission element is found, the Ukrainian transmission network is divided in 9 zones as this is how UKRENERGO normally operates. One zone is completely separated from other 8. It is so called "Burshtyn Island" which is synchronously connected with central Europe and ENTSO-E. The list of the zones is the following:

1. Donbas
2. North
3. Dnieper
4. Crimea
5. South
6. Burshtyn Island
7. Centre
8. South-West
9. West

Network constraints are, within generation analyses, taken as maximum commercial exchanges that can be realized between modelled bidding areas (countries). Maximum commercial exchanges are limited by the values of NTC (Net Transfer Capacity). These values are determined on the basis of the available data (ENTOS-E-TYNDP, previous studies, expert views) and calculations performed by BSTP members.

Zone I	Zone II	2020 WP peak NTC I to II [MW]	2020 WP NTC II to I [MW]
Armenia	Georgia	325	640
Armenia	Central Asia	1200	1200
Georgia	Turkey (B)	600	0
Georgia	IPS/UPS	700	700
Bulgaria	ENTSO-E	1000	1000
Romania	Bulgaria	1200	1450
Romania	ENTSO-E	1000	1000
Romania	Ukraine (6)	200	250
Moldova	Ukraine	700	700
Turkey (A)	Bulgaria	900	850
Turkey (A)	ENTSO-E	450	400
Turkey (A)	Turkey (B)	4200	4200
Ukraine (6)	ENTSO-E	650	450
Ukraine (1)	IPS/UPS	1000	1000
Ukraine (2)	IPS/UPS	1000	1000
Ukraine (3)	IPS/UPS	1000	1000
Ukraine (1)	Ukraine (2)	900	300
Ukraine (1)	Ukraine (3)	1500	2500
Ukraine (2)	Ukraine (3)	500	550
Ukraine (2)	Ukraine (7)	650	750
Ukraine (3)	Ukraine (4)	300	0
Ukraine (3)	Ukraine (5)	4400	1150
Ukraine (3)	Ukraine (7)	500	400
Ukraine (3)	Ukraine (8)	300	500
Ukraine (4)	Ukraine (5)	0	850

Ukraine (5)	Ukraine (8)	300	900
Ukraine (7)	Ukraine (8)	1850	2350
Ukraine (7)	Ukraine (8)	600	1150
Ukraine (8)	Ukraine (9)	1450	1350

9.1.2 Generation and Demand

Zone	Installed capacities per technology in 2020 [MW]						January 3rd Week Consumption in 2020 [GWh]
	TPPs	NPPs	HPPs	Wind	Solar	Other	
Armenia	2207	400	1074	303	0	0	150.96
Bulgaria	5691	2080	2090	1101	1410	99	885.06
Georgia	1325	0	4045	21	0	0	248.75
Moldova	2672	0	45	252	20	0	132.74
Romania	9489	2630	7530	3899	2052	0	1143.49
Turkey (A)	48408	0	25077	7450	2507	588	6529.25
Turkey (B)	1583	0	5993	87	592	139	153.71
Ukraine (1)	11107	0	0	25	12	0	797.46
Ukraine (2)	2775	0	0	0	6	36	352.36
Ukraine (3)	8556	6000	2927	585	175	11	905.02
Ukraine (4)	280	0	0	870	468	0	148.36
Ukraine (5)	120	3000	604	630	228	35	341.24
Ukraine (6)	2414	0	0	50	9	1	126.11
Ukraine (7)	3294	0	1534	0	498	21	537.82
Ukraine (8)	1850	3000	1674	0	101	0	244.81
Ukraine (9)	1420	2000	0	0	142	10	255.93

9.1.3 Distant Systems

Distant systems that do not respond to changes in generation and market operation of BSTP power systems are modelled as spot markets with defined interconnection capabilities and wholesale prices assumed on the basis of current prices and trends from long-term derivatives ("futures"), assuming different levels for off-peak and peak prices. However, the main idea of the Study is to use them as export/import drivers for analysed sub-regions. There are three modelled spot markets with the following characteristics:

- Central Asia with 60 $/MWh in off-peak and 69 $/MWh in peak hours
- IPS/UPS with 59 $/MWh in off-peak and 70 $/MWh in peak hours
- ENTSO-E with 55 $/MWh in off-peak and 60 $/MWh in peak hours

10 BSRI APPENDIX

Table 10.1 Data Exchange and Transparency Needs

Data Category	Specific	Explanation	Regulator	TSO	MO	Producer/ Consumer
Meter Data	Consumption data	Consumption measured at the metering point	Monitoring and transparency	Grid Planning, Grid Operation, Network Tariff Allocation	Market operation, settlement	Owner of the data
	Production data	Production measured at the metering point				
	Contract	Contract(s) associated with the metering point, both energy and grid usage				
	Balance group	The balance group to which the metering point belongs				
Grid Data	Real-time data	Measurements of voltages, active and reactive injections or flows, frequency, power quality and grid-configuration	No use-case	Grid Planning, Grid Operation, Network Tariff Determination	No use-case	Market power
	Historic measurements	Historic grid measurements, such as voltage angle and magnitude, frequency and power flows	Monitoring and transparency			
	Planned grid configuration	Planned grid configuration for, e. g., the day ahead operation of grids	No use-case			
	Planned maintenance	Planned maintenance, including the associated changes to grid configuration, and start and end dates				Bidding strategy
	Known outages	Known outages affecting the grid configuration and/or the demand and generation				
	Cross-border capacity	Available transfer capacity that can be bid for	Monitoring and transparency			Bidding strategy
	Planned grid extentions	Planned expansions of grids and assets, usually with a long time horizon				Investment decision

Market Data	Weather data	Weather forecasts from one or more data suppliers	No use-case	Grid Operation, Balancing	No use-case	Offers
	Spot-market data	Results of the spot market	Monitoring and transparency		Owner of the data	Demand response
	Generation data	Data, such as type of generation, rating, availability and generation-specific parameters				Market power(only owned data allowed)
	Schedule data	Schedule of a balancing responsible party				
	Unit level cons/prod plan	Production and consumption plan per significant grid user (SGU)/grid location				
	Flexibility data	Data on location and type of flexibility source, results of tenders				

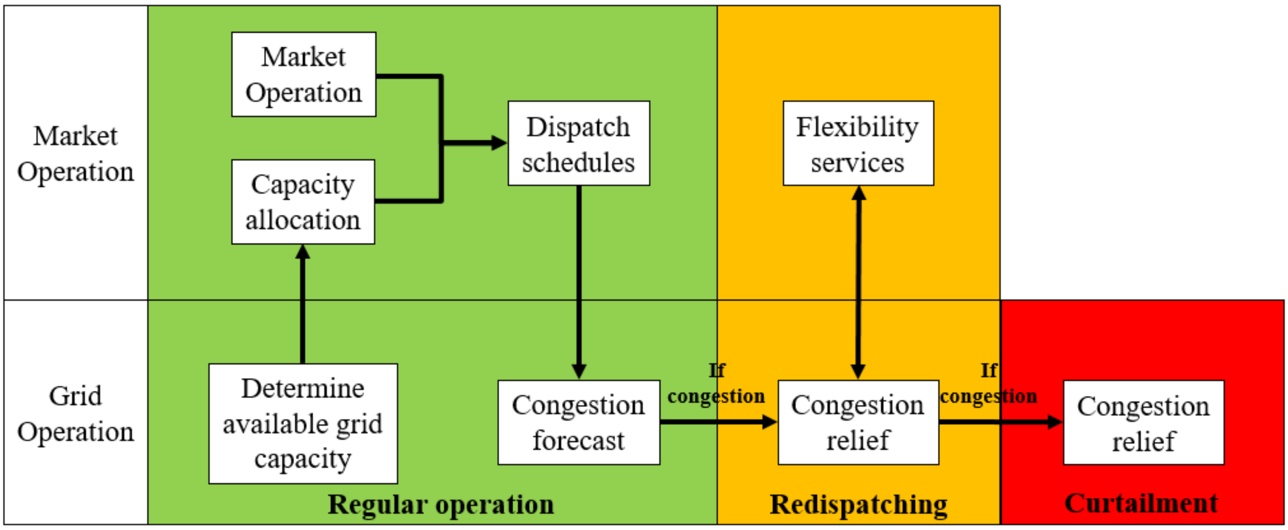

Figure 10.1. Utilization of TSO Data by NRA – Monitoring Congestion Management

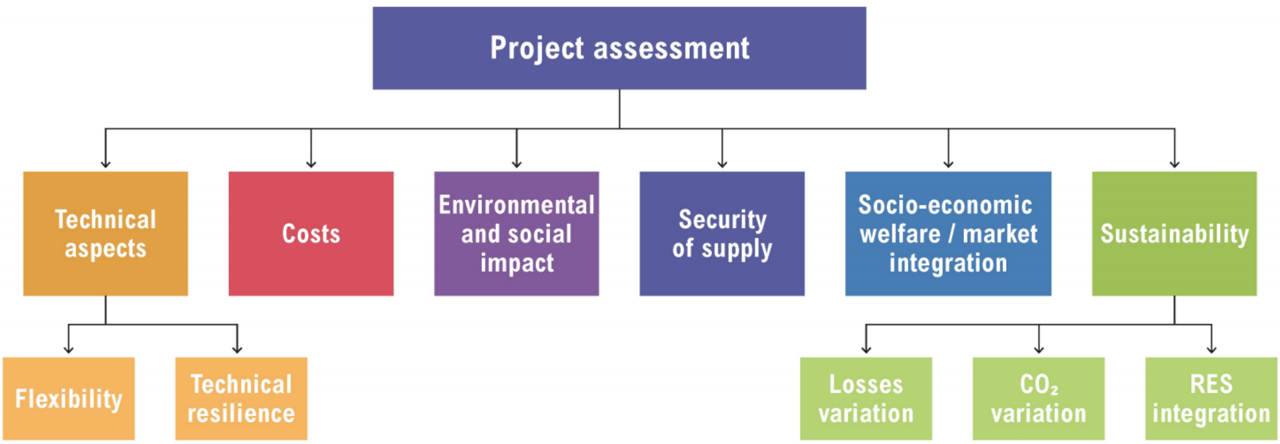

Figure 10.2. Utilization of TSO Data by NRA Investment Plan

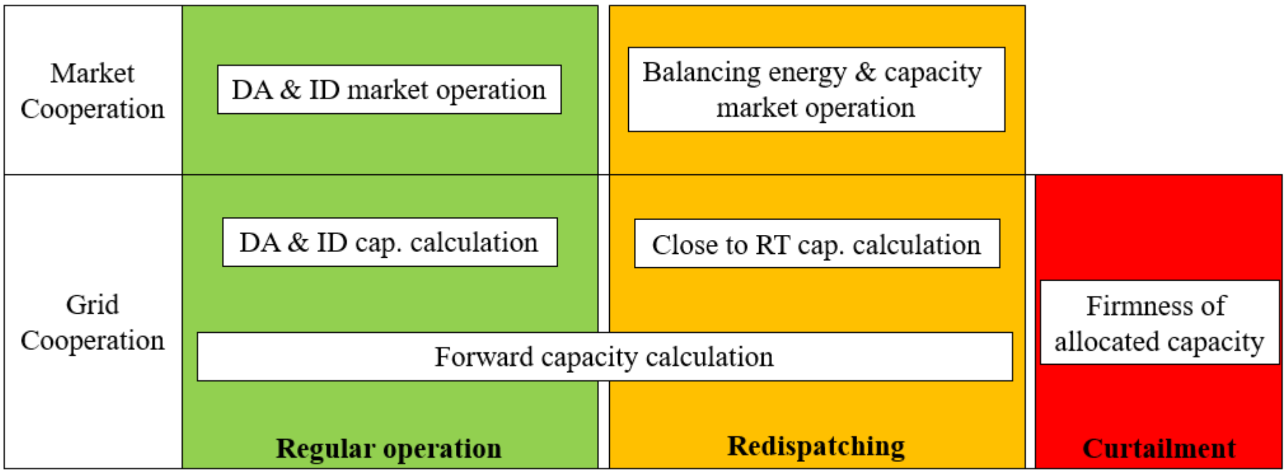

Figure 10.3. Utilization of TSO Data by NRA Inter-TSO Coordination

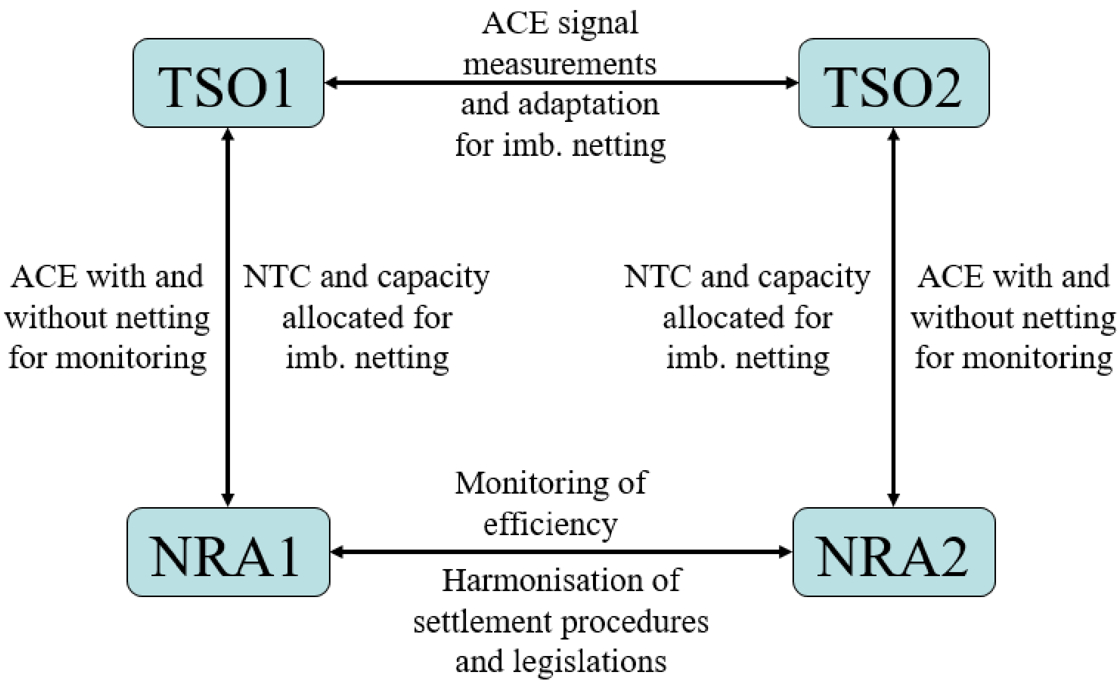

Figure 10.4. Imbalance Netting Harmonization Requirements