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FLEXIBILITY ASSESSMENT OF THE MOLDOVAN POWER SYSTEM: FINAL PROJECT REPORT

MOLDOVA ENERGY SECURITY ACTIVITY

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Submission Date: April 24, 2024

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ABBREVIATIONS

AC	Alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
BESS	Battery Energy Storage System
BOP	Balance of Plant
Bloomberg NEF	Bloomberg New Energy Finance
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
CE	Continetal Europe
CEA	Capacity Expansion Analysis
CESA	Continental Europe Synchronous Area
CHP	Combined Heat and Power
EENS	Expected Energy Not Served
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Engineering, Procurement, and Construction
ERAA	European Resource Adequacy Assessment
EU	European Union
FCR	Frequency Containment Reserve
FO	Forced Outage
FRR	Frequency Restoration Reserve
GJ	Gigajoule
ICE	Internal Combustion Engine
kV	Kilovolt
LFC	Load Frequency Control
LFP	Lithium-Iron-Phosphate
LLD	Loss of Load Duration
LOLE	Loss of Load Expectation
MAE	Mean Absolute Error
MESA	Moldova Energy Security Activity
MD	Moldova
mFRR	Manual Frequency Restoration Reserve
MJ	Megajoule
MVA	Megavolt-Ampere
MGRES	Moldavskaia GRES Power Plant
MW	Megawatt

NMS	Nickel-Manganese-Cobalt
NMAE	Normalized Mean Absolute Error
NMC	(Lithium-)Nickel-Manganese-Cobalt
NPV	Net Present Value
NTC	Net Transfer Capacity
OCGT	Open-Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operating Expenses
PCA	Production Cost Analysis
PCS	Power Conversion System
PV	Photovoltaic
RES	Renewable Energy Source
RO	Romania
RORP	Run-of-River Pondage
SAFA	Synchronous Area Framework
SCADA	Supervisory Control and Data Acquisition System
SCR	Short-Circuit Ratio
SOC	State of Charge
SOGL	System Operation Guideline
TJ	Terajoule
TSO	Transmission System Operator
UA	Ukraine
USAID	U.S. Agency for International Development
USD	U.S. Dollar
VRES	Variable Renewable Energy Source

EXECUTIVE SUMMARY

Moldova's power system demonstrates a reduced ability to handle fluctuations between production and consumption due to the country's inflexible generation sources, such as combined heat and power plants (CHPs) and Soviet-era power plants, which have limited load-following capabilities. This puts the operational stability of the system at risk and threatens the continuity of electricity supply. At present, Moldova lacks the operating reserves required to meet European Network of Transmission System Operators for Electricity (ENTSO-E) standards for load frequency control (LFC) and other ancillary services necessary for a transmission system operator (TSO) in the Continental Europe Synchronous Area (CESA).

To help resolve this problem, the U.S. Agency for International Development (USAID) through its Moldova Energy Security Activity (MESA), assessed the current electricity balancing and LFC structure and requirements in Moldova's power system as well as those anticipated with the accelerated penetration of renewable energy sources (RES) utilizing specific development scenarios that the Government of Moldova is considering, that include 2025 and 2030 targets. This study analyzes frequency containment reserve (FCR) and frequency restoration reserve (FRR) requirements and identifies the appropriate size and location of various technology assets required to meet the system's present and future reserve needs.

A wide spectrum of 12 scenarios were analyzed, mapping the evolution of the system in the two target years—2025 and 2030. The scenarios address three possible pathways for RES deployment in Moldova as well as the availability of MGRES to supply the right bank of the Nistru River. An assessment of concrete technical solutions to meet reserve needs was performed based on a holistic analysis of the system impacts.

For the dimensioning of FRR, a detailed probabilistic assessment was performed in line with European regulations (Regulation 2017/1485 establishing a guideline on electricity transmission system operation [SOGL] and Synchronous Area Framework [SAFA] recommendations) using a state-of-the-art approach and the principles applied within the Elia Group TSOs and ENTSO-E. A detailed zonal model was developed for 2025 and 2030 containing the projected evolution in load and generation for Moldova (left and right banks), Romania, and Ukraine. The impact of electricity flows between neighboring countries and the rest of Europe was modeled via net transfer capacities (NTC), considering all other detailed techno-economic constraints. The results of this step are the overall generation, load, and area exchanges for all the scenarios. The analysis was performed using PLEXOS energy modeling software. To determine scenarios with inadequate generation capacity, probabilistic Monte-Carlo–based adequacy assessment was performed. Using multiple load and RES time series along with generator forced outages, the reliability metrics of loss of load expectation (LOLE) and expected energy not served (EENS) were calculated. A LOLE threshold of 15 hours per year was determined to be suitable for Moldova.

A comprehensive screening was undertaken, involving a thorough examination of local and international design standards, operational standards, CESA, and other European network codes to identify the most appropriate assets to fulfill the identified reserve requirements in terms of the asset technology, capacity, and the optimal location to maximize system support.

The assessment of balancing reserve requirements for Moldova shows that the amount of required FCR is expected to remain 5 MW, as per the current agreement with Ukraine. The total estimated cost of a 5 MW/5 MWh battery energy storage system (BESS) is $8,779,630.

According to the assessment of FRR needs, Moldova needs about 240 MW of FRR to cover 99 percent of imbalances in 2025 and 2030. From this capacity, increased automatic frequency restoration reserve (aFRR) requirements of 60–72 MW are projected, corresponding to higher RES penetration in 2030. This capacity should consist of fast-ramping assets to cover fast variations in imbalances. Accordingly, manual frequency restoration reserves (mFRR) requirements are estimated in the range of 163–174 MW.

For aFRR, the BESS/internal combustion engines (ICE) combinations were assessed through a detailed financial model, mapping the key net present value (NPV) indicators. The configuration of two hours of BESS and four ICE units is considered optimal, as it offers the lowest NPV and aligns with current industry practices. This configuration balances the higher initial capital expenditure (CAPEX) with reduced operational expenses over time, considering both immediate and future financial commitments. Total estimated cost for aFRR provision is $151,639,840, corresponding to the costs of a 72 MW/144 MWh (two-hour) BESS at $74,800,000 and four 72 MW ICE units at $76,839,840.

Considering the required capacity to meet mFRR requirements, a total installed capacity of 172 MW is necessary. Based on the findings of the market analysis, to meet mFRR requirements (172 MW), ten ICE units should be deployed, resulting in a total installed capacity of 180 MW. Furthermore, it is considered a best practice to incorporate a backup unit to ensure uninterrupted availability during maintenance periods. This requires a total capacity of 198 MW from 11 units. The total cost for ICEs with 198 MW capacity is estimated at $211,309,560.

Therefore, the total estimated cost of the combined proposed solution is $371,729,030.

Under the conditions of the critical scenario, the analysis shows no relevant violations in loading or voltage in the N-1 situation when ICE and BESS assets are introduced in the suggested locations. In principle, Straseni can properly accommodate the installation of the intended BESS, whereas Balti, Orhei, and Floresti can host the ICEs.

1 INTRODUCTION

1.1 BACKGROUND

Moldova's power system demonstrates a reduced ability to handle fluctuations between production and consumption due to the country's inflexible generation sources, such as CHPs and Soviet-era power plants, which have limited load-following capabilities. This puts the operational stability of the system at risk and threatens the continuity of electricity supply. At present, Moldova lacks the operating reserves required to meet ENTSO-E standards for LFC and other ancillary services necessary for a TSO in the CESA. This shortage of operating reserves leads to system imbalances and represents an uncontrolled, financially costly risk for all market participants, including potential RES investors. Addressing this issue is expected to significantly increase security of supply, decrease the financial risks for the local TSO, Moldelectrica, and remove a significant barrier to RES investments and support the acceleration of the energy transition.

1.2 PROJECT OBJECTIVE AND SCOPE

The project's objective is to assess the current electricity balancing and LFC structure and requirements in Moldova's power system as well as those anticipated with the accelerated RES penetration in specific development scenarios that the Government of Moldova is considering for the next years. This analysis assesses FCR and FRR requirements and identifies the appropriate size and location of various technology assets required to meet the system's present and future reserve needs. The result of the analysis provides a techno-economic assessment of the proposed assets.

1.3 PROJECT REPORT STRUCTURE

The project is structured across six activities, as shown in the figure below. The inception report (Activity 1) was delivered separately and included a preliminary analysis, data collection, and agreement on analysis scenarios. This report presents the results of Activities 2, 3, and 5 (cost estimates). Results from Activities 4, 5, and 6 related to the tendering and procurement of the assets will be provided separately as dedicated deliverables (technical documents).

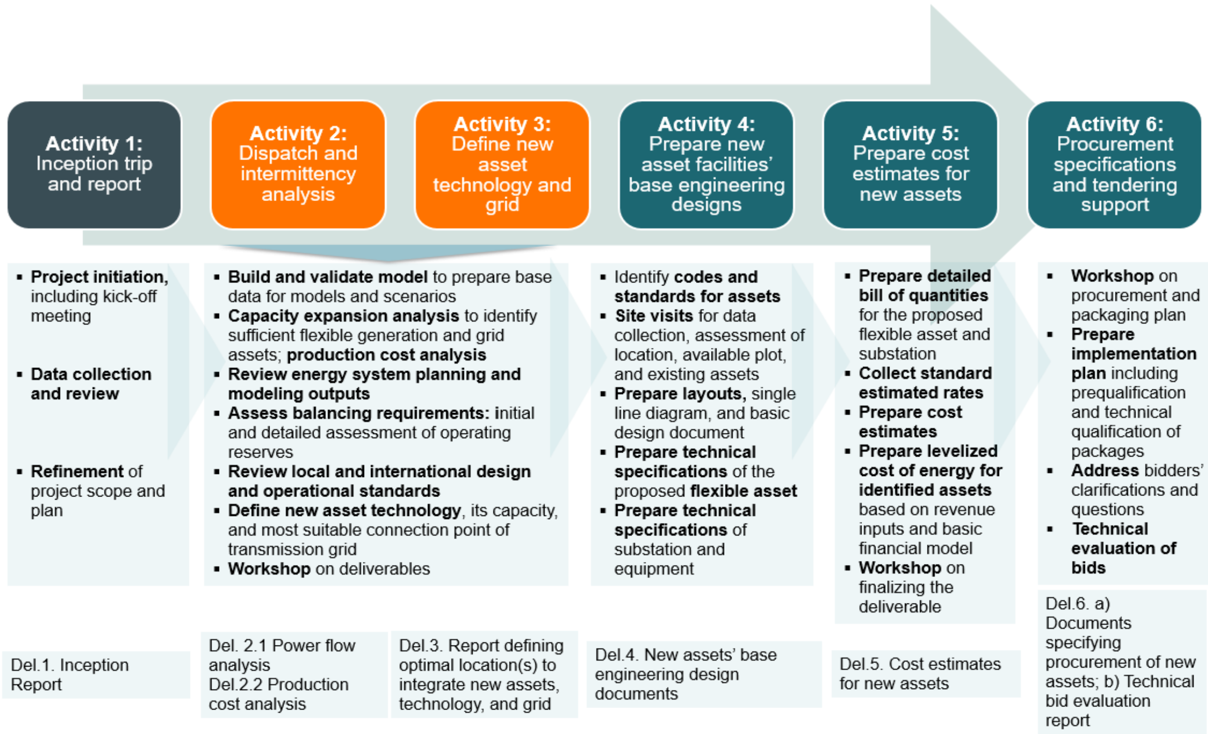

Figure 1 Overview of the project scope.

This report is structured in eight chapters:

- Chapter 1 (Introduction) highlights the background and project objectives.
- Chapter 2 presents the scenario framework for the analysis in terms of expected evolution of the generation system, load, and sensitivities.
- Chapter 3 presents the balancing reserve requirements for Moldova based on a probabilistic reserve dimensioning approach.
- Chapter 4 presents the results of the regional dispatch analysis to estimate system production cost and generation dispatch. The analysis includes a probabilistic adequacy assessment to filter out possible scenarios with inadequate results.
- Chapter 5 presents the assessment of the optimal technology for the proposed assets.
- Chapter 6 presents the techno-economic assessment to determine the technology and optimal sizing of the proposed assets to fulfill Moldova's flexibility needs.
- Chapter 7 presents an assessment of the most suitable connection points to Moldova's transmission grid for the new assets.
- Chapter 8 estimates the total cost of the new assets.
- Chapter 9 provides the key conclusions and recommendations of the study.

2 SCENARIO FRAMEWORK

Scenario development started with by establishing the baseline, for which the team used the macroeconomic projections and key parameters identified in MESA's Storyline Report for the development of Moldova's electricity and gas transmission networks[1]. Given the scope of the study, multiple scenarios were considered to provide a solid foundation for assessing the future flexibility needs of Moldova's power system. In total, 12 scenarios were analyzed covering three main aspects of future development. The scenarios address all combinations of 1) two target years, 2) three levels of RES penetration, and 3) the availability of MGRES generation to cover electricity demand on the right bank of the Nistru River. MGRES's availability is indicated in the scenario name by "w" (with, indicating that MGRES is fully available) or "wo" (without, indicating that MGRES is not fully available). The scenarios were developed in close collaboration with Moldelectrica during the inception visit to Chisinau on September 11, 2023.

1. **Target years:** The study focused on two target years—2025 and 2030, with changes in generation, load, and interconnection capacities. The year 2025 was selected because it represents the earliest possible deployment of the assets. And the year 2030 was selected because the majority of Renewable Energy Sources (RES) projects are anticipating completion by then.
2. **RES penetration:** For each target year, three scenarios were developed for RES penetration: Base, Slow, and Fast. These scenarios project an overall increase in RES capacities from 2025 to 2030. The *Base Scenario* considers the existing RES installed capacities and the defined targets for RES generation for the target years. These targets are based on the Government's draft National Energy and Climate Plan and the draft 2050 Energy Strategy. The *Slow and Fast Scenarios* are used to assess the sensitivity of the results and impact of the variable RES generation on the flexibility needs. In comparison to the *Base Scenario*, the *Slow Scenario* shows an increase of 100 MW in Photovoltaic (PV) capacity, and a 20% decrease in wind capacity. In the *Fast Scenario*, there is a 200 MW increase in PV capacity compared to the *Base Scenario*, and the installed capacity of wind is 20% higher than expected in the *Base Scenario*. The 20% increase/decrease in wind capacity in the *Fast/Slow Scenarios* was factored to provide a sensitivity analysis for the scenarios. Other generation capacities, including bio sources (biomass, biogas, waste and others), are held constant in all variations.
3. **MGRES availability:** The third dimension is a sensitivity applied to the above six scenarios regarding the availability of MGRES for the right bank.

Figure 2 shows the outlined RES scenarios, while Table 1 shows the installed generation capacity in the Moldovan power system for each scenario.

Moldovan historical load data for the year 2022 were used as the basis and projected for future years, assuming an annual load growth factor of 1.7 percent (as agreed with Moldelectrica), sufficient to sustain annual GDP growth of close to 5 percent.

[1] THE STORYLINE REPORT FOR DEVELOPMENT OF MOLDOVA'S ELECTRICAL AND GAS TRANSMISSION NETWORKS, OCTOBER 24, 23 – USAID MESA

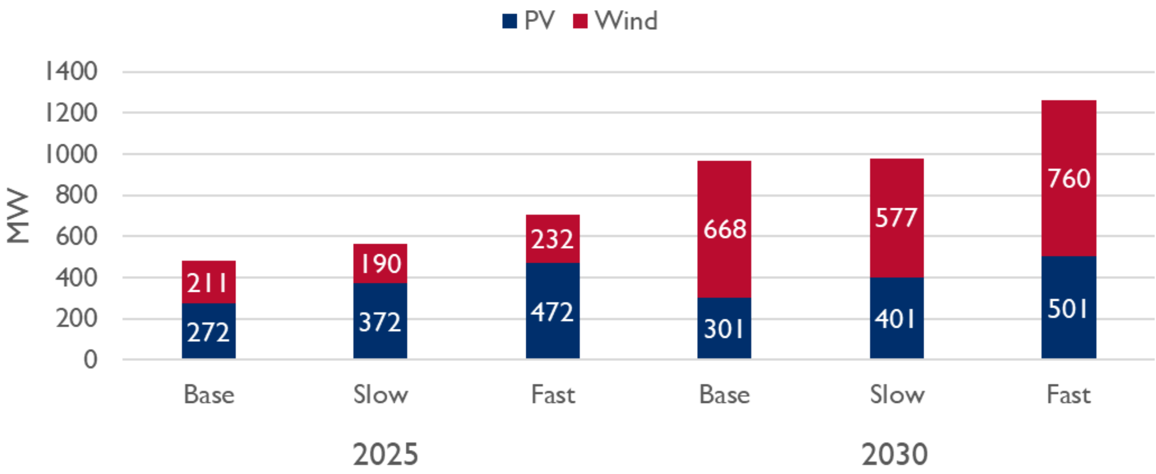

Figure 2 Analyzed scenarios: three RES scenarios for two target years with sensitivity for MGRES availability

Table 1 List of generation units in the Moldovan system for the scenarios analyzed

Region	Power plant	Units	Installed capacity [MW]	Units	Installed capacity [MW]
	Year	**2025**		**2030**	
MD Left Bank	MGRES_10	1	210	1	210
	MGRES_11	1	250	1	250
	MGRES_12	1	250	1	250
	MGRES_4	1	200	1	200
	MGRES_5	1	200	1	200
	MGRES_7	1	200	1	200
	MGRES_8	1	200	1	200
	MGRES_9	1	210	1	210
	Dubasari_RORP	1	48	1	48
MD Right Bank	CHP North 1	1	12	1	12
	CHP North 2	1	12	1	12
	CHP North 3	1	3.35	1	3.35
	CHP North 4	1	3.35	1	3.35
	CHP North 5	1	3.35	1	3.35
	CHP North 6	1	3.35	1	3.35
	Bio	-	-	2	75
	Termoelectrica CET_1	2	22	2	22
	Termoelectrica CET_2	3	196	8	170
	Costesti_RORP	1	16	1	16
	West_CHP (Chisinau)	3	33	3	33

3 DEFINITION OF SYSTEM BALANCING REQUIREMENTS

This chapter corresponds to Activity 3.2 of the inception report. It presents the dimensioning of the necessary operating reserve levels (FCR and FRR) for the reliable and secure operation of the system, considering the overall generation mix and the future RES penetration levels in each scenario.

Operating reserves are made up of frequency containment reserves (FCR) and frequency restoration reserves (FRR), the latter of which is further split into automatic FRR (aFRR) and manual FRR (mFRR).[2] As per the current Operational Agreement forming the Ukraine–Moldova LFC block, Moldova is required to keep 5 MW of reserves for FCR and ±34 MW for aFRR, dimensioned based on the deterministic methodology for reserve dimensioning. However, these requirements do not consider the future developments in RES, load, and other energy efficiency technologies. Therefore, for future scenarios, it is necessary to define a new level of operating reserves.

3.1 DIMENSIONING OF FCR REQUIREMENTS

FCR is dimensioned at the level of the synchronous area. The reserve capacity for FCR required by European regulations for CESA is set considering the dimensioning incident (biggest incident in the synchronous area), equal to 3,000 MW. This volume is distributed among the continental European TSOs proportional to their system sizes. Based on the Ukraine–Moldova draft control block agreement, the required level of FCR for Moldova's power system is maintained at the current value of 5 MW.[3]

3.2 DIMENSIONING OF FRR REQUIREMENTS

For the dimensioning of FRR, a detailed probabilistic assessment was performed in line with European regulations (SOGL[4] and SAFA[5] recommendations), using a state-of-the-art approach and the principles applied within the Elia Group TSOs and ENTSO-E. The input data and the methodology used for this dimensioning are detailed in the following sections.

3.2.1 INPUT DATA: SOURCES OF SYSTEM IMBALANCES

A probabilistic approach combines information on all possible sources of system imbalances, namely based on combination events caused by 1) system imbalances (based on historical records for 2022), 2) forced outages of generators, and 3) RES and load forecast errors. The approach is presented below.

3.2.1.1 HISTORICAL SYSTEM IMBALANCES

Historical imbalances are used to estimate the baseline imbalances of the system, mapping the general imbalance "behavior." Typically, historical imbalances are used in high frequency to enable a close representation of the impacts on system operation. To obtain baseline imbalances, a filtering process is applied to historical measurements in order to exclude imbalances due to forced outages of conventional generating units, as those are added separately for the future system in a later step.

Moldelectrica provided historical imbalance time series data for 2022, corresponding to the difference between net scheduled imports and net physical imports. The original imbalance time series is shown Figure 3Figure 3 and covers a range between +700 MW and -1,000 MW. The measurements include imbalances due to historical forced outage events, system blackout, and instances with possible

[2] Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation, Article 153

[2] EU4Energy Governance – Supporting Ukraine and Moldova with Post-Synchronization Processes Related To ITC Mechanism, Settlement of Unintentional Deviations within Block and Capacity, Appendix 1.

[4] Commission Regulation (EU) 2017/1485.

[5] SAFA, Annex 1, Paragraph B-6-2-2-1-5.

measurement errors, which were filtered out. After cleaning, the imbalances present reduced deviations on a range between +204 MW and −199 MW, as shown in Figure 4

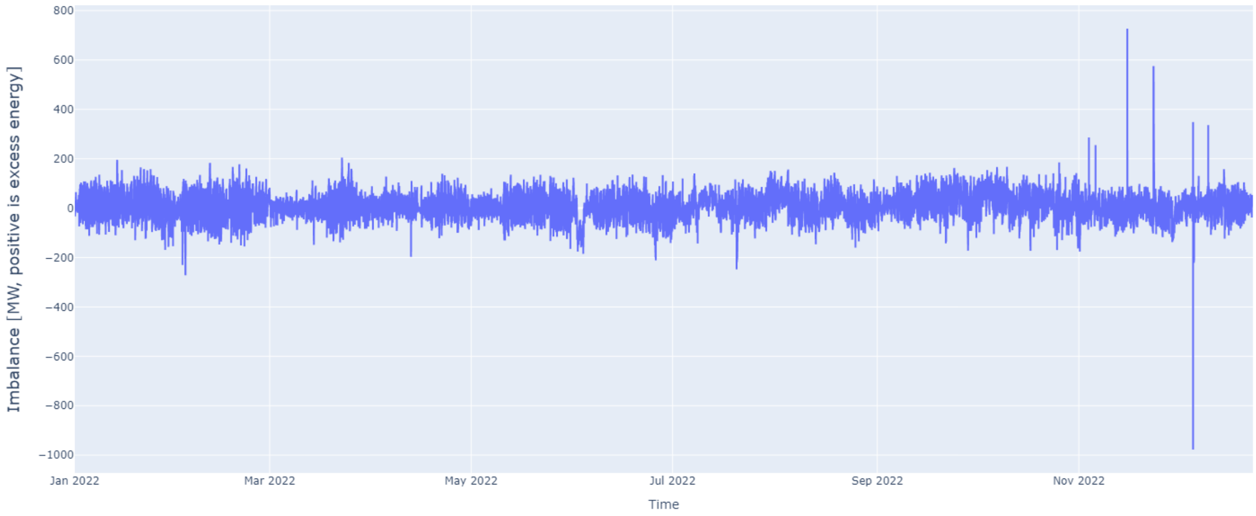

Figure 3 Original historical imbalance time series for Moldova, 2022

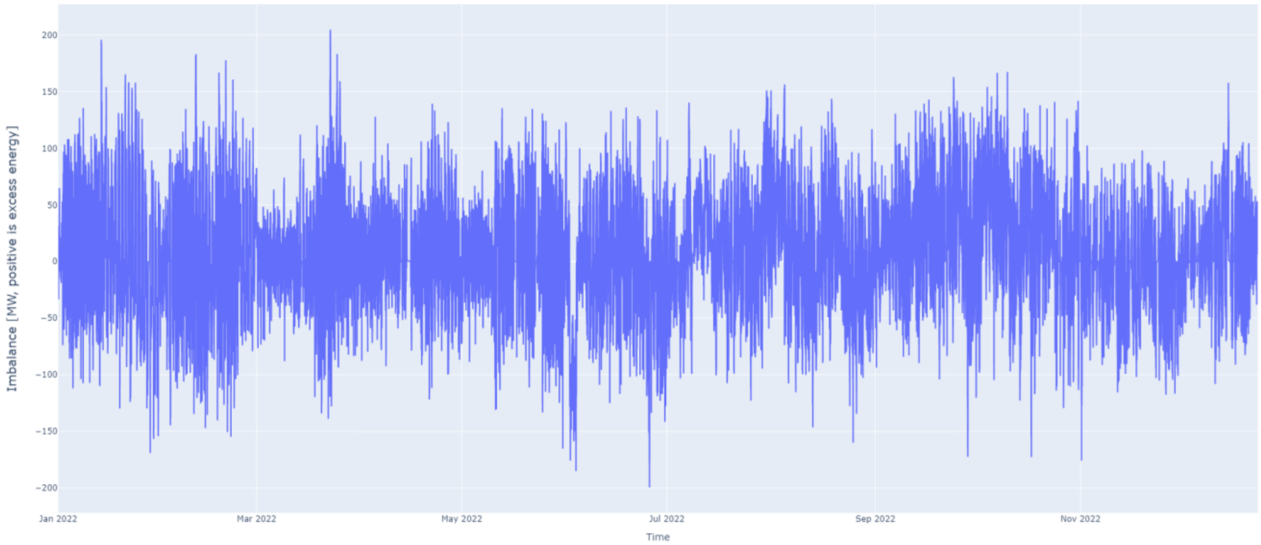

Figure 4 Historical imbalance time series for Moldova, 2022, after cleaning forced outages and measurement errors

3.2.1.2 IMBALANCES FROM FUTURE POSSIBLE FORCED OUTAGES OF CONVENTIONAL UNITS

Installed generation capacity is an important input for the analysis, as it determines the impact of future forced outages. It includes MGRES units for all scenarios, with the largest unit being 250 MW. The number of MGRES units considered in the analysis drastically affects the possible imbalances due to forced outages. Therefore, initially all MGRES units are considered in the reserve sizing.

Forced outages on the unit level are considered for all conventional generation units per target year. For each target year, multiple hourly time series samples are generated to simulate the forced outages of the conventional generation units. For these simulations, the forced outage (FO) rates were extracted from the European Resource Adequacy Assessment (ERAA) 2022 report from ENTSO-E, using Romanian units as a proxy for the Moldovan generators. The forced outage rates used are shown in Table 2.

Table 2 Forced outage rates used in forced outage calculation

Region	Power Plant	Forced Outage Rate [%]
MD Left Bank	MGRES	4.877
	Dubasari_RORP	5
MD Right Bank	Balti	4.877
	Bio	4.877
	Termoelectrica	4.877
	Costesti_RORP	5
	West_CHP (Chisinau)	4.877

Figure 6 shows an example of the distribution of imbalances due to forced outages for the Base scenario in 2025 in the top right corner. The figure only shows negative imbalances because units coming into operation are scheduled and therefore do not create any imbalances. The maximum values of forced outages are around −600 MW when all MGRES units are considered.

3.2.1.3 FUTURE RES AND LOAD FORECAST ERROR

The imbalances due to future RES and load forecast error were modeled using a random error time series generator. The errors, or "noise," were simulated separately for load, PV, and wind based on a Laplace distribution for two error scenarios to obtain two error time series for each RES and load. The model uses the mean absolute error (MAE) and the autocorrelation coefficient as input parameters. The MAE represents the average range of errors (standard deviation), and the autocorrelation coefficient defines the correlation in time between two consecutive values.

The MAE and autocorrelation coefficient values used for RES and load are shown in Table 3**Error! Reference source not found.**. These values were estimated using two years of data on forecast errors at the TSO Elia in Belgium. The MAE values considered are at system level and are lower than the expected values at the level of a single RES power plant. Literature reports MAE values of approximately 5 percent for wind farms and 2 percent for PV plants.

Table 3 MAE and autocorrelation coefficient used for RES and load

	PV	Wind	Load
MAE	1.5%	2.6%	2%
Autocorrelation coefficient	0.568	0.566	0.5

The error time series were then multiplied with the production time series of RES and the load time series to create the corresponding imbalance time series. Production time series for PV and wind were generated using the U.S. National Renewable Energy Laboratory (NREL) system advisor model tool, which creates hourly per-unit values based on standard PV and wind parameters.[6] This per-unit time series was then scaled to future RES capacities for Moldova. Similarly, historical load data records were used to estimate the load, which was then scaled to future increases and then combined with the load forecast errors to create the load imbalance time series.

An example of the distribution of imbalances due to PV, wind, or load forecast errors for the Base 2025 scenario is shown in the bottom-left corner of Figure 6.

[6] NREL, System Advisor Model, https://sam.nrel.gov/

3.2.2 APPROACH: MAPPING THE TOTAL SYSTEM IMBALANCES

3.2.2.1 SIZING THE FREQUENCY RESTORATION RESERVES

The dimensioning of FRR was performed using a probabilistic assessment based on international best practices at Elia and ENTSO-E. For this purpose, a Python tool was developed. For systems with variable RES, the probabilistic dimensioning approach shows better results than deterministic approaches. All TSOs within ENTSO-E are required to follow a probabilistic approach for dimensioning of FRR.[7]

An overview of the probabilistic FRR dimensioning methodology is presented in Figure 5. This type of analysis is based on mapping the expected operational uncertainty using historical time series and other expected low-probability events such as forced outages, forecast errors, and weather extremities. Different imbalance scenarios are simulated by applying the Monte Carlo method, which samples imbalance sources and creates 20 years of 15-minute imbalance data scenarios. The 99th percentile is used to estimate the FRR size from the total imbalance.

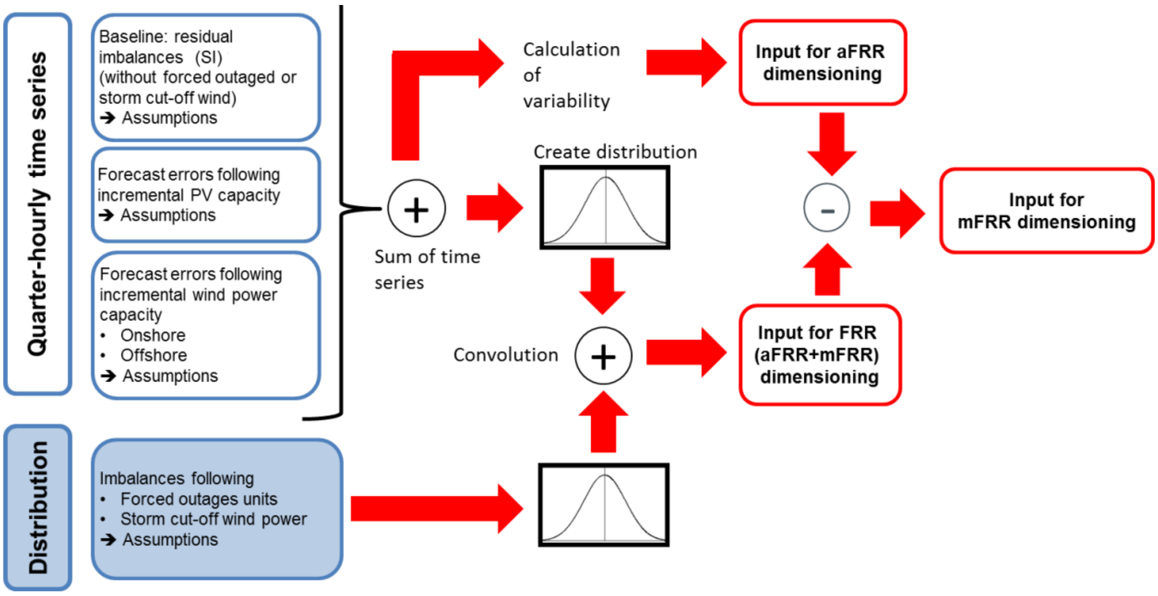

Figure 5 Overview of probabilistic FRR dimensioning methodology[8]

For illustration purposes, the probability distribution of the total simulated imbalances is displayed for the Base 2025 scenario in Figure 6. The figure also displays how the total imbalances are formed by the historical imbalances, imbalances due to PV, wind or load forecast errors, and imbalances due to forced outages. The top-left corner in Figure 6 shows an example of the historical imbalances for the Base 2025 scenario. The large spike around the zero value indicates that a large number of historical imbalance values are zero. The probability distribution for the total imbalances for the Base 2025 scenario shows that the total imbalances are skewed toward negative values due to the inclusion of forced outages.

[7] Commission Regulation (EU) 2017/1485, Article 157(2)(H) And (I).
8 Elia Group internal methodology.

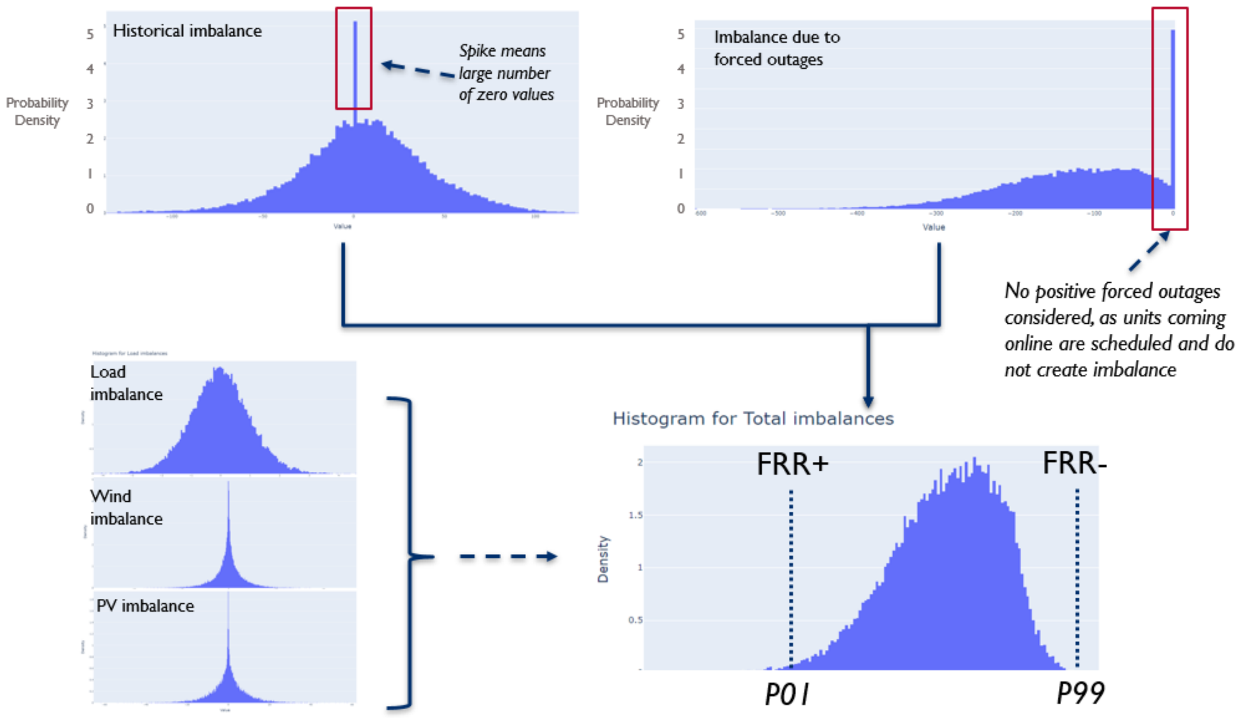

Figure 6 Probability distributions of historical imbalances (top left), forecast errors (bottom left), forced outages (top right), and total imbalances (bottom right) in the Base 2025 scenario

3.2.2.2 DIMENSIONING THE AUTOMATED FREQUENCY RESTORATION RESERVES

The aim of aFRR is to respond to imbalances that are too fast for other generating units to resolve. The TSOs of continental Europe have jointly recommended to size aFRR based on the variability of 1-minute and 15-minute average imbalances.[9] Therefore, the volatility of historical imbalances is assessed by taking the difference between the 1-minute average historical imbalance and the 15-minute average historical imbalance. The 99th percentile of the resulting distribution is used to calculate the aFRR needs. Imbalances from forced outages are not included in the aFRR sizing assessment.

The additional variability of the imbalance values due to newly installed PV and wind capacities needs to be assessed as well. The effect of the new PV and wind capacities on imbalance variability is assessed based on the intra-quarter-hour variability of PV and wind energy production, estimating the distribution of the differences between 1-minute and 15-minute average production levels. It is assumed that these differences come from a Gaussian distribution, and the mean and standard deviation values are estimated based on historical data.

Because of the lack of conclusive historical data for Moldova, this assessment of variability from PV and wind (RES forecast error) was based on historical records from Belgium. First, the time series data were scaled to the installed capacities of PV and wind in the applicable scenario of the future Moldovan system. Next, average production was calculated for every 15 minutes. For each minute, the delta between the 1-minute production value and the 15-minute average was computed. From all these deltas, a probability distribution curve was established.

Finally, the historical imbalances and estimated PV, wind, and load forecast errors were combined. From the distribution obtained, the 99th percentile of the positive imbalances was used as the value for

[9] SAFA Paragraph B-6-2-2-1-5 recommends "that the positive aFRR is larger than the 1st percentile of the difference of the 1-minute average open loop area control error (ACEOL) and the 15 minute average ACEOL of the LFC block of the corresponding quarter of hour" (and vice versa for negative aFRR).

downward aFRR, and the 99th percentile for negative imbalances was used as the value for upward aFRR.

3.2.2.3 MANUAL FREQUENCY RESTORATION RESERVES

The mFRR was set at the difference between the FRR requirement and the aFRR requirement, namely:

$$mFRR = FRR - aFRR$$

3.2.3 RESULTS ON FUTURE RESERVE REQUIREMENTS

This section presents the results of the FRR requirement calculations. The plus sign (+) with the reserve type indicates the upward reserves needed to counter the negative imbalance and replace the lack of energy in the system. The negative sign (−) indicates the downward reserves needed to counter the positive imbalance and thus remove the excess energy from the system. The results are presented for a varying number of MGRES units considered in the forced outage calculation, with the final results presented at the end.

3.2.3.1 REQUIRED RESERVE SIZING WITH ONE MGRES UNIT

Initially, only one MGRES unit capped at 120 MW (as the largest unit in Moldova) was considered in the forced outage calculation. This assumption led to requirements of 61–73 MW of aFRR+ and 88–97 MW of mFRR+, as shown in Table 4.

Table 4 FRR requirements with one MGRES unit capped at 120 MW

		2025			2030		
	Unit	**Base**	**Slow**	**Fast**	**Base**	**Slow**	**Fast**
FRR+	MW	157	157	158	159	157	162
aFRR+	MW	61	65	70	62	67	73
mFRR+	MW	96	92	88	97	90	89
FRR−	MW	87	88	88	98	94	103
aFRR−	MW	51	57	66	54	59	67
mFRR−	MW	36	31	22	43	35	36

3.2.3.2 REQUIRED RESERVE SIZING WITH ALL MGRES UNITS

Later, it was agreed to include all MGRES units in the forced outage calculation and estimate the FRR requirements; this increased those requirements drastically, to more than 380 MW, as shown in Table 5. The impact is mainly on mFRR, as the system variability remains the same, mostly covered by aFRR.

Table 5 FRR requirements with all MGRES units

		2025			2030		
	Unit	**Base**	**Slow**	**Fast**	**Base**	**Slow**	**Fast**
FRR+	MW	386	385	386	389	386	391
aFRR+	MW	60	65	70	62	66	72
mFRR+	MW	326	320	316	327	320	319
FRR−	MW	96	96	96	106	105	111
aFRR−	MW	51	56	63	53	58	66
mFRR−	MW	45	40	33	53	47	45

This corresponds to a conservative scenario, as the forced outages were estimated assuming that all MGRES units are generating at the same time. A comparison of FRR sized for one and all MGRES units is shown in Figure 7. A large increase in mFRR+ can be seen in extreme scenarios with all MGRES units.

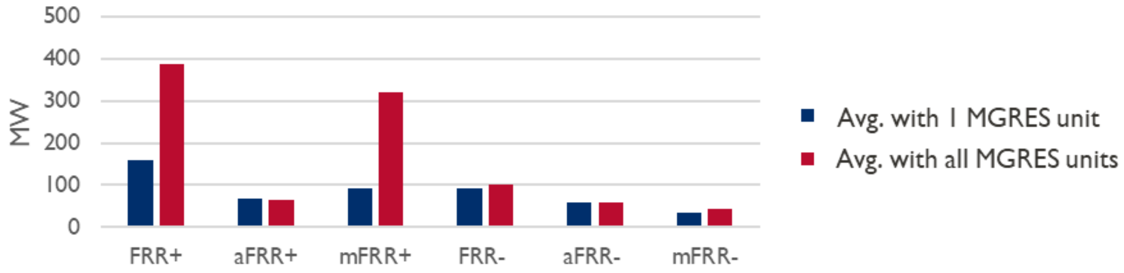

Figure 7 FRR requirements with one or all MGRES units

3.2.3.3 REQUIRED RESERVE SIZING WITH EXPECTED NUMBER OF MGRES UNITS IN NORMAL OPERATION

The initial dispatch simulations indicate that all MGRES units do not operate at the same time; rather, MGRES produces an average of 460 MW in 2025 and 250 MW in 2030, as shown in Figure 8. This is equivalent to the operation of three units in 2025 and two units in 2030 at rated capacity. Therefore, for the final estimations, the team considered a system based on the average number of operational MGRES units (two to four).

An analysis of the mFRR+ requirements for a reduced number of MGRES units results in the following sizes, also shown in Figure 8Figure 9:

- Two units of 200 MW each: 143 MW
- Three units of 200 MW each: 173 MW
- Four units of 200 MW each: 202 MW

Consequently, assuming all units are constantly in operation with a mFRR+ requirement of about 320 MW, if reserve is provided by an asset equal to the above capacities, the reliability criteria is reduced as follows:

- For 143 MW: 78 percent
- For 173 MW: 85 percent
- For 202 MW: 90 percent

Based on these calculations, it was concluded that the case of three units is a good basis for the dimensioning of reserves.

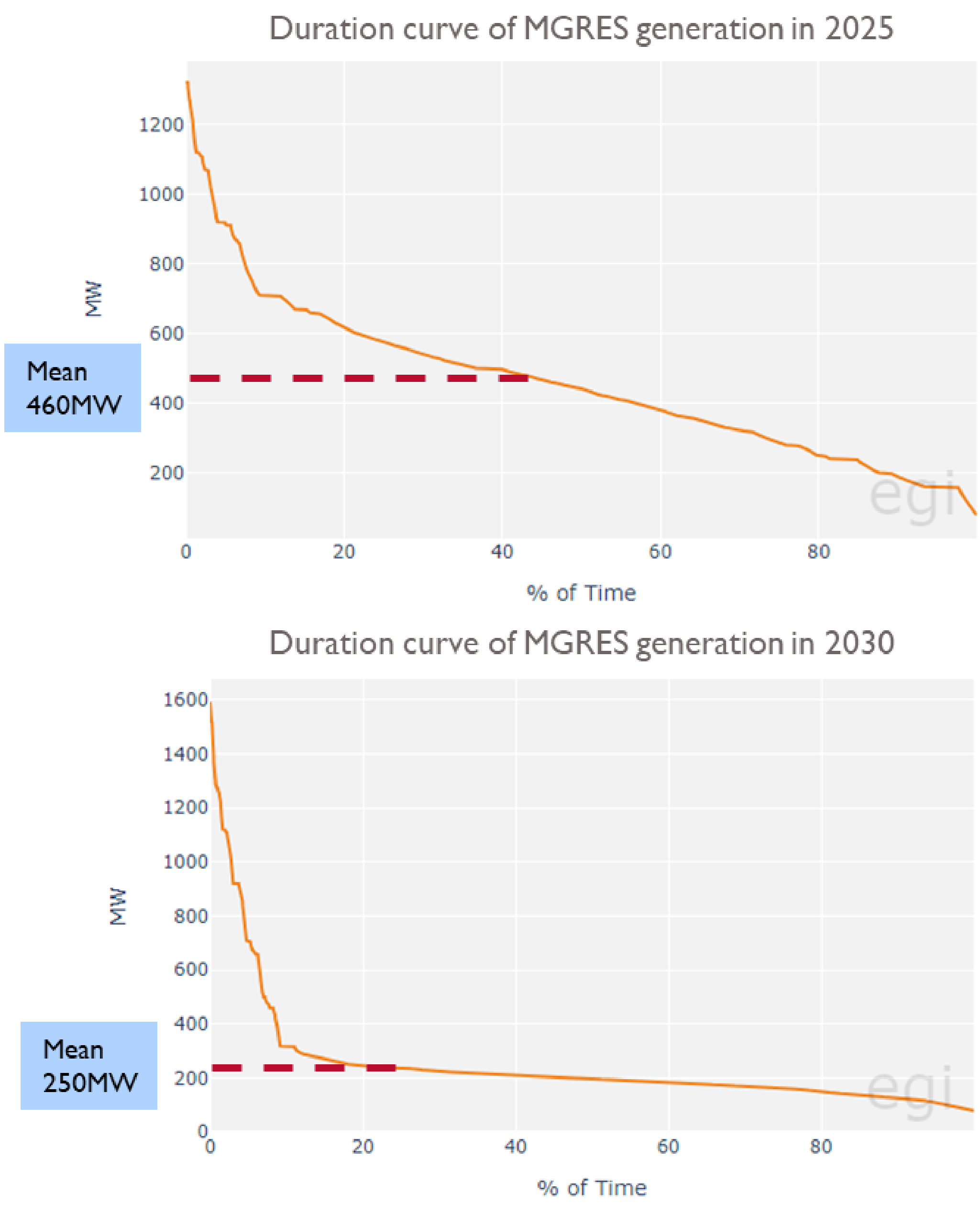

Figure 8 MGRES duration curves for 2025 and 2030 from dispatch simulations

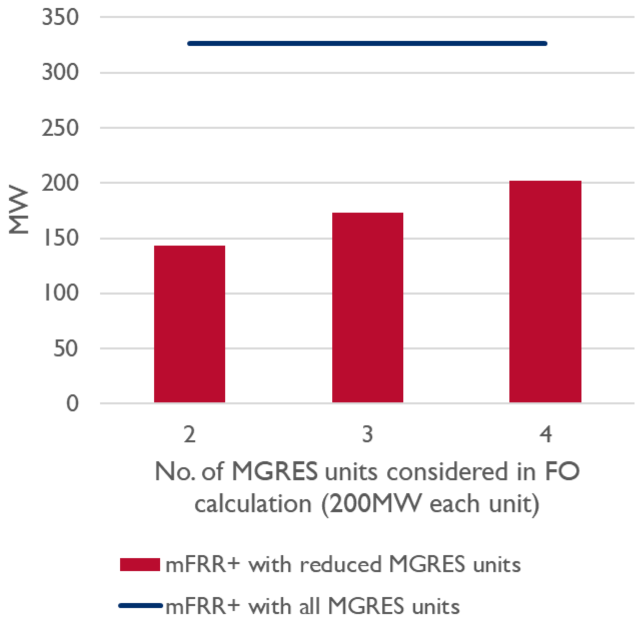

Figure 9 mFRR+ requirements for a reduced number of MGRES units

3.2.3.4 REQUIRED RESERVE SIZES FOR THREE MGRES UNITS

For the expected case with three MGRES units considered in forced outage calculations, the aFRR and mFRR requirements are presented in Table 6. The aFRR size remains the same, whereas the mFRR+ requirement is in the range of 163–174 MW, which is considered a good estimation of the system needs.

Table 6 FRR requirements with three MGRES units

		2025			2030		
	Unit	**Base**	**Slow**	**Fast**	**Base**	**Slow**	**Fast**
FRR+	MW	233	232	233	236	236	239
aFRR+	MW	60	65	70	62	66	72
mFRR+	MW	173	167	163	174	170	167
FRR-	MW	95	96	96	106	102	111
aFRR-	MW	51	56	63	53	58	66
mFRR-	MW	44	40	33	53	44	45

3.3 CONCLUSIONS

Moldova's operational reserve requirements for 2025 and 2030 were calculated based on a probabilistic assessment methodology that aligns with international best practices and the Elia Group approach:

- The amount of required FCR is retained at 5 MW as per the agreement with Ukraine. This value reflects the size of the Moldovan power system relative to the total CESA, multiplied by the continental European reference incident of 3,000 MW. Therefore, this value is fixed at the synchronous area level and cannot be influenced by Moldovan power system operations.
- About 240 MW of FRR will be required to cover 99 percent of imbalances in 2025 and 2030.

- MGRES drives the FRR+/mFRR+ requirements, which can be reduced by considering the expected number of units (three) in coincident operation.
- From 60 MW to 72 MW of the FRR should consist of fast-ramping assets (aFRR) to cover fast variations of imbalances. The increased values correspond to higher RES penetration in 2030.
- The mFRR+ requirement is in the range of 163–174 MW, which is considered a good estimation of the system needs.
- Whereas RES penetration and load growth induce the need for FRR, the decommissioning of large thermal units between 2025 and 2030 limits this effect toward 2030.

Under European Union (EU) network codes and guidelines, the actual sizing of reserves is done at the LFC block level (with Ukraine), as Moldova has the right to negotiate sharing of the reserve requirements as part of the LFC block agreement.

4 DISPATCH AND INTERMITTENCY ANALYSIS

This chapter corresponds to Activity 2 of the inception report, which deals with the capacity expansion analysis and production cost analysis based on the demand and generation forecasts for the future scenarios.

First, a detailed zonal model was prepared for 2025 and 2030 containing the development in load and generation for Moldova (left and right banks), Romania, and Ukraine.[10] The impact of electricity flows between neighboring countries and the rest of Europe was modeled via NTC, considering all other detailed techno-economic constraints. The result of this step was the overall generation, load, and area exchanges for all the scenarios. The analysis was performed using PLEXOS energy modeling software.

In the second step, a probabilistic Monte Carlo–based adequacy assessment was performed to determine scenarios with inadequate generation capacity. Using multiple load and RES time series along with generator forced outages, the reliability metrics of LOLE and EENS were calculated. A LOLE threshold of 15 hours per year was determined suitable for Moldova. The results indicate that all 2025 scenarios without MGRES's contribution for the right bank have higher LOLE than the threshold and are therefore inadequate.

A deeper dive into the simulation results can be found in Appendix 1.

4.1 PRODUCTION COST ANALYSIS

This section presents the results of the system production cost analysis, i.e., the generation dispatch for the scenarios that can be used in the nodal model for the grid analysis.

4.1.1 INPUT DATA

Extensive effort was invested in building and validating the necessary models for conducting the studies, involving several iterations for model calibration in close collaboration with Moldelectrica. The input data used to create the zonal model and perform the dispatch analysis are presented in the following subsections.

4.1.1.1 LOAD

Historical load data from Moldova for 2022 were used as the basis and projected for future years, assuming an annual load growth factor of 1.7 percent as agreed with Moldelectrica, sufficient to sustain annual GDP growth of close to 5 percent. The loads of Ukraine and Romania are based on data from ENTSO-E via the ERAA process.[11] Figure 10 shows the total load considered for the modeled countries for the target years of 2025 and 2030, where Ukraine has the largest load.

The peak loads of the load time series for each region are shown in Table 7,Table 7 Peak load of the time series used in the PLEXOS dispatch model (MW)Table 7 and the weekly load time series pattern is shown in Figure 11. The figure shows an increase in the load time series during winter months, which is most evident for Ukraine.

[10] PLEXOS energy modeling software (https://www.energyexemplar.com/plexos) was used for the analysis.
[11] European Resource Adequacy Assessment (ERAA) (entsoe.eu)

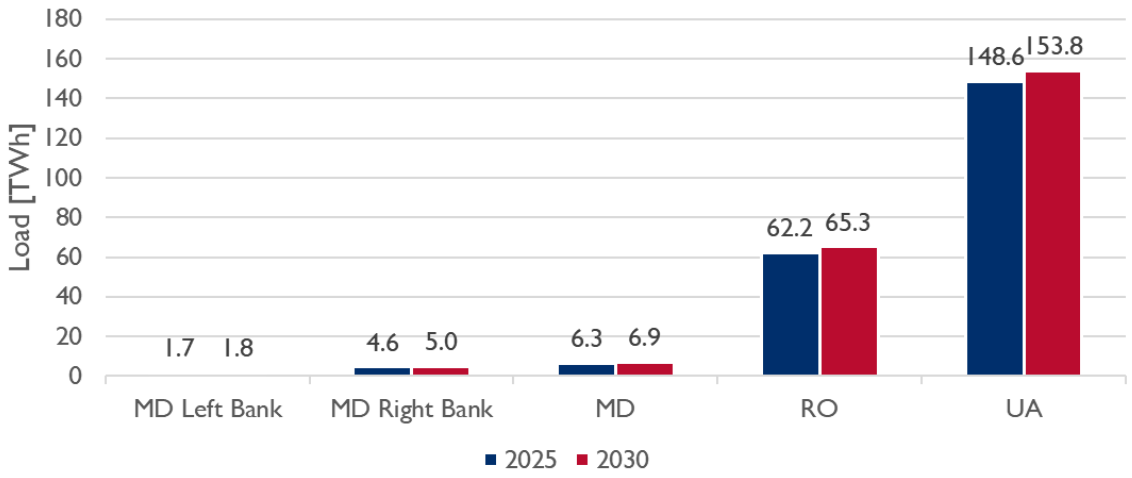

Figure 10 Total input load used in the model, 2025 and 2030

Table 7 Peak load of the time series used in the PLEXOS dispatch model (MW)

Target Year	MD Left Bank	MD Right Bank	Romania	Ukraine
2025	432	862	9,100	23,654
2030	470	936	9,634	25,562

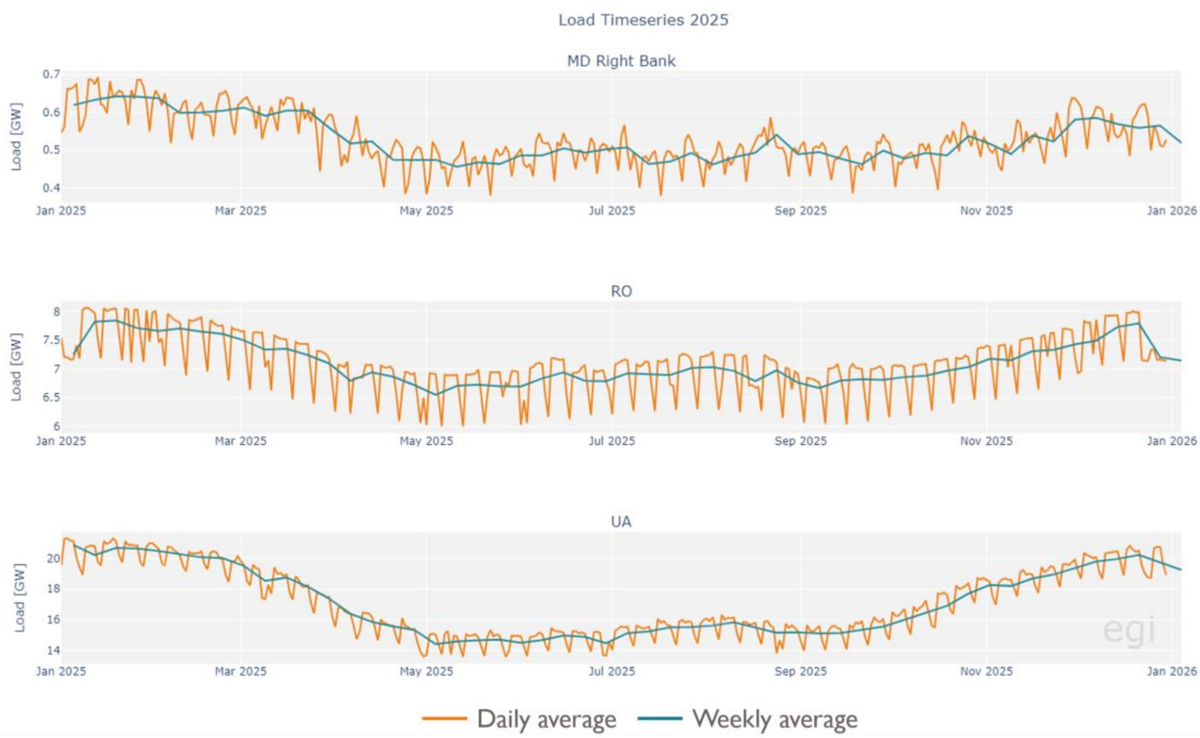

Figure 11 Weekly and daily load time series pattern for each zone, 2025

4.1.1.2 GENERATION CAPACITIES

The thermal generation in Moldova was modeled by unit level for both the Left and Right Banks. It remained constant for 2025 and 2030, except for biomass/biogas units (Bio) which is set to be introduced in 2030 and includes the new configuration for the Termoelectrica CET-2. Meanwhile, the capacities from RES were adjusted based on a different scenario. All the data points considered are shown in Table 8 with the changes across the years highlighted in bold.

Table 8 Thermal and RES generation capacities modeled for Moldova

Region	Scenario	Power Plant	Units	Installed Capacity [MW]	Units	Installed Capacity [MW]
		Year	2025		2030	
MD Left Bank	-	MGRES_10	1	210	1	210
		MGRES_11	1	250	1	250
		MGRES_12	1	250	1	250
		MGRES_4	1	200	1	200
		MGRES_5	1	200	1	200
		MGRES_7	1	200	1	200
		MGRES_8	1	200	1	200
		MGRES_9	1	210	1	210
		Dubasari_RORP	1	48	1	48
MD Right Bank	-	CHP North_1	1	12	1	12
		CHP North _2	1	12	1	12
		CHP North _3	1	3.35	1	3.35
		CHP North _4	1	3.35	1	3.35
		CHP North _5	1	3.35	1	3.35
		CHP North _6	1	3.35	1	3.35
		Bio	-	-	2	**75**
		Termoelectrica CET_1	2	22	2	22
		Termoelectrica CET_2	**2**	**196**	**8**	**170**
		Costesti_RORP	1	16	1	16
		West_CHP (Chisinau)	3	33	3	33
	RES Base	MD_PV	1	**272.4**	1	**301**
		MD_Wind	1	**211**	1	**668.6**
	RES Fast	MD_PV	1	**472.4**	1	**501**
		MD_Wind	1	**232**	1	**760.1**
	RES Slow	MD_PV	1	**372.4**	1	**401**
		MD_Wind	1	**190**	1	**577.1**

The generation capacities modeled for Romania were taken from ERAA 2022 and are shown in Figure 12Figure 12. Total generation for Romania is 20,575 MW and 25,150 MW for 2025 and 2030, respectively. The figure shows an increase in most generation types except lignite, which decreases in 2030.

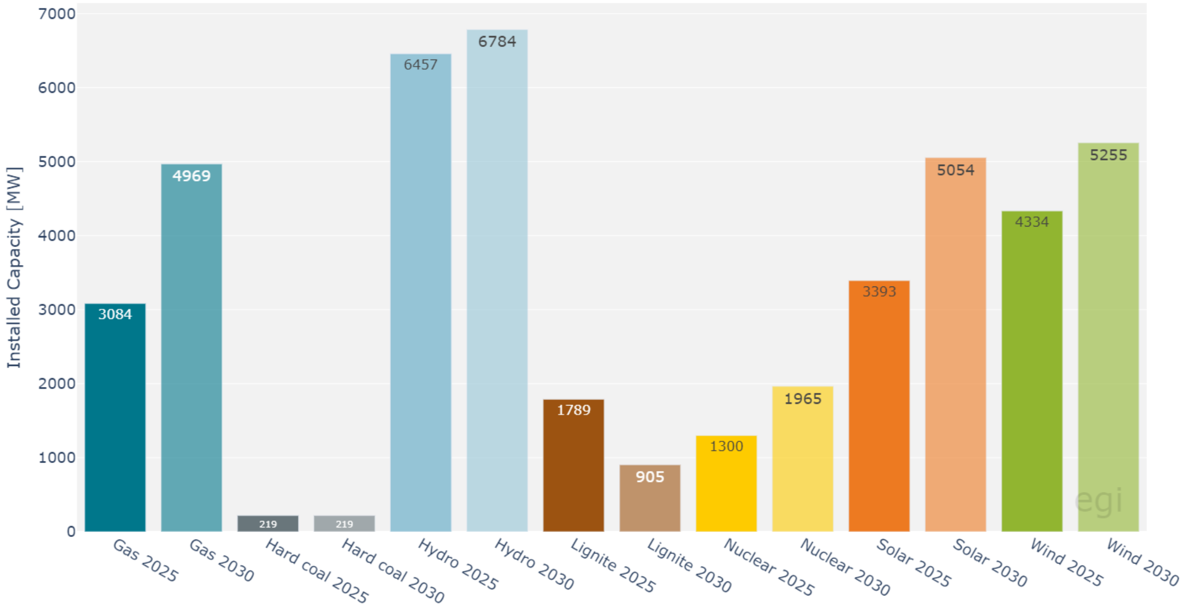

Figure 12 Total generation capacities modeled for Romania

Generation capacities for Ukraine are shown in Figure 13.Figure 13[12] The total generation for Ukraine is 37,476 MW and 39,493 MW for 2025 and 2030, respectively. The figure shows a major increase in PV and wind capacities.

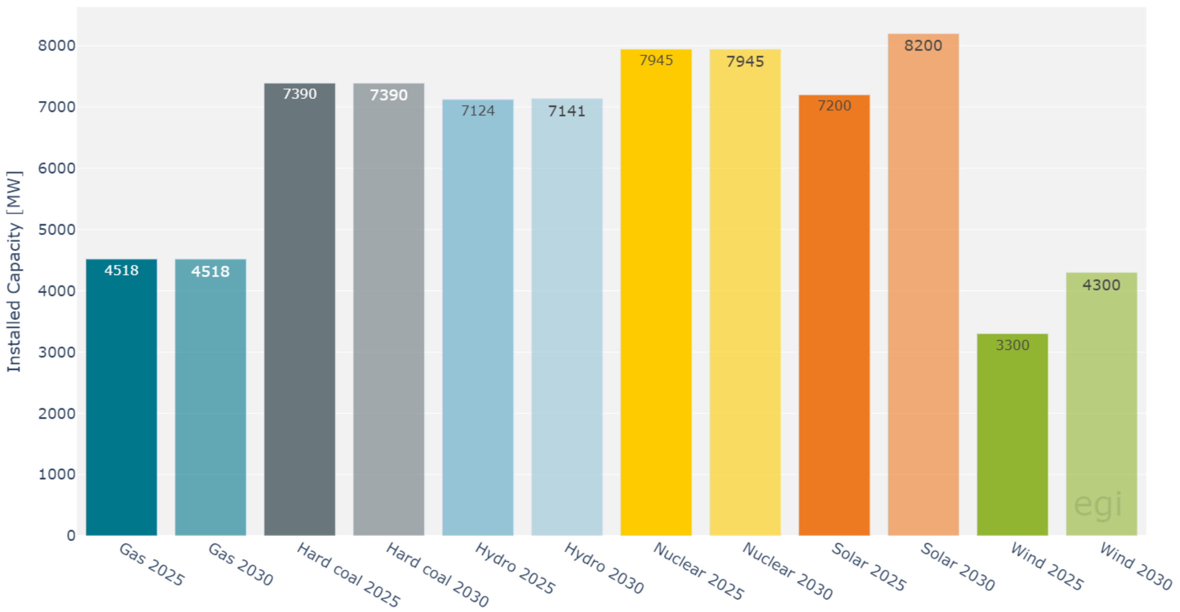

Figure 13 Total generation capacities modeled for Ukraine

4.1.1.3 FUEL PRICES

An important economic input parameter is the fuel price. For Ukraine and Romania, prices for different fuels were taken from ENTSO-E reports and are shown in Figure 14Figure 14.[13] The values show that gas and hard coal will become cheaper in 2030, whereas the prices of lignite and nuclear will remain constant.

[12] Ukraine Recovery Plan: Energy.
[13] ENTSO-E Fuel Prices: ERAA 2023 Fuel and Carbon Price Trajectory.

For Moldova, the market gas price was used for the gas power plants on the right bank (CHP and Balti), whereas a reduced gas price of $3.42/GJ was used for MGRES due to the cheap gas supplied by Gazprom (subsidized prices in the left bank region). The fuel price for MGRES was computed to obtain an average short-run marginal cost of $50–65/MWh, given the variable operation and maintenance cost of $20/MWh. The values for the target years are presented in Figure 14Figure 14. Further, in 2030, MGRES can make use of additional gas at the EU-ERAA price of $6.741/GJ to bid with its marginal price.

The fuel prices used in the model resulting in short-run marginal cost values are shown in Figure 15. A comparison of these values for 2025 and 2030 shows that MGRES, hard coal, and lignite become more expensive due to the increase in carbon dioxide (CO2) related costs and the high CO2 production from these types of fuels, while gas and the CHP and Balti power plants become cheaper due to the decrease in gas prices.

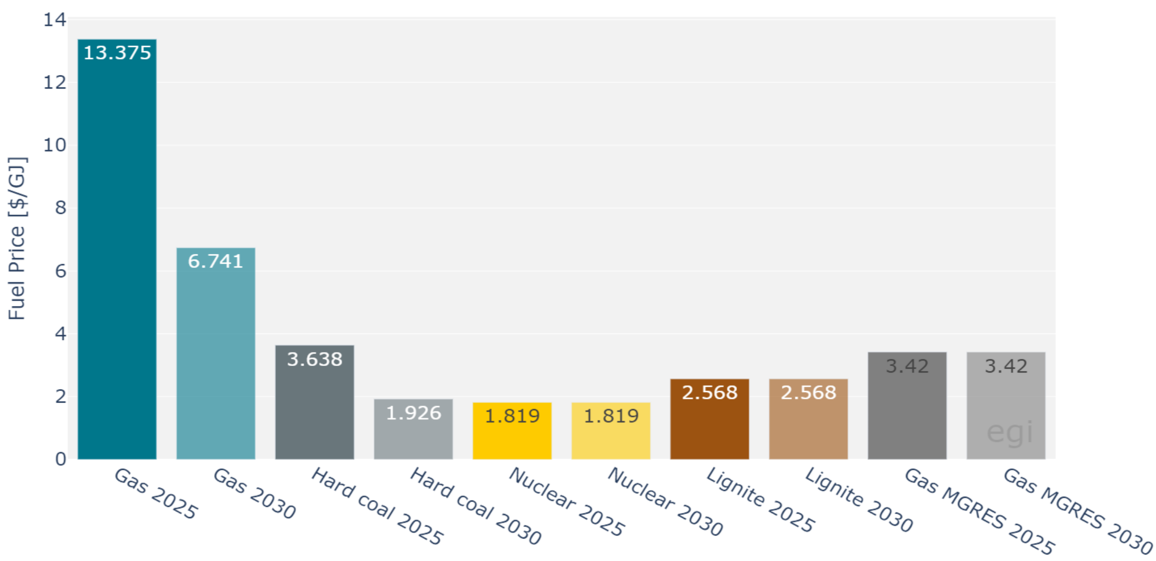

Figure 14 Fuel prices for Moldova, Ukraine, and Romania

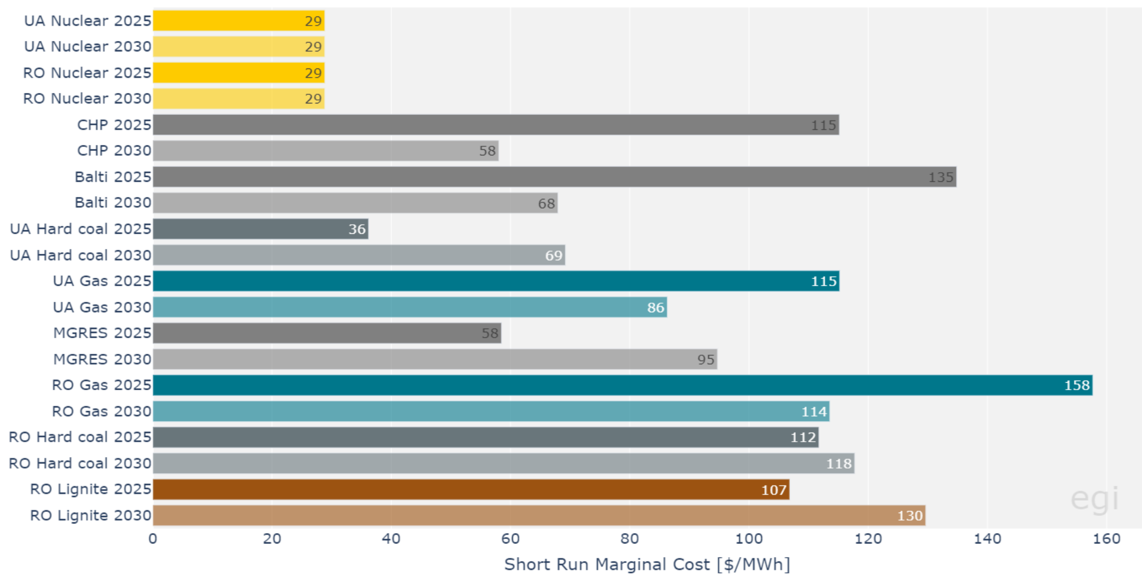

Figure 15 Short-run marginal costs for different generation types in Moldova, Romania, and Ukraine (2030)

4.1.1.4 CONTRACTUAL FUEL LIMITATIONS

The gas supplied to MGRES at a low price by Gazprom is only available in a limited quantity. It is estimated that the current supply of natural gas from Gazprom will maintain a level of 5.7 million cubic meters daily. To reflect this situation, the following assumptions were made for the simulation:

- **Low-price gas:** MGRES receives a monthly gas allocation of 3177 TJ, priced at 3.43 \$/GJ.
- **Market price gas supply:** In 2030 MGRES can make use of additional gas at EU-ERAA price of 6.741 \$/GJ to bid with its marginal price.

4.1.1.5 CO2 PRICING

The new EU Carbon Border Adjustment Mechanism (CBAM)[14] regulations subject carbon-intensive imports to the EU to a carbon tariff. Consequently, for 2030, fossil-fueled units in Moldova and Ukraine will incur a CO2 cost of \$0.0565 per kg. This cost is calculated as half of the EU's carbon tariff rate, which is \$0.113 per kg. This estimation is based on the schedule for phasing out free allowances and their allocated share for the simulated year 2030. Since the pathway for Moldova to join the European Emission Trading Scheme remains unclear, no other CO2 cost were considered in the simulations.

4.1.1.6 INTERCONNECTIONS

The area exchanges were modeled using NTC values allowing no export from Ukraine in 2025. The detailed values are shown in Figure 16. NTC values for EU nodes are based on ERAA data, whereas the NTC values between Moldova, Romania, and Ukraine were set as agreed with Moldelectrica. It can be seen from the figure that increased NTC values are assumed between EU and Romania as well as between Romania and the Right Bank. Further, Ukraine has no export NTC in 2025 but can export in 2030.

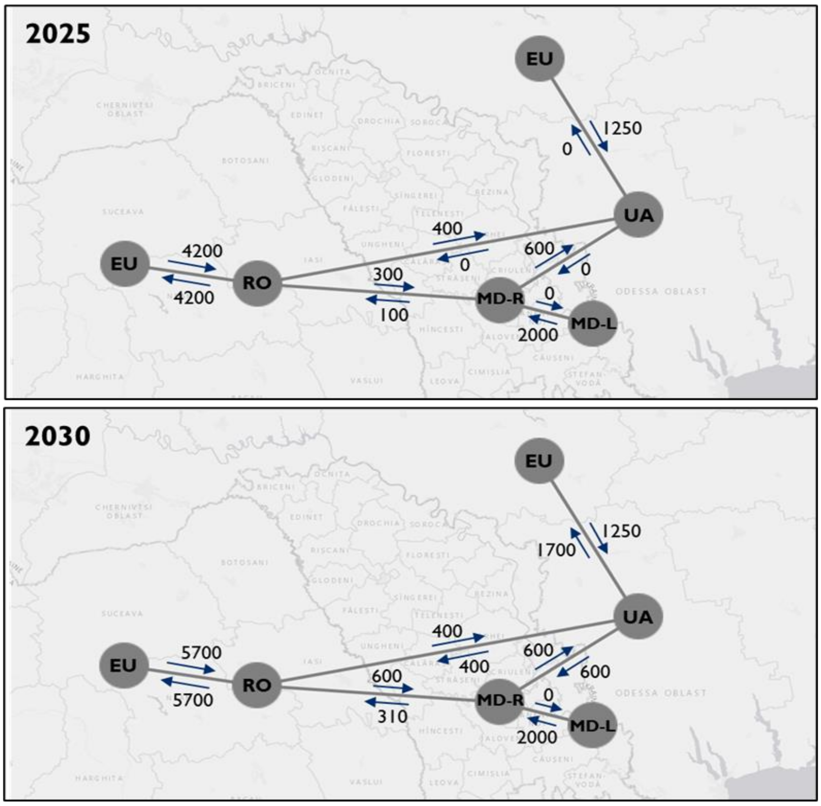

Figure 16 NTC values used in the model for 2025 and 2030

4.1.1.7 MODELING THE REST OF EUROPE

The impact of the rest of Europe was considered in the dispatch optimization model via weekly energy and hourly price signals. The rest of Europe was modeled as two import/export nodes connected to Romania and Ukraine respectively where specific volumes of energy can be traded on a weekly basis

[14] Source: EU CBAM (https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en)

based on historical commercial exchanges and average hourly prices for 2021. The source of this data is the ENTSO-E Transparency Platform, from which hourly data was retrieved and converted to weekly resolution.[15] The weekly granularity covers the seasonal variability of resources. Figure 17 shows the time series of tradable energy between Ukraine and the EU and between Romania and the EU. The Ukraine–EU time series data show that in the past, Ukraine has mostly imported energy from the EU to fulfill its load requirements but exported at the start of the year. The flows between Romania and EU show large annual variations such that no specific seasonal pattern can be observed. The annual tradable energy between the regions is shown in Table 9Table 9. Further, price signals allow the optimizer to buy electricity from the cheaper regions and sell to other areas, depending on the availability and demand in the regions.

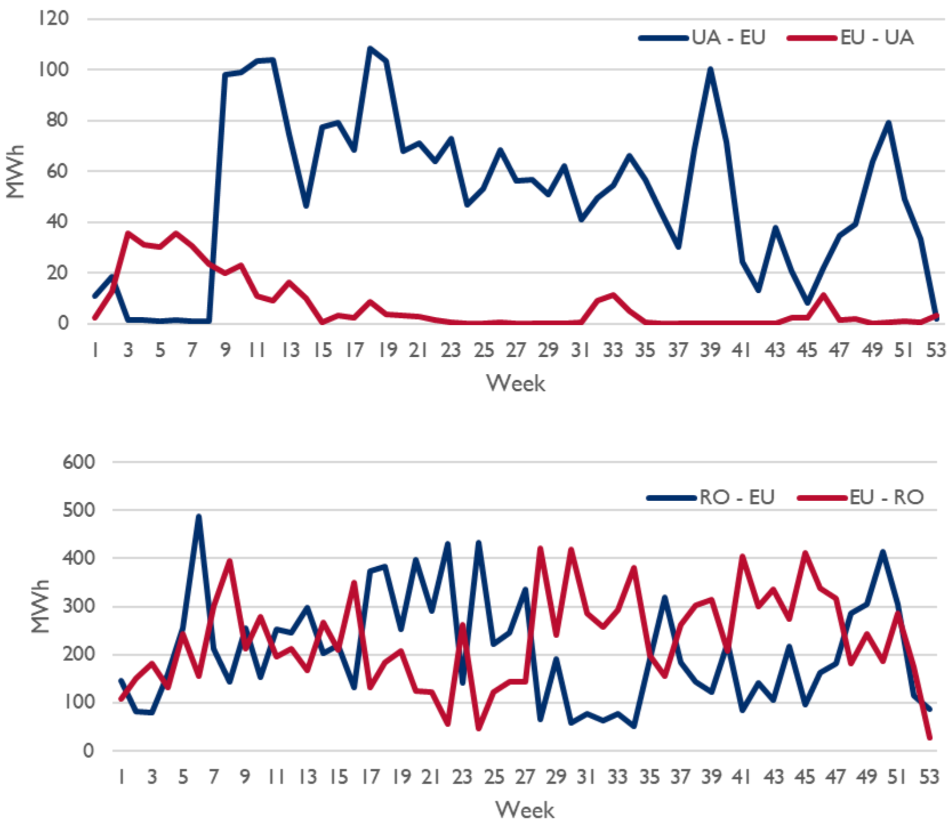

Figure 17 Weekly tradable energy time series for Ukraine and EU (upper) and for Romania and EU (lower)

Table 9 Annual tradable energy, TWh

Romania-EU	EU-Romania	Ukraine-EU	EU-Ukraine
11.1	12.3	2.6	0.37

All the above-mentioned inputs were used to develop a market model, as explained in the next section.

4.1.2 APPROACH

A deterministic unit commitment and economic dispatch simulation on hourly resolution was performed in PLEXOS using the medium-term and short-term scheduling phases for combined system optimization. The model included all technical constraints and respective costs at the unit level, such as plant efficiency, start-up and shutdown times/costs, ramping constraints, must-run requirements,

[15] ENTSO-E Transparency Platform, https://transparency.entsoe.eu/

and hydropower plant constraints. Furthermore, all key contractual constraints, such as gas supply contracts, were depicted in detail as discussed above.

4.1.3 RESULTS

The results of the dispatch analysis are presented in two sections. First, the overall results related to generation mix and tie line flows are shown for Moldova, Romania, and Ukraine, followed by a deep dive into some detailed aspects.

4.1.3.1 OVERALL RESULTS

This section presents comprehensive results regarding the operation of the power system and the flows on the interconnectors. The results are divided into two groups: 1) Moldova's right and left banks and 2) Romania and Ukraine, as shown in Figure 18; these are then further subdivided for the target years 2025 and 2030.

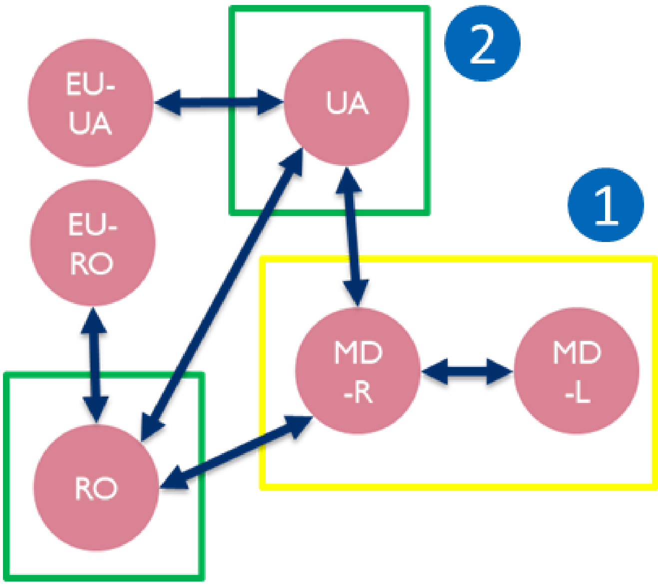

Figure 18 Group 1: Moldova's left and right banks and three tie lines (yellow box); Group 2: Romania and Ukraine and remaining tie lines (green box)

For each group and target year, a comprehensive figure shows the details as follows (Figure 19 to Figure 22):

- The plot on the top left shows the generation mix for the scenario considered as the baseline.
- The smaller plots at the bottom contain delta graphs showing the difference between each scenario and the baseline.
- The plot on the top right shows the flows on concerned interconnectors.
- The map in the center of the figure shows data on which group is contained in the figure.
- All values are in TWh.

<u>2025 Moldova</u>

The 2025 results for the left and right banks are shown in Figure 19. The baseline plot shows that 43% of the load of the Right Bank is met by local generation, while 55% is met by MGRES, and a mere 0.2% is imported from Romania. In scenarios incorporating MGRES, there is a noticeable decrease in MGRES production as the penetration of RES on the Right Bank increases. This reduction is compensated by an increase in imports from Romania, as indicated by the steep blue line representing the tie line flow from Romania in Figure 19, in these scenarios compared to the scenario with MGRES.

Moreover, the contribution of MGRES to the Right Bank is substituted with an increase in imports from Romania and a decrease in exports to Ukraine in scenarios without MGRES. It is also noteworthy that in all scenarios excluding MGRES, the region on the Right Bank of the Nistru River experiences unserved energy.

2030 Moldova

The data for 2030, as depicted in Figure 20, outlines the energy distribution for the Left and Right Banks. The baseline plot demonstrates that the Right Bank meets 72.5% of its load through local generation, while 25% is covered by imports from Romania and Ukraine, and a negligible 1% comes from MGRES. Moldova serves as a significant power hub experiencing substantial energy flows between Romania, the Right Bank, and Ukraine.

2025 Romania and Ukraine

The data for 2025, as illustrated in Figure 21, provides insights into the energy dynamics for Romania and Ukraine. The baseline plot indicates that Romania is unable to fulfill its local load requirements and consequently imports approximately 12.3 TWh from the European Union. In the scenarios incorporating MGRES, an increase in RES penetration in the Moldova Right Bank does not significantly affect Romania and Ukraine. However, in the scenarios excluding MGRES, there is an observable increase in energy generation in both Romania and Ukraine, which can be attributed to heightened exports towards the Right Bank of Moldova.

2030 Romania and Ukraine

For 2030, the results for Romania and Ukraine are shown in Figure 22. The baseline plot shows that Romania does not meet its local load fully and imports ~12.3TWh from the EU neighboring counties. In the scenarios 2030, Fast RES exports from Moldova to Ukraine reduces fossil-based generation in Ukraine.

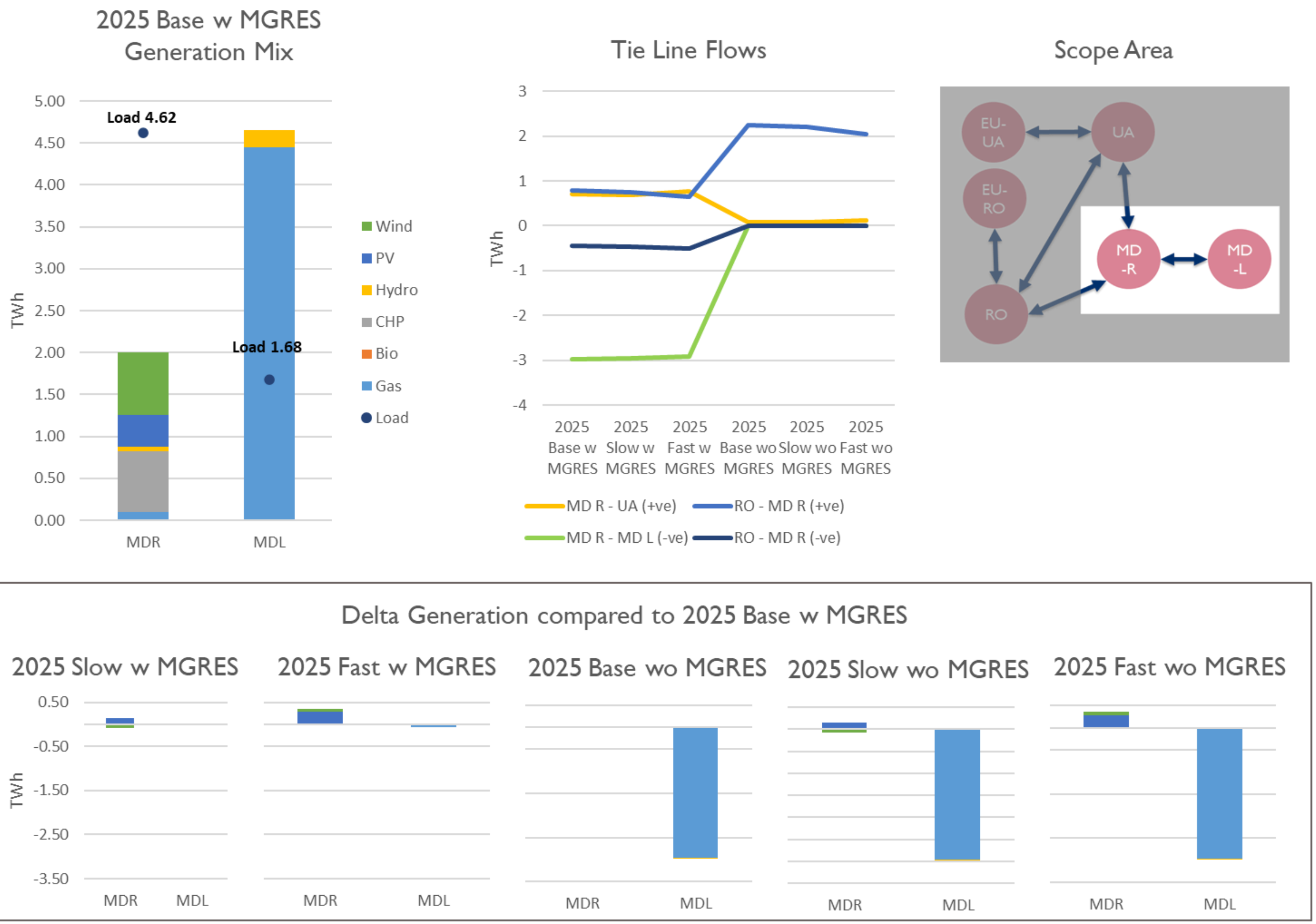

Figure 19 Results for 2025 MD: Generation mix for Base with MGRES scenario (top left), delta graphs for with and without MGRES (bottom), and tie line flows (top right)

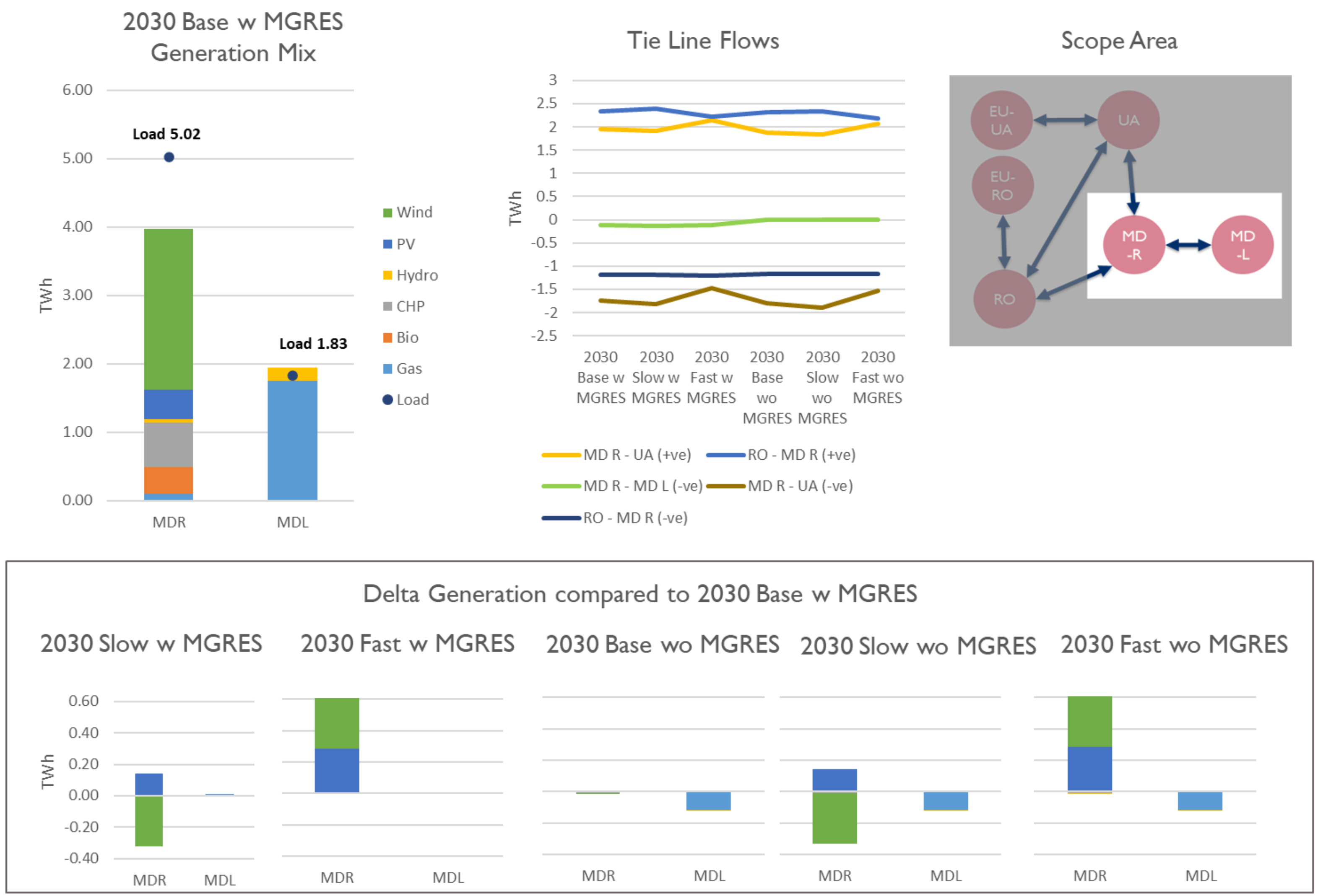

Figure 20 Results for 2030 MD: Generation mix for Base with MGRES scenario (top left), delta graphs for with and without MGRES (bottom), and tie line flows (top right)

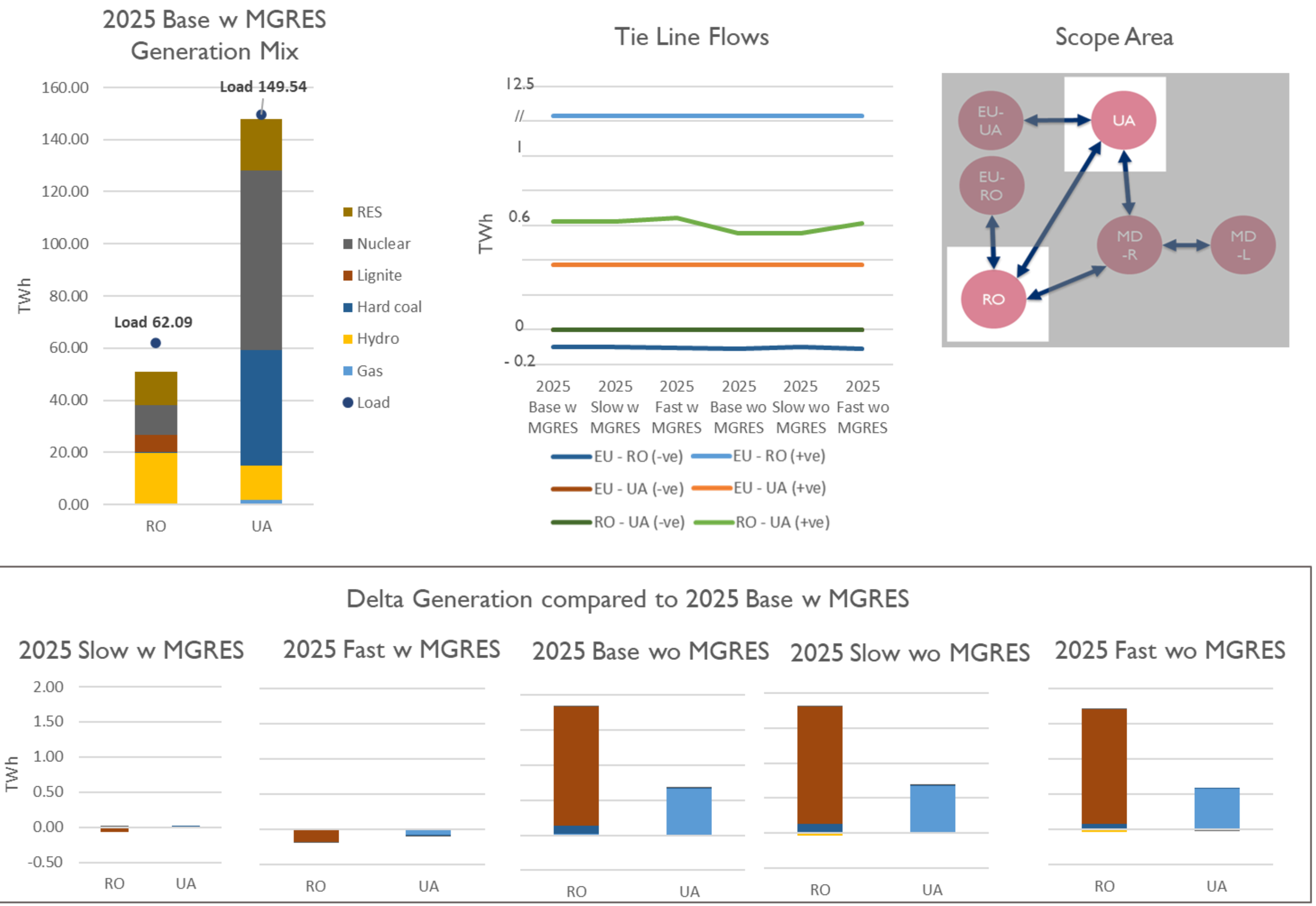

Figure 21 Results for 2025 Romania and Ukraine: Generation mix for Base with MGRES scenario (top left), delta graphs for with and without MGRES (bottom), and tie line flows (top right)

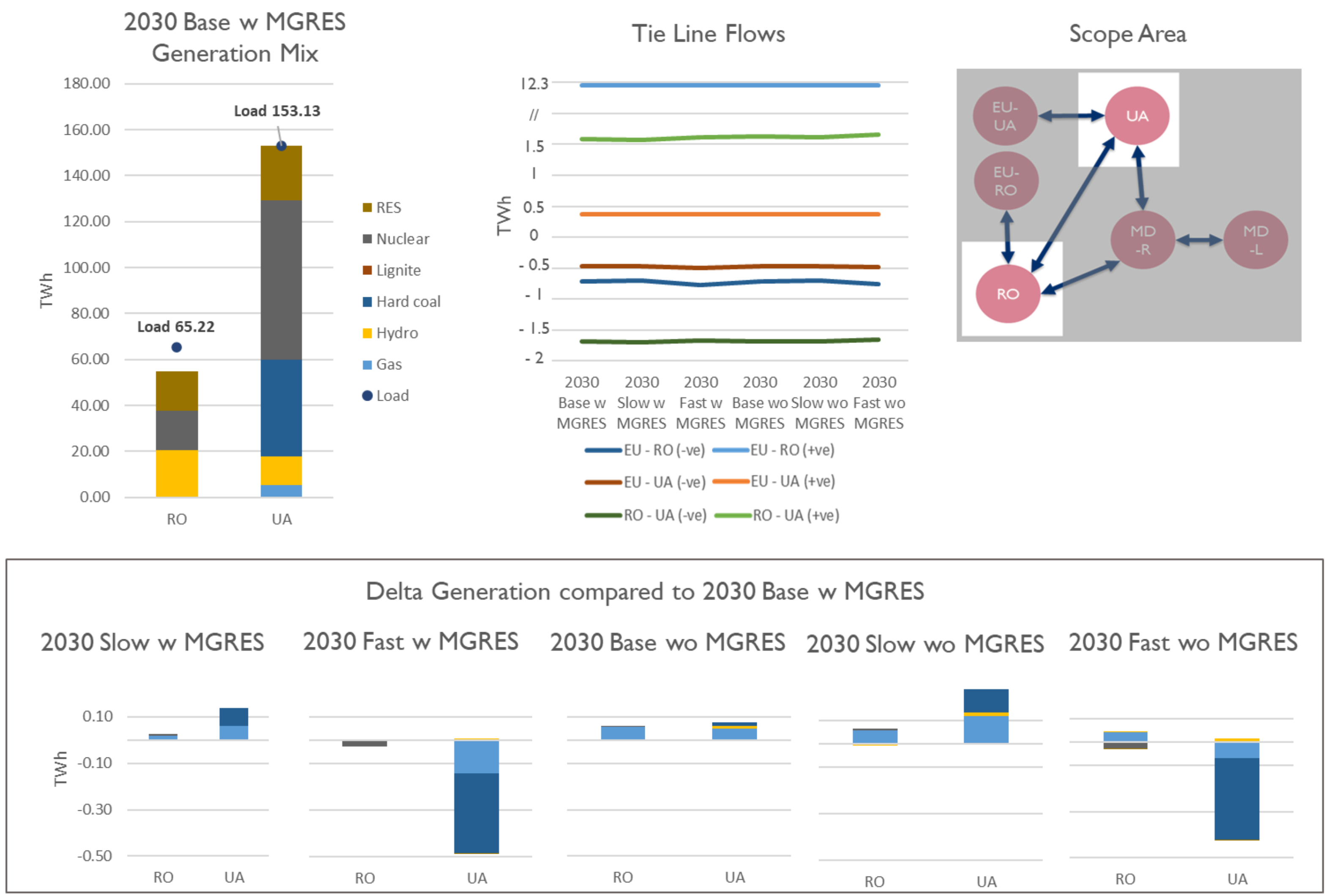

Figure 22 Results for 2030 Romania and Ukraine: Generation mix for Base with MGRES scenario (top left), delta graphs for with and without MGRES (bottom), and tie line flows (top right)

Figure 23 compares the generation mixes in 2025 and 2030, showing that Romania and Ukraine are shifting toward cleaner energy production with increased RES and nuclear power while reducing lignite-based generation. For Ukraine, there is an increase in RES and gas production, while production from hard coal decreases. For Moldova, an increase in wind and bio can be seen in 2030, which leads to a reduction in MGRES's production in the left bank.

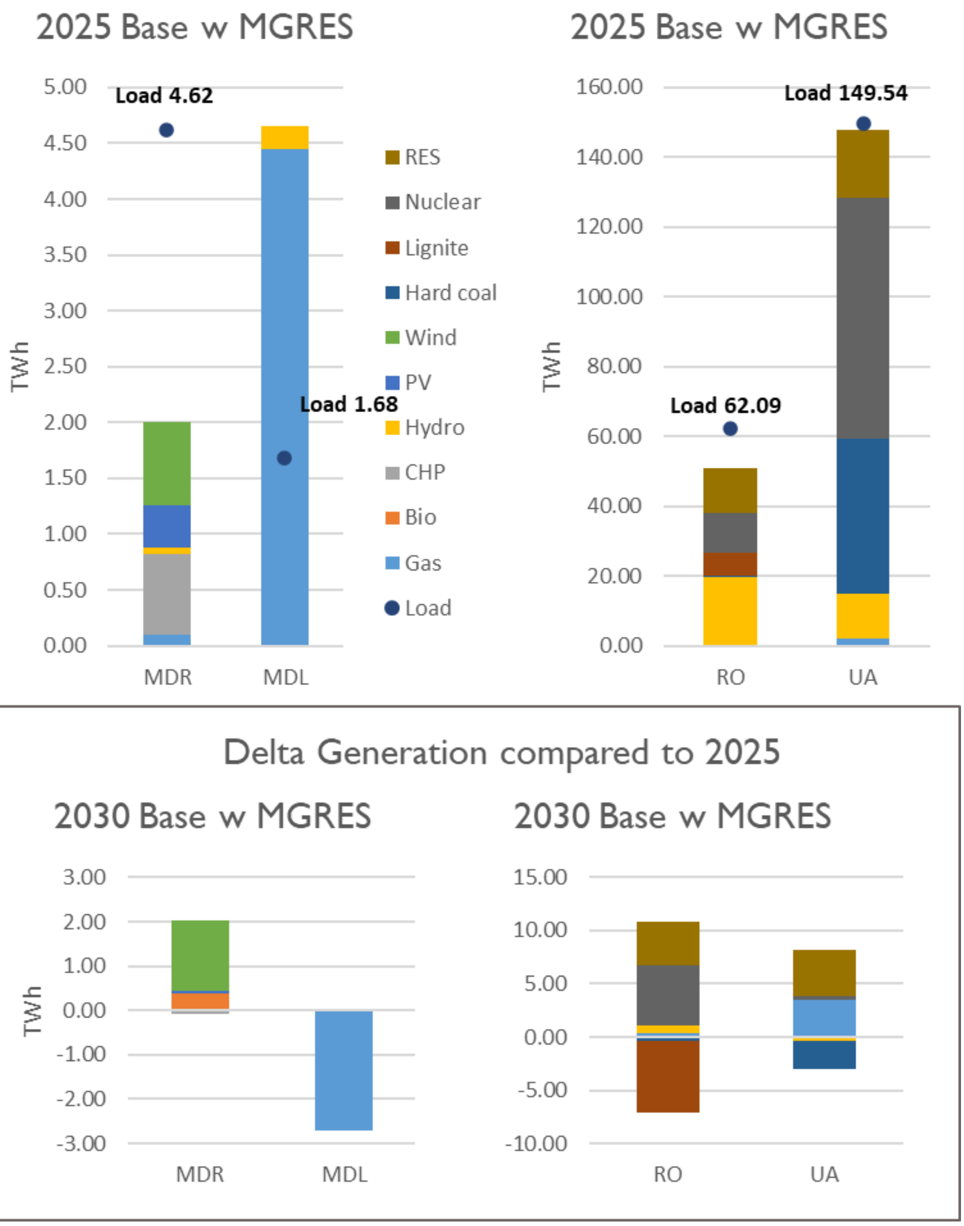

Figure 23 Comparison of generation mixes, 2025 and 2030

An overview of area exchanges between the regions for Base scenarios in 2025 and 2030 with MGRES is shown in Figure 24, indicating the direction of energy flows and the values in TWh. In 2030, Moldova's right bank becomes less dependent on MGRES and has higher exports. This bank also moves from higher imports in 2025 to higher exports in 2030 due to increased RES. Further, the exports from the left bank decrease over this period significantly due to increased capacity on the right bank. For Romania, there is a significant increase in imports from the EU in 2030 due to lower prices in the EU, while Ukraine becomes a prominent exporter in 2030, still having significant imports from Moldova's right bank.

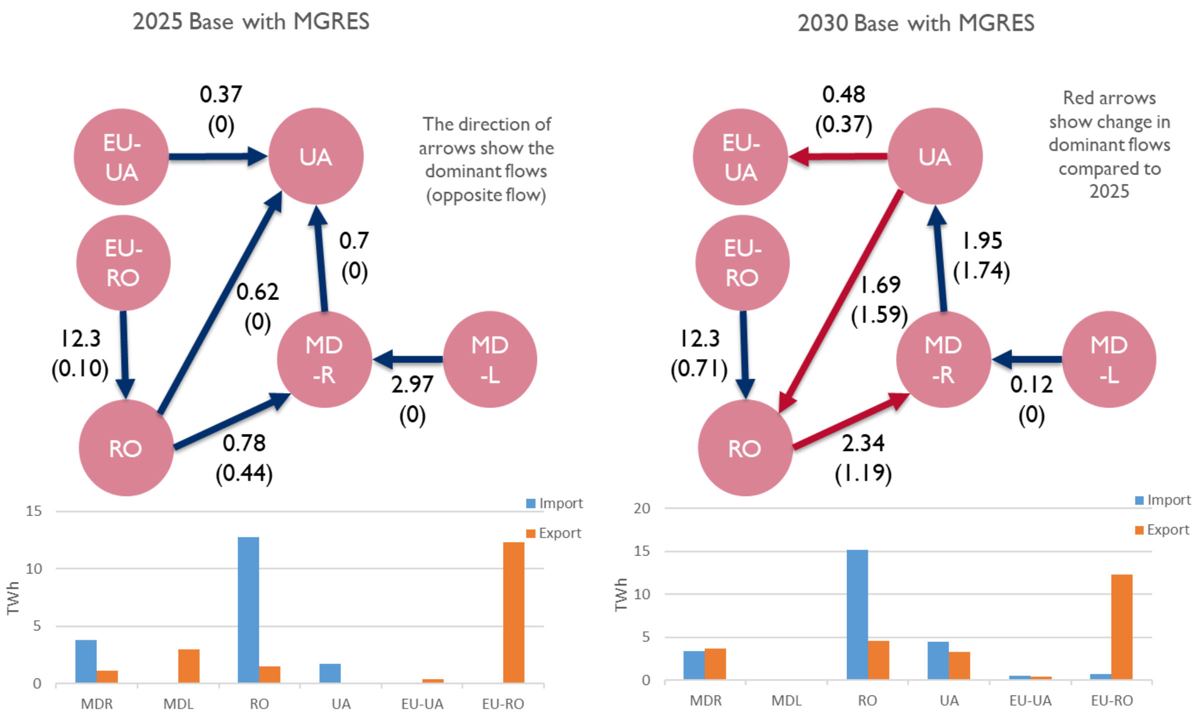

Figure 24 Results of area exchanges for Base scenario with MGRES, 2025 and 2030

4.1.3.2 DEEP DIVES ON SYSTEM BEHAVIOR

This section presents an in-depth analysis on the following aspects of the overall results.

1. **Large flows from Romania to Ukraine via the right bank**

The right bank has loop flows in winter from Romania toward Ukraine due to Ukraine's high load and relatively small NTC with other regions. Figure 25 shows an example of such loop flows from January 1, 2025, where the lines between Romania and Moldova's right bank, the right bank and Ukraine, and Romania and Ukraine are at their maximum NTC values in the hours between 6 a.m. and 3 p.m.

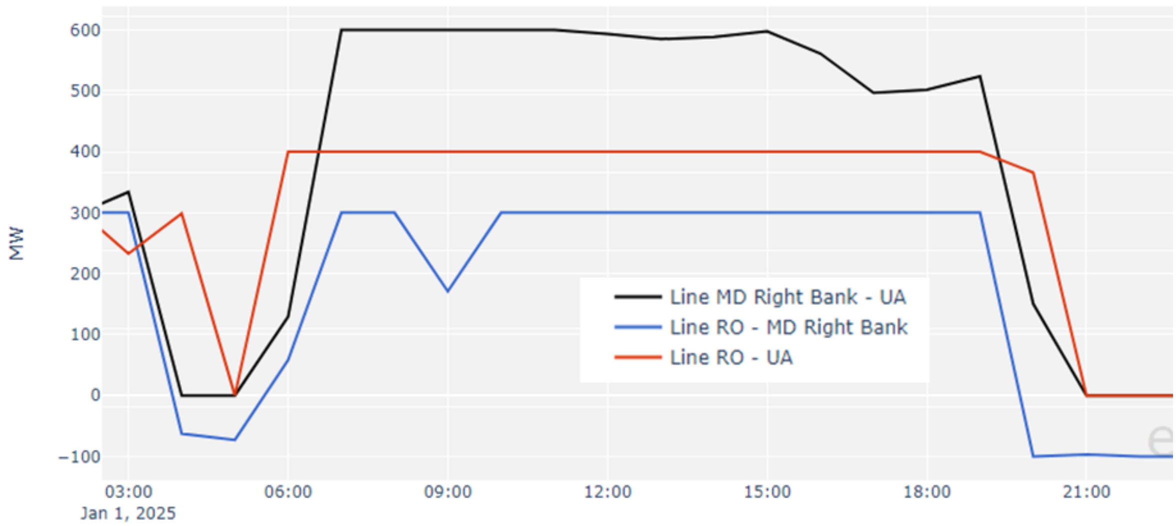

Figure 25 Example of large flows from Romania to Ukraine via Moldova's right bank, January 1, 2025

Figure 26 shows that this situation happens mainly in winter, for about 3 percent of the year when the flows on the tie lines are at their maximum NTC values.

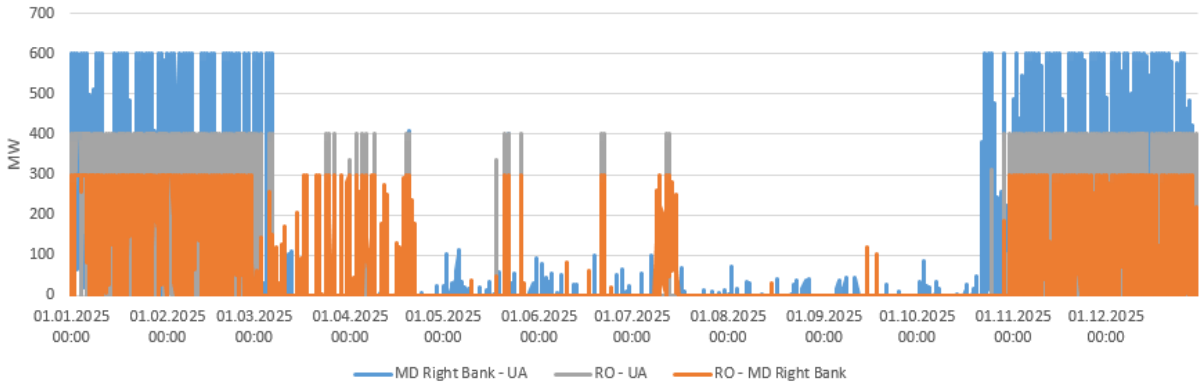

Figure 26 Tie lines between Romania, Moldova's right bank, and Ukraine are at maximum NTC values mainly in winter months

2. Romania's high level of imports from the EU

Romania imports around 12.3 TWh from the EU in both 2025 and 2030 due to the EU's cheaper generation. Figure 27 shows the flow on the EU–Romania interconnector and the prices in both regions. In areas 1 and 3, the price in Romania is higher than the generation price in the EU; therefore, Romania imports from the EU. In area 2, the price in Romania is lower than the generation price in the EU, so Romania exports to the EU.

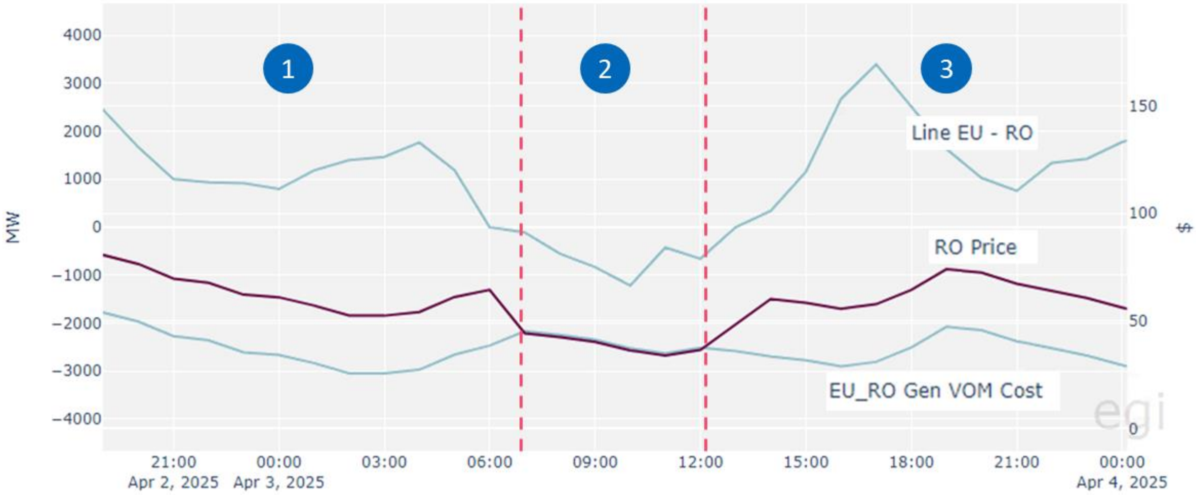

Figure 27 Romania has high imports from the EU due to cheaper EU generation

3. Occurrence of unserved energy on the right bank

Unserved energy on the right bank occurs in 2025 for all scenarios without MGRES due to limited NTC with Romania. An example is shown in Figure 28, where the load on Moldova's right bank is 670 MW, while generation is 180 MW and imports from Romania are at their maximum value of 300 MW. This leaves Moldova's right bank with unserved energy of 190 MW. The figure also shows that unserved energy occurs mostly in winter months. The total unserved energy for different RES scenarios without MGRES in 2025 is shown in Table 10: unserved energy is between 75 and 95 GWh, with the peak in the range of 327–331 MW.

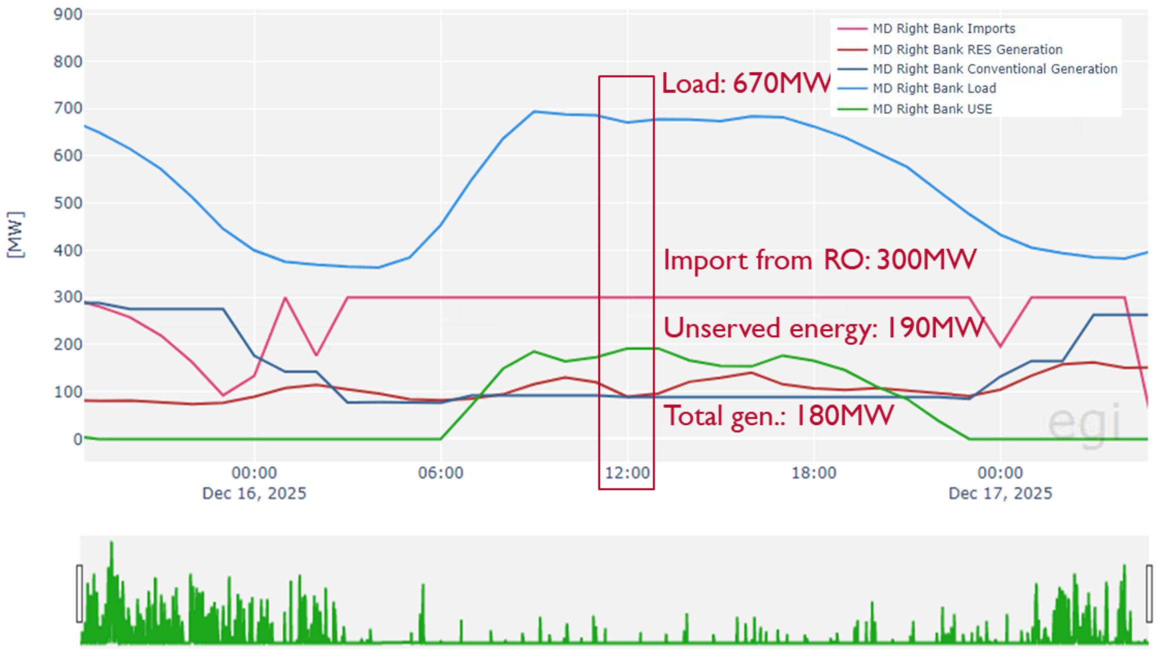

Figure 28 Unserved energy on the right bank in all 2025 scenarios without MGRES due to limited NTC with Romania

Table 10 Total unserved energy and peak value for RES scenarios without MGRES in 2025

Scenario	Unserved Energy [GWh]	Peak [MW]
Base	95	329
Fast	75	327
Slow	94	331

4.1.4 CONCLUSIONS

Generation dispatch and inter-area flows were calculated using a PLEXOS simulation model for Moldova, Romania, and Ukraine plus the rest of Europe. Results show the following.

For 2025:

- The right bank has insufficient capacity to meet its local load and depends on MGRES, without which there is unserved energy. The unserved energy peaks in winter, with a maximum value of about 330 MW.
- The increase in RES penetration on the right bank reduces dependency on MGRES.

In 2030:

- Due to increased RES and bio generation, Right Bank is reducing its MGRES dependency and has increased exports.
- The results of scenarios without MGRES show no difference from scenarios with MGRES; therefore, to simplify, the former scenarios may be omitted from further analysis.
- The right bank acts as a transport hub between Romania and Ukraine and has loop flows in winter months.
- Romania has significant imports from the EU due to expensive local generation.
- Both Romania and Ukraine shift toward RES and gas production and away from coal.

4.2 ADEQUACY ASSESSMENT

This section presents the input data, approach, and results for the probabilistic adequacy assessment. The objective of the probabilistic adequacy assessment is to identify the scenarios that are adequate for assessing system flexibility needs.

4.2.1 INPUT DATA

4.2.1.1 CREATION OF TEMPERATURE-DEPENDENT LOAD TIME SERIES

An essential input for modeling power systems is the electricity demand modeled in the form of load time series. As the generation model is developed at an hourly resolution, the electrical load time series used are also at an hourly resolution. To improve the statistical significance of the results, more than one time series was used per scenario and per zone (Moldova's left and right banks) to model electrical load. Although other meteorological variables can influence the electrical load (e.g., wind speed), it was chosen to consider only temperature's impact on electrical load for this study. This is standard practice at Elia Group and ENTSO-E and is judged sufficient for long-term studies.[16] The load time series creation process, which was applied to each zone separately, is shown in Figure 29Figure 29 Process for load time series construction.

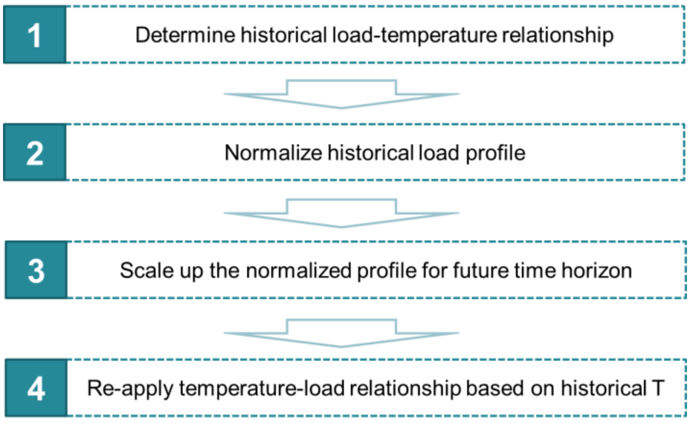

Figure 29 Process for load time series construction

The first step in creating the load time series was to determine the load-temperature relationship based on historical data. Moldelectrica provided separate historical load time series for the left and right banks for 2017–2022. The same temperature data were used for both zones; these were obtained from the open-source database of Renewables.Ninja,[17] which uses NASA MERRA reanalysis[18] and CM-SAF's SARAH[19] dataset as its sources.

To capture the load-temperature relationship for both zones, different polynomials were calibrated through a least-square approach, as shown in Figure 30. A third-order polynomial is the best fit to capture both the heating and cooling effects, and higher orders do not show a significant increase in deviations. Also, a better and logical saturation of the impact at very high and low temperatures is seen for the third-order polynomial fit.

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[16] Elia Adequacy and Flexibility Study for Belgium 2022-2032, ENTSO-E MAF Report 2019.

[17] Renewables Ninja, https://www.renewables.ninja/

[18] RIENECKER MM, SUAREZ MJ, GELARO R, TODLING R, ET AL. (2011). MERRA: NASA'S MODERN-ERA RETROSPECTIVE ANALYSIS FOR RESEARCH AND APPLICATIONS. JOURNAL OF CLIMATE, 24(14): 3624-3648. DOI: 10.1175/JCLI-D-11-00015.1

[19] SARAH DATASET. DOI: 10.5676/EUM_SAF_CM/SARAH/V001

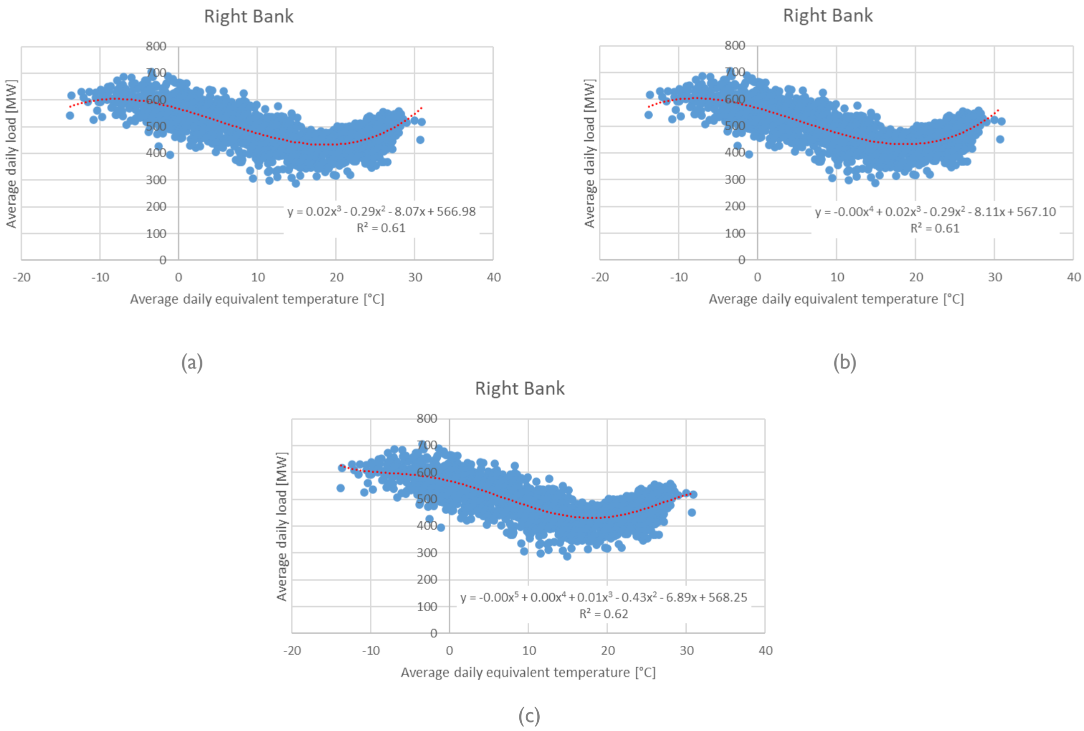

Figure 30 Load-temperature relationship for the right bank for different polynomial fits: (a) third-order polynomial, (b) fourth-order polynomial, and (c) fifth-order polynomial.

The temperature effect can be removed from historical load profiles using the load-temperature relationship determined for each zone. Based on the difference between a specific day's temperature and the normal temperature, the load-temperature relationship allows the construction of an electric load profile for normal temperatures. This process is referred to as "normalization for temperature" and results in a "normalized profile." Figure 31 shows the 2022 load profile and its normalized profile for the right bank. The figure also shows the 2022 temperature as well as the normal temperature, which was constructed by averaging 23 historical years.

In order to study future load evolutions, the normalized load profile was then scaled to obtain desired peak loads for the specific scenarios considered. The target peak loads for each scenario and zones are shown in Table 11.

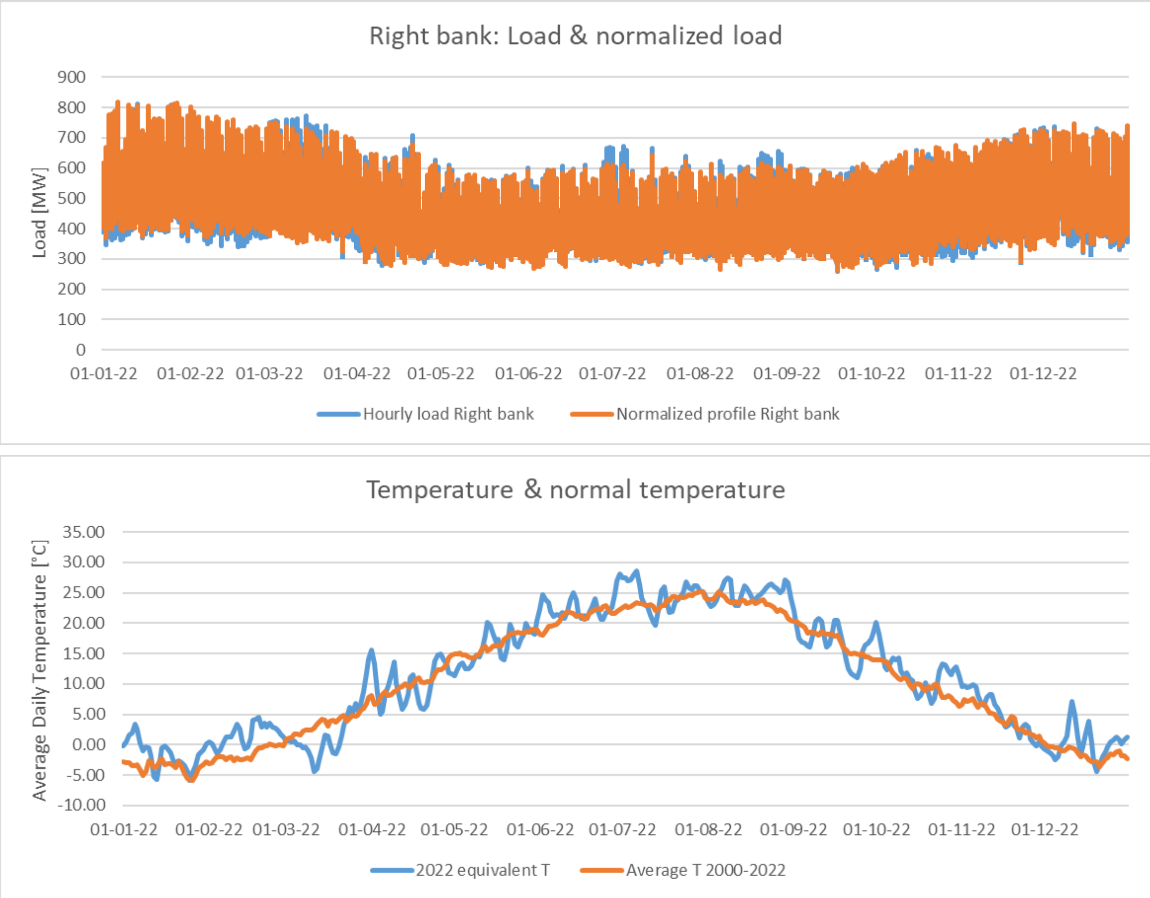

Figure 31 Illustration of a normalized load profile for the right bank

Table 11 Target peak loads used to scale up the normalized load profile

Year	Right bank	Left bank
2025	854	433
2030	929	471

The final step in the load time series construction process was the re-application of temperature effects based on historical temperatures and the previously determined load-temperature relationship. This created a set of 23 load time series for each of the years 2025 and 2030 separately for both zones. The peak values for each load time series set are plotted in Figure 32, which shows that this method results in a variety of load time series to be used in the probabilistic Monte Carlo generation adequacy assessment.

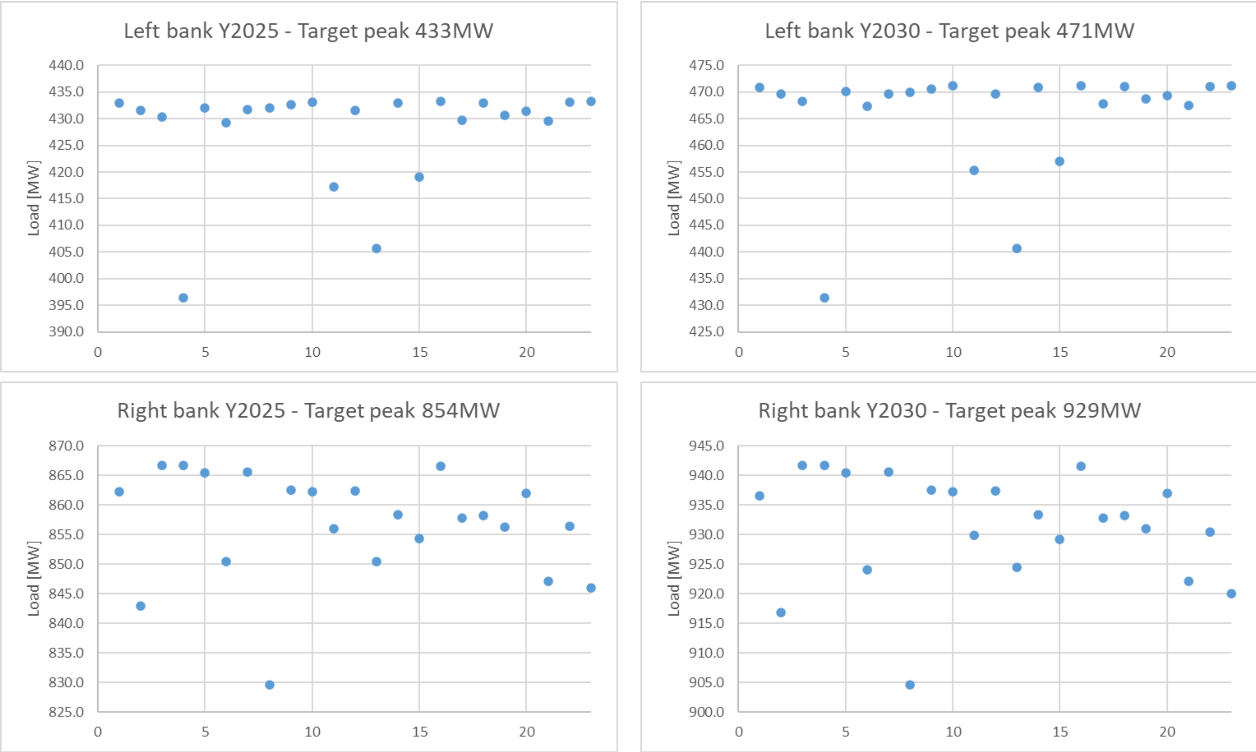

Figure 32 Peak values of the resulting set of load time series for different scenarios and zones

4.2.1.2 RES TIME SERIES

The team obtained 23 years of time series data for PV and wind energy, covering the period from 2000 to 2022, from Renewables.Ninja used them as inputs in the model's analysis.

4.2.1.3 FORCED OUTAGE PARAMETERS

The forced outage rate for each generator in Moldova's power system is reported in Table 2. This generator characteristic is used in PLEXOS to set the expected level of unplanned outages that result in a partial or complete loss of generating capacity for a certain period of time.

4.2.2 APPROACH

4.2.2.1 MONTE CARLO SIMULATION BASED ON ERAA METHODOLOGY

Monte Carlo simulations use random sampling to model uncertainties by creating combinations of load and RES availability and generation forced outages. In this study, multiple sets of random forced outages were generated for each climate year (M forced outage samples per climate year). A sample size of M equal to 150 was taken for outage patterns, and 23 climate scenarios (N) were defined, representing historical climate years. Climate years were selected from 2000 to 2022, where each climate year consists of temperature-dependent load time series and RES (wind and PV) capacity factor time series.

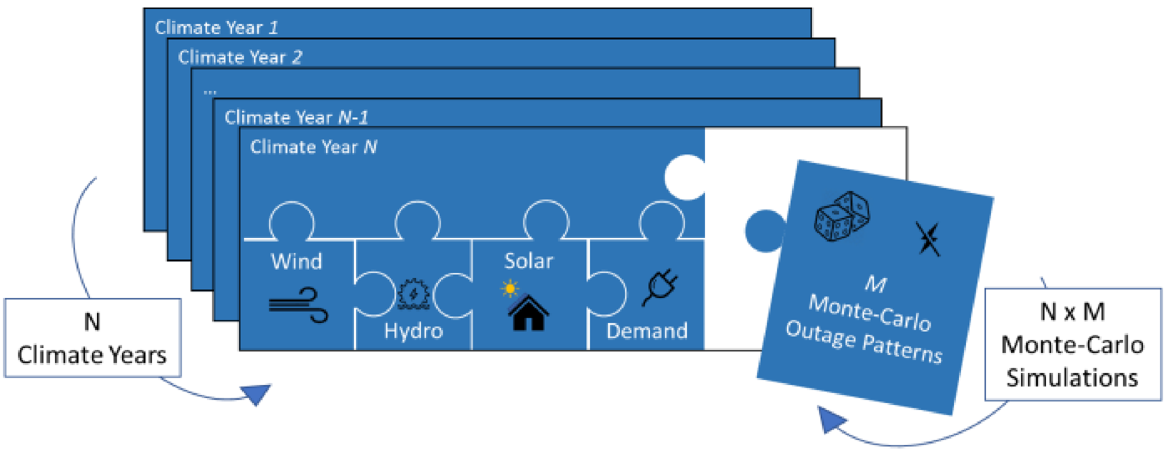

Figure 33 Monte Carlo simulation approach for a given target year

4.2.2.2 ADEQUACY INDICATORS USED

The adequacy indicators of LOLE and EENS were used to assess the adequacy of the system. These indicators are defined as follows and shown in Figure 34:

- Energy not served (ENS) [GWh] – sum of demand that cannot be met due to insufficient resources (e.g. available generation, imports)
- Expected ENS (EENS) [GWh] – expected demand that cannot be met due to insufficient resources; calculated as the average ENS over the number of samples
- Loss of load duration (LLD) [h] – number of hours in which resources are insufficient to meet demand
- LOLE [h] – expected number of hours in which resources are insufficient to meet demand; calculated as the average LLD over the number of samples.

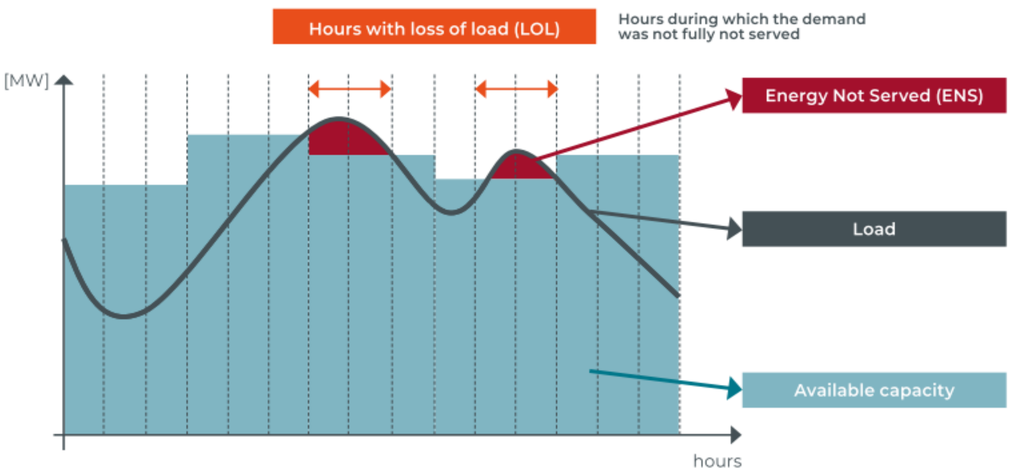

Figure 34 Representation of adequacy indicators LOLE and EENS

The LOLE threshold value for Moldova was calculated using the Association for the Cooperation of Energy Regulators (ACER) methodology. This approach defines LOLE as the ratio of the cost of new entry to the value of lost load. For Moldova, the cost of new entry for combined-cycle gas turbines (CCGTs) was estimated at €50/kW/year, equivalent to approximately $54,000/MW/year. The Dividing Moldova's annual GDP ($13.68 billion) by its annual electricity consumption (3.8 TWh) produced a value of lost load of around $3,600/MWh. This calculation led to a LOLE threshold of 15 hours, a value that is comparable to that of Czechia, as illustrated in Figure 35.

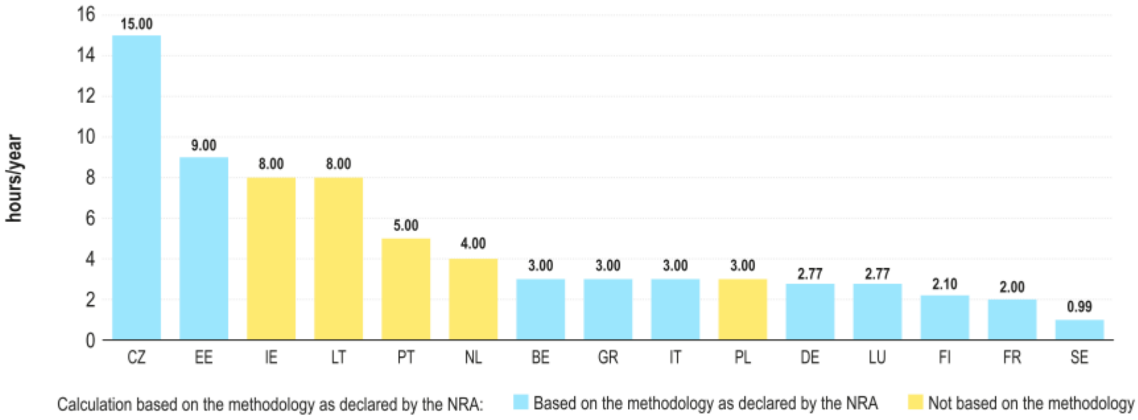

Figure 35 LOLE threshold[20]

4.2.3 RESULTS

4.2.3.1 ADEQUACY RESULTS

The adequacy results for the right bank, in terms of ENS, are shown in this sub-section. ENS represents the amount of energy not served, therefore, the lower its value the more reliable the system. Table 12 shows that in 2025, without MGRES, the system is inadequate because of a high ENS. The lowest ENS occurs in the RES Fast scenarios, which are the scenarios with the highest RES installed capacity.

Table 12 Right bank EENS (average) and ENS percentiles for all scenarios

Scenario	EENS (Average) [MWh]	ENS (P50) [MWh]	ENS (P95) [MWh]
2025 RES Base w MGRES	11.16	0	0
2025 RES Base wo MGRES	80,767.74	80,193.15	97,997.16
2025 RES Fast w MGRES	4.59	0	0
2025 RES Fast wo MGRES	64,015.7	63,571.84	77,293.01
2025 RES Slow w MGRES	10.36	0	0
2025 RES Slow wo MGRES	81,168.74	80,618.24	97,399.62
2030 RES Base w MGRES	0	0	0
2030 RES Base wo MGRES	0	0	0
2030 RES Fast w MGRES	0	0	0
2030 RES Fast wo MGRES	0	0	0
2030 RES Slow w MGRES	0	0	0
2030 RES Slow wo MGRES	0	0	0

The LOLE values for the right bank in 2025 and 2030 are shown in Table 13Table 13, which shows that without MGRES in 2025, LOLE for all RES scenarios exceeds the estimated LOLE threshold of 15 hours. For an adequate system the LOLE value should be close or equal to zero.

20 ACER.

Table 13 Right bank LOLE (average) and LLD percentiles for all scenarios

Scenario	LOLE (Mean) [h]	LLD (P50) [h]	LLD (P95) [h]
2025 RES Base w MGRES	0.12	0	0
2025 RES Base wo MGRES	1,127.74	1,115.50	1,304.40
2025 RES Fast w MGRES	0.05	0.00	0.00
2025 RES Fast wo MGRES	907.01	897.50	1,056.65
2025 RES Slow w MGRES	0.11	0.00	0.00
2025 RES Slow wo MGRES	1,125.51	1,119.50	1,281.55
2030 RES Base w MGRES	0	0	0
2030 RES Base wo MGRES	0	0	0
2030 RES Fast w MGRES	0	0	0
2030 RES Fast wo MGRES	0	0	0
2030 RES Slow w MGRES	0	0	0
2030 RES Slow wo MGRES	0	0	0

4.2.3.2 ROBUSTNESS

To be robust, Monte Carlo simulation results must converge, meaning that the impact of additional Monte Carlo results on existing results should be small or negligible. The following indicators are used to assess convergence, based on the ERAA methodology:[21]

- Incremental average ENS – average ENS across all samples per scenario for a certain number of samples
- Coefficient of variation, α, of EENS – describes volatility of EENS metric in Monte Carlo assessment and is calculated as follows:

$$\alpha_N = \frac{\sqrt{Var[EENS_N]}}{EENS_N}$$

  Where EENS is the average ENS over N, the number of Monte Carlo years.

- Relative change of α – coefficient of variation relative to the number of samples

Figure 36 shows the incremental average ENS for scenarios with and without MGRES, which stabilizes at 150 samples, thus confirming the robustness of the simulation.

[21] ERAA Methodology for the European Adequacy Assessment.

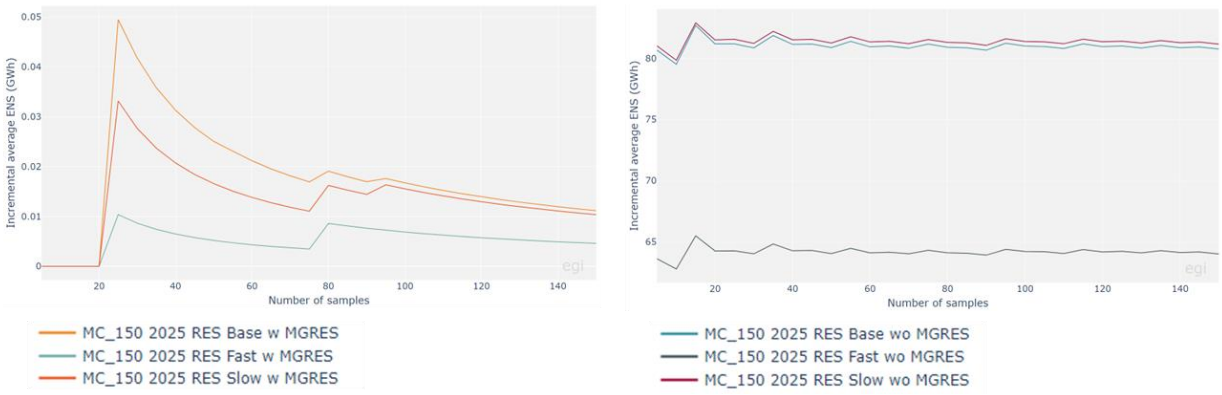

Figure 36 Incremental average ENS for scenarios with MGRES (left) and without MGRES (right)

The relative change of α converges to 0, as shown in Figure 37Figure 37, confirming the robustness of the simulation. This value is also very small to begin with, compared to ERAA results, further validating that 150 samples are sufficient.

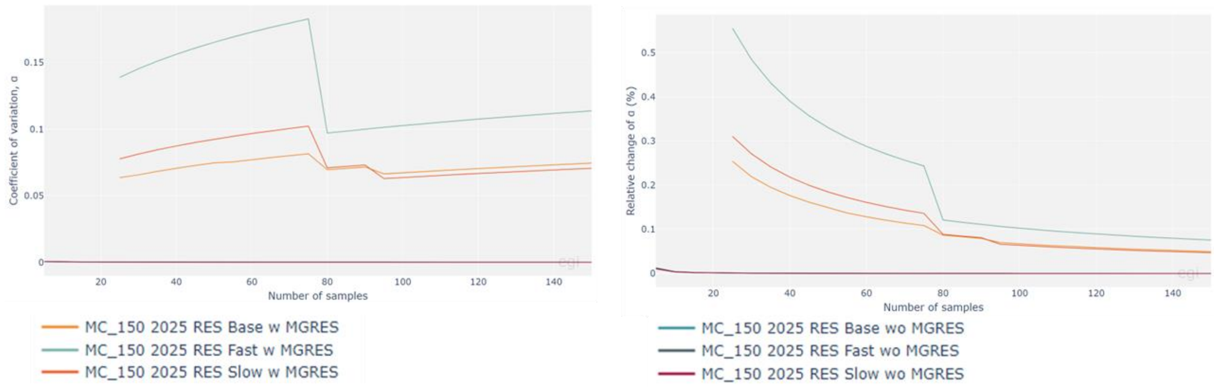

Figure 37 Coefficient of variation of α (left) and relative change of α (right) for all scenarios

4.2.4 CONCLUSIONS

A probabilistic adequacy assessment was carried out for the target years 2025 and 2030. In 2025, without MGRES, the system is inadequate, with EENS of at least 60 MWh and LOLE of at least 900 hours for all RES scenarios. Monte Carlo results converged with 150 samples, confirming the robustness of the Monte Carlo simulation and the sufficiency of the chosen number of samples. Finally, the probabilistic analysis led to the exclusion of the scenarios without MGRES for 2025.

5 DEFINITION OF NEW ASSET TECHNOLOGIES

This chapter corresponds to Activity 3 of the inception report.

The objective was to identify the most appropriate asset to fulfill the reserve requirements identified in Chapter 3 in terms of asset technology, capacity, and the optimal location to maximize system support. This objective was accomplished through a structured three-step process.

First, a comprehensive screening was undertaken, involving a thorough examination of local and international design standards, operational standards, CESA, and other European network codes. The aim was to pinpoint the technology best suited to addressing various reserve types. BESS was identified as optimal for fulfilling aFRR requirements, while ICEs emerged as suitable for mFRR needs.

Second, the optimal capacity of these assets was determined. The BESS unit's sizing was computed through a detailed simulation, analyzing imbalances at one-minute resolution. This simulation yielded the power and energy content required by the BESS unit to effectively cover all imbalances. Simultaneously, the ICE's capacity was dimensioned to encompass upward mFRR needs, with an additional backup unit.

The third and final step involved simulating the new assets within the grid model at preselected locations, considering the availability of gas and supporting infrastructure. The objective was to identify the most suitable locations, minimizing the cost of connecting the assets and avoiding grid problems. A nodal analysis was performed in PowerFactory for selected critical snapshots of adequate scenarios based on the dispatch simulated from Chapter 4 and injecting rated power at the new assets' locations. This comprehensive analysis examined the suitability of the locations for the new assets, respecting the grid capacity.

The first step is described in this chapter, while the second and third steps are discussed in Chapters 6 and 7 respectively.

5.1 AVAILABLE TECHNOLOGIES

5.1.1 BATTERY ENERGY STORAGE SYSTEM (BESS)

In recent years, BESS technology has become a mainstream technology for providing balancing services in several parts of the world, including Europe. Batteries can provide a very fast response to imbalances and can provide upward and downward regulation, meaning that the BESS is either charged or discharged depending on the sign of the imbalance.

Presently, the most mature technology is the lithium-ion battery cell, because of its high energy density and efficiency, and fast response speed. Other technologies, such as lead acid, redox flow, sodium sulfur, or sodium ion, were not considered in this study because they are either not suitable or competitive for the provision of balancing services or because their market is not yet mature enough.

Lithium-ion battery cells are characterized by different cell chemistries. For stationary storage, the current mainstream chemistry is the lithium-iron-phosphate cell (LFP), which has replaced the lithium-nickel-manganese-cobalt cell (NMC) for many implementations. The LFP cell offers lower costs and better safety than NMC, with the disadvantage of having a low energy density, thus making the system heavier. This limitation can be a problem in certain mobile applications (electric vehicles) but usually not in stationary storage applications. The NMC technology can also sustain higher C-rates, i.e., higher rates of (dis)charge.[22] For this reason, NMC was considered in the study together with LFP for cases where the design optimization would lead to a high C-rate BESS. Details on technical and commercial attributes of LFP and NMC batteries are given in Table 14 and Table 15 respectively. The main components of the BESS are:

- Battery racks
- Power conversion systems (PCS or inverters)
- Medium/low-voltage transformers
- Medium-voltage switchgears
- High/medium-voltage transformer
- High-voltage switchgear
- Auxiliaries (heating, ventilation, and air conditioning; fire detection and suppression; etc.)
- Battery management system
- Energy management system

Table 14 Technical attributes of LFP and NMC BESS

Description	LFP BESS	NMC BESS
Start-up time to full load (minutes)	Less than 1 second	
Round-trip efficiency	~85%	
Degradation	~5% per 1,000 cycles	
Maximum C-rate	1C	2C
Energy density (cell)	100–150 Wh/kg	Up to >300 Wh/kg
Typical BESS module size (utility-scale)	0.5 to 5 MVA; modules can be added in parallel without limitation to reach required power	
Expected cycle life	6,000 to 8,000 cycles (until 60% of initial capacity)	
Calendar life	20 years	

Table 15 Commercial attributes for LFP and NMC BESS

Description	Cost LFP and NMC batteries
CAPEX	CAPEX is between \$400 and \$600/kWh, including grid connection. Cost of battery racks is determined by energy capacity (in MWh), while the cost of PCS and grid connection is determined by power capacity (in MW).

[22] C-rate is the measurement of current at which a battery is fully charged or discharged.

Description	Cost LFP and NMC batteries
Operating expenses (OPEX) and maintenance costs	OPEX is determined by the cost of the energy lost during the charge/discharge cycle (15% losses if round-trip efficiency is 85%). Operation and maintenance cost is between 0.5% and 1.5% of CAPEX. Additional costs can be incurred if the degradation is compensated by the addition of new cells to maintain initial capacity.

5.1.2 FAST THERMAL UNITS

To meet the operational requirements of mFRR, different technology options are available, including open-cycle gas turbines (OCGTs)—aeroderivative turbines—and ICEs. Both technologies offer their own sets of advantages and limitations.

The performance of power plants at partial load has emerged as a significant operational consideration for electric power grids. This is particularly relevant as the operating regimes of thermal power plants evolve from pure baseload to balancing variable renewable energy. Thermal power plants are increasingly required to function as cycling units with constantly varying load profiles, often operating at part load. Consequently, the part-load performance of a balancing power plant is becoming a critical factor in minimizing fuel costs and emissions while maximizing operational flexibility.

This technical comparison focuses on evaluating the range of output and part-load efficiency of reciprocating ICEs and aeroderivative gas turbines. The analysis is based on the data provided by original equipment manufacturers (OEMs), and the site conditions were also taken into consideration. The comparison aims to provide insights into the suitability and performance of both technologies for the specific needs of mFRR.

The technical parameters for OCGT and ICE are presented in Table 16. ICE offers more flexibility in terms of less start time, higher ramp rates, and part-load efficiency.

Table 16 Technical properties of OCGT and ICE

Description	OCGT	ICE
Ramp rate (in spinning mode, %/min)	50	100
Start-up time to full load (minutes)	5–8	2–5
Plant net efficiency	37–40% (OCGT can be considered if it will convert to CCGT in the future. By utilizing exhaust heat, CCGT will have efficiency of more than 55%.)	45–48% (lower fuel consumption and relatively lower variable cost in the electricity tariff). By utilizing exhaust heat, the efficiency can be increased to 55%.
Modular design	Yes, with some limitations	Yes, but there are limited companies offering a frame size of 15–20 MW. More companies offer a 10 MW frame size.
Part-load efficiency	Less than ICE	Higher than OCGT

Description	OCGT	ICE
Natural gas fuel pressure at inlet of machine	Pressure requirement at inlet is at least 24 bar. A compressor is required to increase the pressure from 12 bar to 24 bar.	The piped gas pressure can be around 10 to 11 bar or in the range of 6 to 7 bar. Need to plan pipe sizes and control infrastructure accordingly, thereby avoiding any booster compressor (and its CAPEX/OPEX).

** The comparative figures have been sourced from the OEMs' catalogs.*

The commercial attributes for ICE and OCGT are presented in Table 17. Overall CAPEX and OPEX for both technologies are similar, but ICE has higher fuel efficiency than OCGT.

Table 17 Commercial attributes for OCGT and ICE

Description	Cost, OCGT and ICE	
CAPEX	Per MW ex-works price (excluding balance of plant [BOP]) of OCGT is comparable with ICE at $606,000/MW) per MW ex-works price (excluding BOP, bill of materials, site and land, etc.).	
OPEX and maintenance costs	$18,150/MW per year, which represents 3% of machine cost.	
Fuel consumption	The heat rate of OCGT is higher than that of ICE, which means the OCGT requires higher fuel to generate the same amount of energy than does ICE. OCGT: ~0.34 m^3/kWh Fuel consumption is approximately 20-25% higher than for ICE	The heat rate of ICE is lower than that of OCGT ICE: ~0.22 m^3/kWh Fuel consumption is approximately 20-25% lower than for OCGT

5.2 SELECTION OF SUITABLE TECHNOLOGY

5.2.1 FCR AND aFRR

Thermal units that are solely utilized for balancing encounter two challenges. First, if these units are only activated during an imbalance, their startup duration may be excessively long and may incur startup costs. Second, these units operate continuously to adjust generation for balancing, their average production output needs to be procured based on commercial trade of electricity, meaning that the units will be dispatched similar to must runs.

It's important to note that the inflexibility of existing assets in Moldova is largely a result of the country's Soviet Era power plants, which have limited load-following capabilities. Additionally, CHP plants are driven by heat demand, further contributing to inflexibility. MGRES is not an option, since any participation to the electricity market of Moldova (including for the electricity generation) can be arbitrarily and abruptly stopped because of political reasons. Moreover, Moldova has limited water resources for a HPP project that would contribute to the load frequency control process in the near future. Finally, the existing unit at Costesti HPP is too small to impact the current situation on the malfunction balancing market.

To provide FCR and aFRR reserve support of the system, this study recommends the adoption of BESS, as it offers many advantages over conventional thermal generation (e.g., OCGT or ICE):

- **Fast Response Time:** BESS offers an exceptionally fast response time by responding to frequency deviations within milliseconds. This rapid response is crucial for effectively addressing sudden changes in power demand or supply and maintaining grid stability.
- **Precision and Accuracy:** BESS provides precise and accurate control over the frequency, allowing for fine-tuning and better adherence to grid frequency requirements. This degree of control is essential for maintaining a stable and reliable power system.
- **Dynamic Performance:** The dynamic performance of BESS enables it to smoothly integrate with the grid and respond to fluctuations in real-time. This capability is especially valuable in handling the inherent variability of renewable energy sources. Therefore, this technology represents a important solution given the high inflexibility of available thermal generation in Moldova (old technology with lack of flexibility or operation with must-run constraints).
- **Grid Support During Contingencies**: BESS can act as a reliable backup during contingencies, ensuring grid stability and preventing potential blackouts. Its ability to rapidly inject or absorb power makes it a valuable asset in emergency situations.
- **Enhanced Grid Resilience**: Considering the nature of Moldova grid, BESS will help absorb shocks and disturbances, minimizing the impact of unexpected events on the grid.
- **Quick Deploymen**t: BESS is quick to deploy, with deployment times ranging from 10-12 months.
- **Adaptability to System**: BESS is adaptable to various grid conditions and can be deployed in different locations based on the specific needs of the grid. The modular design of BESS allows geographical split of units (for redundancy) and adjustment to local connection requirements.
- **Proven Solution**: BESS is a proven and economic solution for FCR support. There are many international applications of the technology for example, Germany has 630MW of prequalified BESS to provide FCR. Batteries are also mostly used in Belgium to provide FCR support.
    - BESS has the most optimal operational flexibility amongst all the available technologies because they can ramp upward and downward in a range of seconds.
    - BESS is a proven and economic solution for FCR support. There are many international applications of the technology, for example, Germany has 630MW of prequalified BESS to provide FCR. Batteries are also mostly used in Belgium to provide FCR support.
- The modular design of BESS allows geographical split of units (for redundancy) and adjustment to local connection requirements.

For these reasons, BESS is the preferred technology for short-term grid balancing. The systems have a very short reaction time and can thus react almost immediately to imbalances. The main issue with BESS is its limited energy reservoir. This is not a problem for FCR, which is expected to operate for only 15 minutes until aFRR takes over.

For aFRR, however, the power system may face longer periods of same-sign imbalances, in which case BESS could reach the limits of its capacity (full BESS in cases of positive imbalance, empty BESS in cases of negative imbalance). For this reason, the provision of aFRR with BESS has to be combined with an energy management strategy in which other assets (e.g., thermal units or flexible demand) will be activated in order to restore the state of charge of the batteries in case of important imbalances.

Globally, 42GW/99GWh of BESS have been deployed until end 2023 according to Bloomberg New Energy Finance (Bloomberg NEF)[23] and a compound annual growth rate of 27% is expected until 2030 (Figure 38). These BESS are for short-term balancing[24] including ancillary services such as aFRR and FCR.

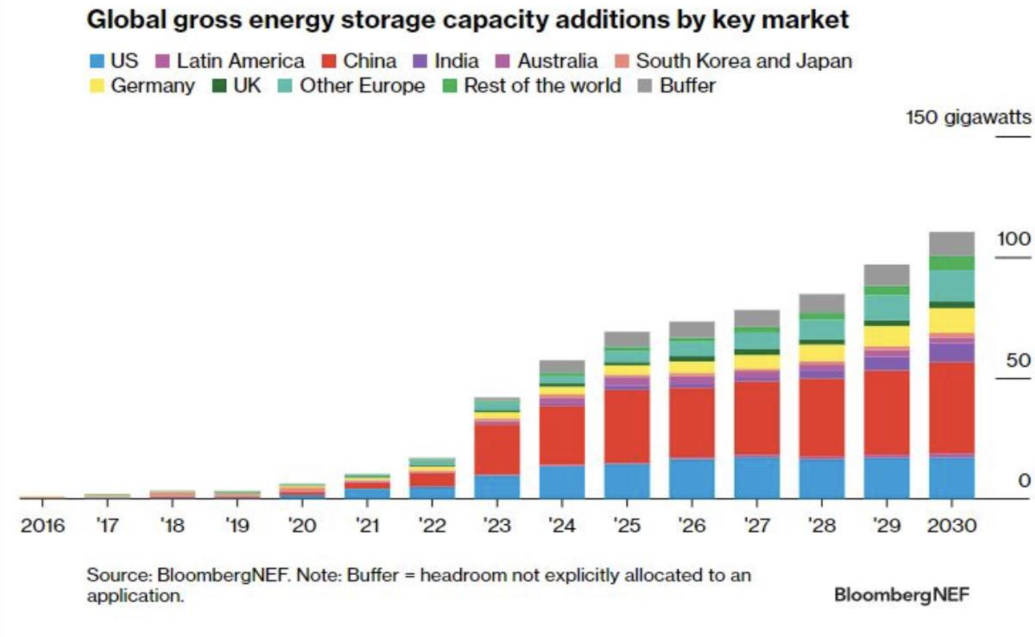

Figure 38 Global BESS capacity addition (source BNEF)

Also, in the US, the use of BESS for ancillary services has seen a substantial rise in ERCOT. This trend is largely attributed to the escalating demand and price volatility, which are consequences of the rapid expansion of intermittent renewable capacity. The increasing reliance on BESS for ancillary services underscores their growing importance in maintaining grid stability.

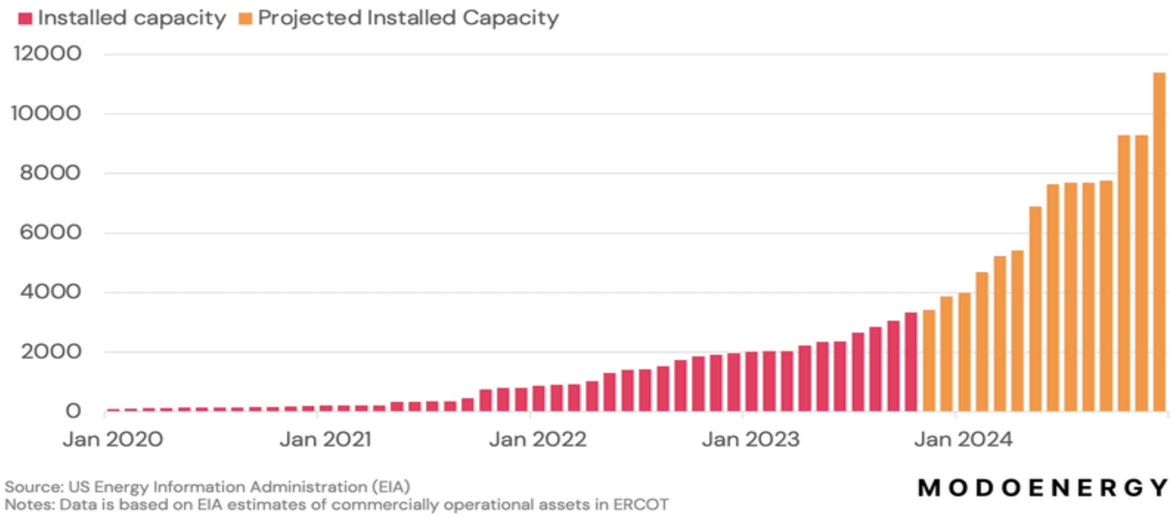

Figure 39 ERCOT BESS capacity (MW) increased by 12x in the last three years.

23 https://about.bnef.com/blog/2h-2023-energy-storage-market-outlook/

24 https://www.iea.org/energy-system/electricity/grid-scale-storage

5.2.2 mFRR

Opting for ICEs over aeroderivative turbines presents several advantages. One key consideration is the superior operational efficiency of ICEs, especially during part-load conditions. Unlike aeroderivative turbines, ICEs demonstrate a higher efficiency rate, ensuring optimal performance even when operating at varying load profiles. This characteristic is particularly significant in scenarios requiring continuous load-following capability, where ICEs showcase better responsiveness and adaptability to fluctuations in power system loads. Additionally, the cost-effectiveness of ICEs, in terms of both initial investment and ongoing operational expenses, contributes to their appeal as a preferred choice. The ability of ICEs to meet environmental standards and emission limits, even at lower loads, further enhances their suitability for diverse operational conditions. Therefore, the decision to select ICEs over aeroderivative turbines is driven by a holistic consideration of efficiency, flexibility, and cost-effectiveness in meeting the specific requirements of the power generation landscape.

5.3 MARKET ANALYSIS OF SELECTED TECHNOLOGIES

5.3.1 BESS

For BESS, the value chain is split up between:

- Battery cell manufacturers: major suppliers include Contemporary Amperex Technology Co. Limited and BYD for LFP cells, and Samsung SDI and LG Chem for NMC cells.
- Integrator: integrates the battery cells (or modules) with a PCS (converter), an energy management system, and the required auxiliaries (heating, ventilation, and air conditioning, etc.)

Some of the main utility-scale BESS providers who are active in Europe are listed in Table 18. At the moment, their projects use LFP cells almost exclusively because the majority of BESS last between two and four hours, i.e., their C-rates are between 0.25C and 0.5C (LFPs are cheaper and can go up to a C-rate of 1).

Table 18 Utility-scale BESS providers

	Available EPCs	Country
1	Fluence	United States
2	Tesla	United States
3	NHOA	Italy
4	Alfen	Netherlands
5	Wartsila	Finland

5.3.2 FAST THERMAL

5.3.2.1 AVAILABILITY ANALYSIS

The market analysis for ICEs in the context of flexibility requirements from various OEMs underscores the enduring importance of ICEs across diverse industries. Recognizing the need for adaptable power solutions, OEMs are driving demand for ICEs that offer versatility, reliability, and customization options.

Table 19 shows the major ICE OEMs along with the available engine rating/frame size.

Table 19 Major ICE manufacturers

Available OEMS	Available ICE Rating
Wartsila	2 to 18 MW
Hyundai	2.7 to 21.8 MW
MAN Energy Solutions	3.06 to 20 MW
Caterpillar	3.990 MW
Rolls-Royce Solutions Gmbh	2 MW
Daihatsu	5.93 MW
Fairbanks Morse Defense	3.6 MW
INNIO Waukesha Technology	3.7 MW
MWM	4.5 MW
Mitsubishi Heavy Industries	5.7 MW
WinGD	2.7 to 20 MW
IHI Power Systems	2.8 to 19.2 MW
INNIO Jenbacher Technology	10.6 MW

5.3.2.2 CONCLUSION

To encourage vendor participation, the optimal range for consideration is between 10 MW and 20 MW, or even exceeding 20 MW for frame size. Within this range, the study team identified six or seven OEMs with offerings that align with the specified frame size. The efficiencies of these systems fall within the range of 30 percent to 40 percent.

Table 20 Final results of the market analysis for ICE technology

Options	Available OEM	Participation	Efficiency	Competitive Offer	Variable operation and maintenance costs	Overall Cost
5 to 10 MW	8	Higher	Lower	Yes	Higher	Higher
10 to 15 MW	6	Moderate	Higher	Yes	Moderate	Moderate
15 to 20 MW	5	Lower	Higher	No	Moderate	Moderate

For both budgetary estimations and technical considerations, following evaluation of available units and prices on the market, it was considered sufficiently accurate to evaluate the indicative price of an 18MW unit, listed at 11.08 million USD, Ex-Works. This serves as a representative benchmark when assessing factors such as cost, size, and technical specifications.

6 DEFINITION OF NEW ASSET CAPACITY

This chapter corresponds to Activity 3.4 of the inception report.

6.1 CAPACITY CALCULATION OF ASSET FOR FCR NEEDS

A BESS with size of 5 MW and 5 MWh is recommended to meet the current FCR requirements. The one-hour battery backup is justified by two facts:

- FCR needs to be provided for 15 minutes; therefore, BESS needs at least 30 minutes of capacity storage to be able to provide up and down frequency control with a 50 percent target state of charge before activation.
- With a limited energy reservoir, BESS is usually required to provide one hour of energy.

In Western Europe, BESS units have been taking part in FCR markets for several years. For example, Centrica (formerly REstore) has been providing FCR to Elia since 2018 with its Terhills 18 MW BESS in Belgium.[25] Other TSOs using BESS for FCR (through a market, not as asset owners) include Amprion, RTE,[26] National Grid, and Tennet.[27]

6.2 CAPACITY CALCULATION OF ASSET FOR aFRR NEEDS

The assessment of the optimal sizing of BESS for aFRR needs is a complex analysis, as the optimal size of the battery (in terms of energy storage capacity, in hours) depends on the volatility of expected system imbalances. Sustained imbalances in one direction necessitate larger BESS capacity, while imbalances that change rapidly from one direction to the other can be managed by smaller energy storage systems. To assess the optimal BESS/ICE combination, a detailed analysis of the operation of the system was performed, considering the volatility of system imbalances and the possible energy management strategies for the combined asset. Based on that analysis, this section includes a rigorous assessment of the appropriate size for these assets to meet aFRR requirements. Different ICE/BESS configurations were assessed under various energy management strategies. The assessment of key techno-economic indicators enables the selection of an optimal combination of assets to provide aFRR.

6.2.1 INPUT DATA

The foundational data for the analysis were the imbalance time series from the probabilistic assessment of balancing needs identified in Chapter 3, specifically tailored to the 2030 Fast scenario as representative of the largest aFRR requirements. These imbalance time series, at one-minute resolution, serve as an indicative measure of anticipated system volatility. To align with the aFRR provisioning requirements, this data was meticulously filtered and adjusted within the aFRR operational range, adhering to the sizing outcomes predicated on system adequacy and future amplitude standards, which dictate that aFRR sizing is contingent upon the volatility of the system.

The analysis assessed the following combinations of BESS and ICEs:

- BESS: Three BESS energy storage sizes were considered:
    - 72 MW/72 MWh (one-hour)

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[25] https://www.centricabusinesssolutions.com/us/news/restore-completes-one-europes-largest-grid-scale-battery-schemes
[26] https://www.services-rte.com/files/live/sites/services-rte/files/pdf/mecanisme%20d%27ajustement/rte%20balancing%20report%202022_vf.pdf
[27] https://knowledge.energyinst.org/new-energy-world/article?id=127383

- 72 MW/144 MWh (two-hour)
- 72 MW/288 MWh (four-hour)

- ICE: Based on the ICE unit technical parameters from Chapter 5, the size of the ICE unit is 18 MW, and it can deliver full power in five minutes. Two sizes for the system were considered, namely two ICEs (36 MW) versus four (72 MW).

6.2.2 APPROACH – ENERGY MANAGEMENT STRATEGY

To evaluate the appropriate scaling of BESS and ICE assets for aFRR deployment, an analysis of diverse operational strategies employing various BESS/ICE configurations was conducted alongside a mapping of crucial performance metrics.

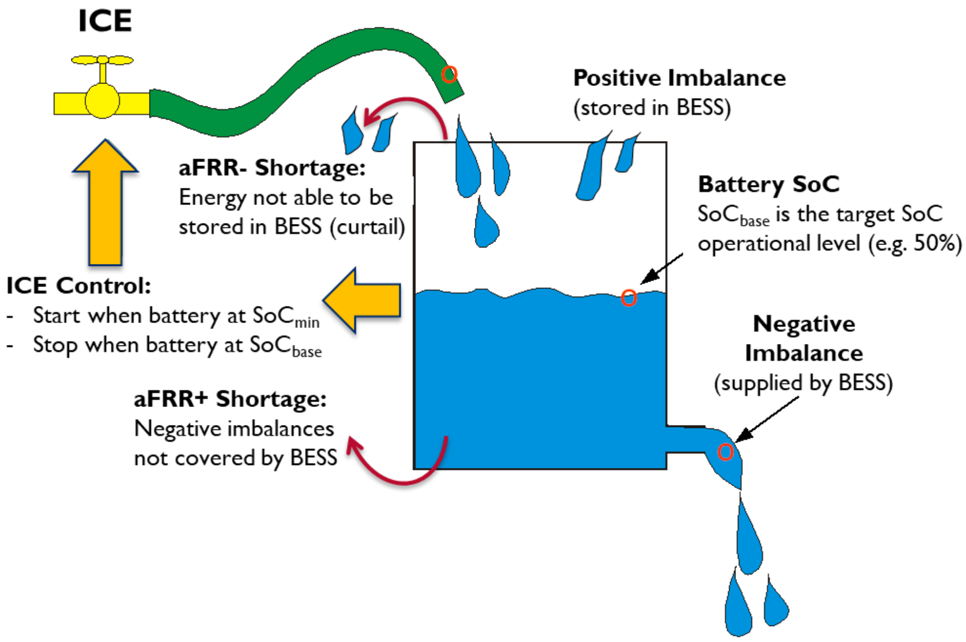


Figure 40 Water analogy for BESS/ICE operation

The key parameter to tuning the operational strategy of the BESS is the state of charge (SoC). For the purpose of this assessment, two levels of BESS SoC were defined: SoC_{min} and SoC_{base} (Figure 40, which shows a water analogy for BESS/ICE utilization). These parameters drive the energy management strategy as follows:

- **BESS follows the system imbalances:** BESS charges during the positive imbalances and discharges during the negative imbalances.
- **ICE follows the BESS SoC:** ICE starts when the BESS reaches a critical level (SoC_{min}) and stops when the BESS reaches the intended base level (SoC_{base}).
- **aFRR+ shortage:** The negative imbalances that are not covered by the BESS/ICE combination are recorded as aFRR+ shortage.
- **Spilled energy:** Any positive imbalances that cannot be stored by the BESS due to lack of free storage capacity are recorded as aFRR− shortage (also referred to as spilled energy). This leads to market signals for any potential private project that would consider energy arbitrage for their business case.

Table 21 Target SoC assumptions for the technical analysis

BESS/ICE Combination	Target SoC_{base} [%]	Target SoC_{min} [%]
1h BESS 2 ICE	50	10
1h BESS 4 ICE	50	10
2h BESS 2 ICE	25	5
2h BESS 4 ICE	25	5
4h BESS 2 ICE	12.5	2.5
4h BESS 4 ICE	12.5	2.5

6.2.3 RESULTS

The results from the technical analysis of the BESS/ICE combinations are shown in Table 22 and Table 23. The shortage of aFRR+ reflects the combined BESS/ICE system's inability to address negative imbalances (lack of upward flexibility) in the system. This occurs in situations of sustained negative imbalances when the battery is depleted and the ICEs cannot cover the remaining imbalances. Conversely, a shortage of aFRR− (lack of downward flexibility) points to insufficient storage capacity for charging the battery using excess positive imbalances. The shortage of aFRR− is considered less important in this analysis, because it is due to a structural over-purchasing of energy by the provider in Moldova, as confirmed by Moldelectrica. This shortage may provide a market signal to alter this strategy.

Table 22 BESS results from BESS/ICE technical analysis

BESS/ICE Combination	aFRR+ Shortage [GWh]	aFRR- Shortage [GWh]	BESS Cycles / year	Mean SOC [%]	Percentage of Time SOC > 50%	Percentage of Time SOC > 30%	BESS Energy Sum [GWh]
1h BESS, 2 ICE	13.4	49.2	1,219	55	51	71	20,699
1h BESS, 4 ICE	-	49.2	1,468	57	50	77	21,713
2h BESS, 2 ICE	12.5	38.0	651	46	40	53	34,490
2h BESS, 4 ICE	-	38.1	761	47	40	52	35,457
4h BESS, 2 ICE	11.3	26.7	349	39	33	46	58,806
4h BESS, 4 ICE	-	26.7	397	39	33	46	59,584

Notably, all combinations featuring two ICE units exhibit a shortage of aFRR+, suggesting a deficiency in backup ICE capacity. This deficiency leads to shortage during periods when the BESS is at a low SoC. Combinations with a one-hour BESS demonstrate the highest frequency of BESS cycling per year, which leads to higher BESS deterioration. Doubling the BESS energy capacity leads to a roughly 50 percent reduction in BESS cycling. Regarding the operation of ICEs, combinations with four ICE units lead to lower average asset utilization but to a doubling of ICE start-ups per year. As all these parameters may affect investment decisions, a financial cost model is necessary to assess the optimal combination. This analysis is presented in Chapter 8.

Table 23 ICE results from BESS/ICE technical analysis

BESS/ICE Combination	ICE Start-ups /year	ICE Generation [GWh]	ICE Utilization [%]	ICE CO_2 Emissions [tons]	ICE Fuel Consumption [GJ]
1h BESS, 2 ICE	729	83	26	37,989	666,475
1h BESS, 4 ICE	1,548	92	15	42,165	739,738
2h BESS, 2 ICE	601	73	23	33,343	584,971
2h BESS, 4 ICE	1,328	82	13	37,267	653,798
4h BESS, 2 ICE	496	63	20	28,745	504,293
4h BESS, 4 ICE	1,133	71	11	32,237	565,565

6.3 CAPACITY CALCULATION OF ASSET FOR mFRR NEEDS

The approach to sizing the asset for mFRR is based on fulfilling the megawatt requirements determined by the probabilistic assessment outlined in Chapter 3. Additionally, the asset's ramping capability is required to meet the mFRR+ activation time criteria, ensuring the delivery of the full required megawatts within 12.5 minutes.

The ICE technology can deliver its maximum megawatt output within five minutes, thereby meeting the mFRR+ requirements. For this technology, an asset with an installed capacity of 172 MW is indicated.

7 DEFINITION OF CONNECTION POINT TO THE TRANSMISSION GRID

This chapter corresponds to Activity 2 of the inception report. The definition of suitable connection point to the transmission grid is done in two main steps.

- Initially, suitable substations for connecting flexibility assets and hosting both the BESS and ICE were selected based on the available MW rating and gas supply.
- Second, a nodal analysis was performed by simulating the deployment of the assets for flexibility in each preselected substation. The analysis studied the capability of Moldova's grid to host the asset's operation. The nodal analysis was performed in PowerFactory and assessed through a contingency analysis to identify potential loading or voltage issues in a critical operational snapshot.

7.1 SUBSTATION PRESELECTION

In the process of integrating flexibility assets, substations were selectively identified based on the following critical criteria: minimizing expansion costs, ensuring sufficient megawatt injection capacity, and assessing gas availability. To ensure that the proposed assets could be connected to the power network grid, this analysis avoided all the regions of the transmission system that are congested because of the high number of issued connection permits. This targeted approach streamlined the nodal analysis by focusing on a smaller, more strategically chosen subset of substations, thereby optimizing operational efficiency and cost-effectiveness, supporting the fast deployment of the new projects.

7.1.1 OBJECTIVE

This section identifies substations within Moldova's power system that can accommodate flexibility assets with the least required modification for substation expansion.

7.1.2 APPROACH

To select the substations, a criterion was created that considers various technical, historical, and commercial factors. This methodology provided a structured and systematic approach to evaluate and rank potential substations based on their suitability for the task. The approach was divided into two steps.

7.1.2.1 INITIAL SCANNING OF SUBSTATION DATA

The initial scanning of substation data for selection involved a comprehensive evaluation based on various criteria. Proximity of the asset is a foundational consideration, emphasizing the importance of minimizing transmission distances to enhance overall efficiency and reduce energy losses. Historical data analysis, including factors such as floods and area constraints, is imperative to assess potential risks to the reliability of the assets. Adequate space provision is crucial for bay extension and control panel installation, ensuring seamless modifications without significant alterations. Technical criteria, encompassing bus ampere rating, structural integrity, control enclosure space, protection equipment, short-circuit level, auxiliaries, earthing, lightning protection, and compatibility with SCADA and the fault management system, form essential parameters for substation viability. Furthermore, commercial considerations, such as the avoidance of soil filling and earth removal, were factored in to ensure cost and time efficiency. This initial scanning process aided in the selection of substations that align with the required specifications for successful integration. Considering their size, to ensure a feasible connection, all the new assets will be connected at the 110 kV level with the grid.

Based on the initial scanning of substation data, the following substations were identified for connection:

- For battery assets: Preliminary analysis indicates that the BESS capacity for FCR and aFRR can be accommodated in Straseni, Hancesti, and Vulcanesti substations. The selection of the suitable substation, detailed in the following section, is based on the available capacity of these three substations. It's important to note that the final decision will be made for only one substation.
- For fast thermal assets: As per the initial scan, for the fast thermal capacity/mFRR, more consideration was given to substations near gas hubs with sufficient gas availability. Balti, Rezina, Orhei, Comrat, Floresti, Cahul, Gura Galbenei (Cimislia), Ungheni, and Glodeni were considered.

Table 24 Substation data

Place / Point Name	Total capacity (m^3/24 hours)	Available capacity (m^3/24 hours) (capacity for 12 bar grids)	ICE capacity (MW)	Near Substation	Disposable capacity (MW)
Balti	1,200,000	497,150	94	Balti	318
Rezina	1,680,000	1,561,131	295	Rezina	48
Orhei	1,680,000	1,568,496	297	Orhei	74
Comrat	1,680,000	1,506,584	NA	Comrat	
Floresti	1,680,000	1,613,918	305	Floresti	117
Cahul	840,000	677,771	NA	Cahul	
Gura Galbenei (Cimislia)	712,000	216,950	41	Gura Galbenei	70
Ungheni	669,000				
Glodeni	1,680,000	1,281,746	242	Glodeni	84

7.1.2.2 IDENTIFICATION OF SUBSTATION WITH RESPECT TO DISPOSABLE CAPACITY

After Moldelectrica provided the available data for substation selection, following a comprehensive review and detailed discussions with the Moldelectrica team, the following key takeaways were identified:

- **Substations for BESS assets:** Straseni, Hancesti, and Vulcanesti are the substations that are suitable for BESS assets. These substations are centrally located and have the capacity for bay extension.
- **Substations for fast thermal assets:** Floresti, Orhei, and Balti substations are situated in outlying areas, are in close proximity to gas pipelines, and can be used for ICE connection.
- **Technology:** All the substations in Moldova are air-insulated.

- **General suitability of other substations:** Apart from Straseni, Hancesti, Vulcanesti, Floresti, Orhei, and Balti, the other substations are not suitable for the connection of any type of asset. Therefore, it was agreed to consider only the above six substations.

Substations were ranked for connecting BESS assets as follows:

1. Straseni
   - Transformers have 200 MVA and 110, 35, and 10 kV.
   - Primary equipment, circuit breakers, SF6, and transfer buses are new. The construction structure is still in the initial stage.
   - The substation has the possibility for bus bar extensions; three spare bases are also available for extensions.
   - The existing SCADA system has reserve capacity and can integrate with the alarms of new bays.

2. Hancesti
   - The substation has the possibility for bus bar and other extensions.
   - Primary equipment, circuit breakers, SF6, and transfer bus bars are new. The construction structure is still in the initial status.
   - The protection and automation system has been updated.

3. Vulcanesti
   - The substation is located in a rural area of Moldova.
   - The substation has the possibility for bus bar and other extensions.
   - Primary equipment, circuit breakers, SF6, and transfer buses are new on the 110 kV side. The construction structure is still in the initial status. The 400 kV side is in reconstruction.
   - Possibility to fit and/or extend one new bus bay.

Following the initial scan of available substations, the shortlisting process was based on modeling results, specifically focusing on the capacity of each asset class.

For BESS, considering a capacity requirement of 77 MW (72+5), inclusive of FCR and aFRR, the Straseni substation emerges as the sole location with sufficient disposable capacity to accommodate this asset. Other salient features of the Straseni substation that make it the most suitable location for the placement of BESS are:

- It is near the load.
- It is equipped with stable and modern equipment, resulting in lower system integration costs for the BESS.
- An additional bay is available for new switching equipment for the BESS.

Fast thermal assets with a capacity of 180 MW are distributed across three substations: Balti, Orhei, and Floresti. Additionally, Glodeni and Gura Galbenei (Cimislia) stand as potential options based on gas availability at the nearest gas hub locations. Table 25 illustrates the accommodation capacities of each substation concerning the gas supply, providing a clear framework for shortlisting the most suitable substations for fast thermal asset deployment.

Table 25 Substation data with respect to available capacity

Point Name	Available capacity (in m^3/24 hours) (capacity for 12 bar grids)	Available capacity (in m^3/hr) – for 12 bar grids (Q)	Power generation potential from ICE = Q/0.22 KW	Near substation	Disposable capacity (MW)
Balti	497,150	20,715	94,159	Balti	318
Rezina	1,561,131	65,047	295,668	Rezina	48
Orhei	1,568,496	65,354	297,064	Orhei	74
Comrat	1,506,584	62,774	NA	Comrat	Nil
Floresti	1,613,918	67,247	305,668	Floresti	117
Cahul	677,771	28,240	NA	Cahul	Nil
Gura Galbenei (Cimislia)	216,950	9,040	41,090	Gura Galbenei	70
Ungheni					
Glodeni	1,281,746	53,406	242,754	Glodeni	84

7.1.3 RESULTS

The Straseni substation emerges as the preferred location for deploying the BESS asset, which boasts a total capacity of 72 MW + 5 MW and is adept at managing both FCR and aFRR requirements. For the ICE infrastructure required for aFRR+ support, the Glodeni substation is preliminarily chosen to accommodate 72 MW. Alternatively, in a different configuration, this 72 MW capacity can be distributed among Floresti (36 MW), Orhei (18 MW), and Balti (18 MW).

For the fast thermal asset with 180 MW capacity, utilizing ICE for mFRR, the Balti, Orhei, and Floresti locations are under consideration. At each of these locations, a capacity of 60 MW has been allocated.

7.2 NODAL ANALYSIS FOR SUITABILITY OF CONNECTION POINTS

This section corresponds to Activity 2.3 and 3.1.2 of the inception report.

7.2.1 CRITICAL SNAPSHOT SELECTION

The variability of RES production paired with different consumption levels and production from conventional sources leads to large variation in power flows. Therefore, it is prudent to consider system operating conditions with due consideration to not only the load magnitude but also the amount of RES generation, and in the Moldovan case, also the flow produced by neighboring countries.

7.2.1.1 OBJECTIVE

The objective of this section is to select the critical operation conditions (snapshots) from the zonal dispatch to be analyzed in the nodal model.

7.2.1.2 APPROACH

The critical snapshots were found by analyzing the results of the zonal dispatch during maximum load condition in Moldova, high flow from Romania to Ukraine, and high variable RES generation under the conditions of minimum daily load in Moldova. These critical conditions were agreed with Moldelectrica based on their expertise.

7.2.1.3 RESULTS

To determine the range of system conditions encompassed in the selected snapshots, a method utilizing state-space analysis was employed. This approach, as shown in Figure 41, demonstrates the load of individual states within the network as a percentage of peak demand, and the contribution of non-synchronous generation to the total system load defines the snapshot selection space.

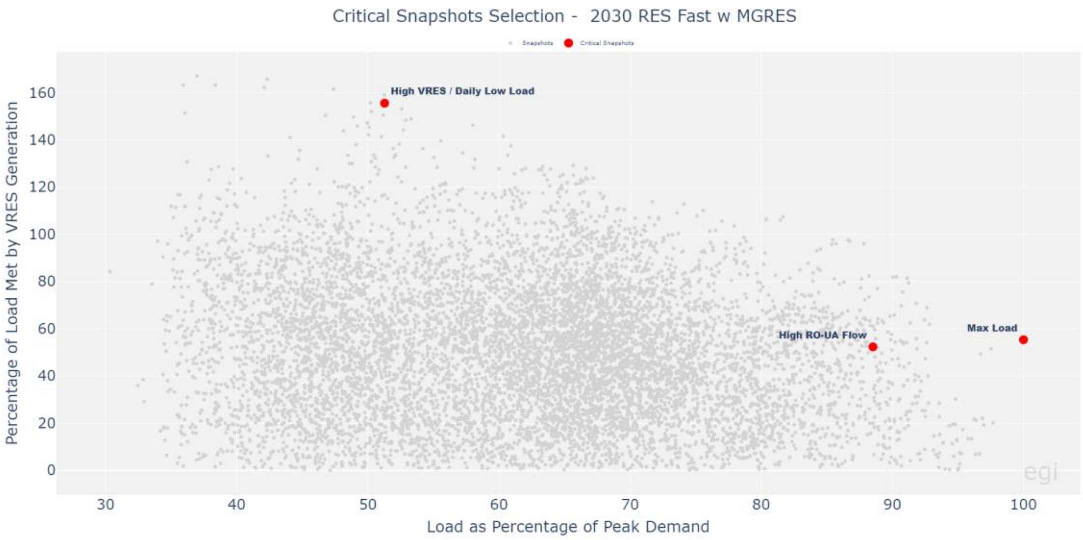


Figure 41 Critical snapshot selection – 2030 Fast with MGRES

The scenario considered for the nodal analysis was 2030 Fast with MGRES, which depicts the maximum level of installed RES capacity and thus its generation. Figure 42shows that the selected scenario encompasses the most critical operational conditions, in red, compared to the other scenarios' critical snapshots, in orange.

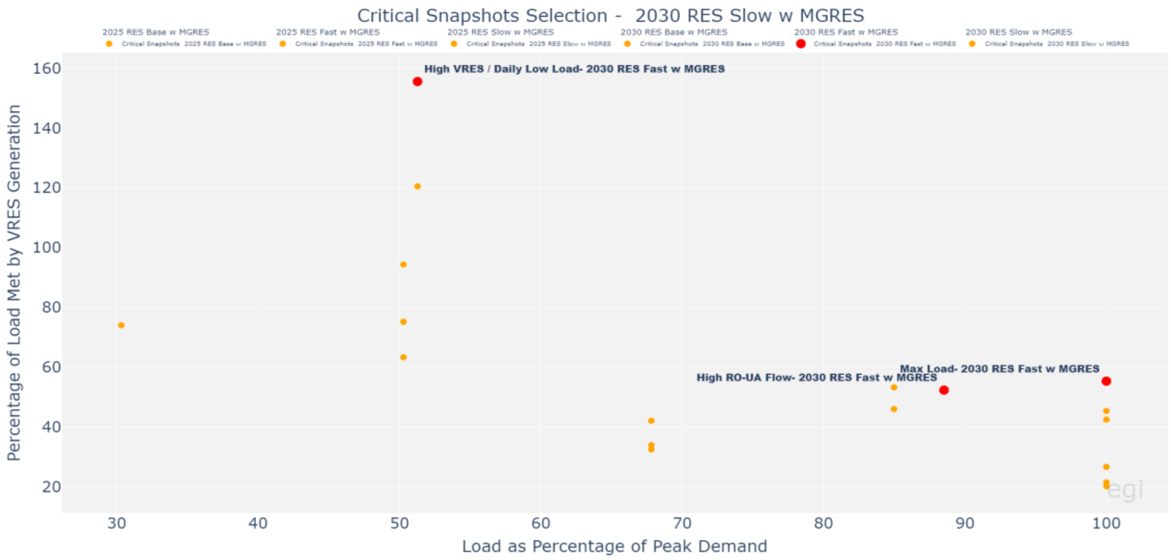


Figure 42 Critical snapshot selection – 2030 Slow with MGRES

7.2.2 NODAL ANALYSIS

7.2.2.1 OBJECTIVE

The main objective of the nodal analysis in PowerFactory was to assess the grid impact (in terms of loading and voltages) that the installation of additional assets (ICEs and BESS) might introduce into the grid based on specific critical snapshots that result from the zonal process and to propose alternative points of grid connection in case of loading or voltage deviations.

An additional objective was to assess the short-circuit ratio (SCR) in the point of connection where the BESS would potentially be installed.

7.2.2.2 APPROACH

The nodal analysis approach encompassed the assumptions made for the nodal model, as agreed with Moldelectrica. It included the analyzed configurations and the specific analyses carried out for each configuration.

To perform the nodal analysis, certain assumptions were considered and agreed upon, as follows.

Base Power Factory Model

- Moldelectrica provided and agreed on the PowerFactory snapshot that will be used as a base to accommodate the critical scenarios to be analyzed.
    - The provided PowerFactory model contains only a “reduced” part of Ukraine due to privacy concerns. The reduction was performed on Moldelectrica’s side.
- The PowerFactory model is assumed to contain all the infrastructural changes associated with the target year of analysis.
    - The Balti-Suceava Interconnection was considered for 2030 scenarios.
    - Controller settings of the generation units remained unchanged.
- Alternating current (AC) voltage sources (represented as extended wards) in Ukraine remained unchanged after following the patterns observed in the two original snapshots provided by Moldelectrica.
- Slack bus is present in an external grid.
- It was assumed that the initial starting grid was already provided as dynamically stable.

Distribution of Load and Generation for each Critical Scenario

The following approach was executed to distribute the load and the generation according to the dispatch points of the critical scenarios. However, considering that every dispatch point could have different behavior in terms of convergence (mainly due to reactive power/voltage limitations), certain deviations in the process needed additional adaptations/considerations inherent to each individual case.

- Generation in Moldova for each analyzed scenario was set at a unit level based on the initial PowerFactory model provided by Moldelectrica.
- Load in Moldova was distributed pro-rata based on the “on service” total load present in the initial model.
- In the case of the “reduced Ukraine” and Romania, the pro-rata distribution was performed based on the “on service” total generation and load present in the model (the Base snapshot referred to as Case 1 below) for each instance of Ukraine and Romania (as not all the power

plants in Romania and Ukraine show a technology type, and the study team did not have access to the units and loads for all of Ukraine in the PowerFactory model).

- In the case of "reduced Ukraine," a fixed factor was considered based on a linear relation between total installed capacity in Ukraine and the total installed capacity inside "reduced Ukraine." A similar approach was used for the load. Such a relation was deduced from the Base scenario. This factor is relevant because PLEXOS showed results for all of Ukraine, and they needed to be scaled to the "reduced Ukraine" version from the PowerFactory model.

Critical snapshots

1. **High Flow, Southeast Romania to Ukraine**
2. **High Variable Renewable Energy Sources (VRES)/Low Load (daily)**
3. **Maximum Load**

Analyzed configurations

For the critical snapshots, the following configurations were analyzed in the nodal model:

1. **Case 1 – Base critical snapshot:** implementation of the load and generation dispatch of the snapshot in the grid model
2. **Case 2 – Base critical snapshot + BESS:** actual dispatch and injection from the BESS unit at full rated capacity
3. **Case 3 – Base critical snapshot + one ICE unit:** actual dispatch and injection from one ICE unit at rated capacity
4. **Case 4 – Base critical snapshot + multiple ICE units:** actual dispatch and injection from multiple ICE units at rated capacity
5. **Case 5 – Base critical snapshot + multiple ICE units (high):** actual dispatch and injection from multiple ICE units at rated capacity with additional units in comparison to case 4
6. **Case 6 – Base critical snapshot + additional configurations** needed in case of issues with the initially proposed connection point

Analyses performed

Three main analyses were performed for each configuration:

1. **Load flow**

Load flow analyses produce a general overview of loading and voltages in the "N state" of the grid. This was performed for the critical snapshot and a map of country flows depicted. This analysis is inherent for the case 1 as the "base" where additional assets were analyzed. This case allowed the team to understand whether the addition of the assets would cause specific issues in the respective critical snapshot.

2. **N-1 contingency analysis**

This analysis provided outcomes in terms of loading and voltages for all the proposed configurations.

The thresholds considered for the N-1 contingency analysis were as follows:

- Loading limit for lines and transformers: 100 percent

- Maximum voltage threshold: 1.1 p.u. for <400 kV and 1.05 for 400 kV
- Minimum voltage threshold: 0.9 p.u. for <400 kV and 0.95 for 400 kV

The main outcome of this section is a report on the potential critical assets that would become overloaded (or experience voltage violation) in Moldova and propose potential solutions in such "steady state" cases related to alternative locations for the grid connection of the additional assets under discussion.

The contingency analysis N-1 is intended for all the analyzed configurations.

3. Short-circuit ratio assessment

SCR is a metric to assess system strength in a specific point of connection. It is calculated as follows:

$$SCR = S_{(SC-MVA)}/P_{(BESS-MW)}$$

In this case, SCR was used to identify a robust enough point of connection to connect the BESS. In the case of a low SCR, an additional connection point would be proposed.

This assessment was only used on case 2, related to BESS installation.

This is an indicative/approximate number, as there are already implicit assumptions (especially the grid reductions intended for other the operating scenario) that prevents a more accurate number. However, an SCR of 5 is considered a threshold for potential risk, so any number above that is considered high enough.

7.2.2.3 RESULTS

Critical snapshot: High Flow, Southeast Romania to Ukraine

This critical snapshot is of primary interest for Moldelectrica, considering its potential to lead to loop flows across Romania-Moldova-Ukraine. Therefore, it was the focus of this report and features more detailed results. The following configurations were analyzed for this critical snapshot:

Table 26 Asset configurations

Case	Assets	Location and power injection	Voltage level
Case 1	No additional	-	-
Case 2	BESS	Straseni (77 MW)	110 kV
Case 3	1 ICE	Glodeni (72 MW)	110 kV
Case 4	Multiple ICEs	Balti (60 MW), Ohrei (60 MW), Floresti (60 MW)	110 kV
Case 5	Multiple ICEs (High)	Balti (60 MW), Ohrei (60 MW), Floresti (60 MW), Glodeni (72 MW)	110 kV
Case 6 (alternative option)	Multiple ICEs (High)	Balti (78 MW), Ohrei (78 MW), Floresti (96 MW)	110 kV

Figure 43 AC load flow Case 1 – critical snapshot, high flows RO-UA – active power flows overview

The following tables show the highest loading and voltage deviations in the N state. There are no violations before the installation of the assets.

Table 27 Three highest loadings for the N state, voltage levels 110, 330, and 400 kV, case 1 – critical snapshot high flows RO-UA

Line name	Voltage level	Loading in N state
lne_63509_636038_1(Vulcanesti MD – Bolgrad UA)	110 kV	**71.77%**
lne_630110_634063_2 (CTE Moldoveniasca)	110 kV	**70.11%**
lne_630110_637040_1 (CTE Moldoveniasca)	110 kV	**62.9%**
lne_63803_630100_1 (CTE Moldoveniasca MD – Novoodeska UA)	330 kV	**41.65%**
lne_63802_630100_1 (CTE Moldoveniasca MD – Usatove UA)	330 kV	**30.49%**
lne_63806_630100_1 (CTE Moldoveniasca MD – Podilska UA)	330 kV	**14.62%**
lne_44121_636046_a (Vulcanesti)	400 kV	**36.47%**
lne_44121_636046_1 (Vulcanesti MD – Isaccea RO)	400 kV	**36.14%**
lne_Vulcanesti-Chisinau (Vulcanesti-Chisinau)	400 kV	**17.02%**

The main voltage deviations before the installation of the assets can be observed in the following table (no violations as per the applied thresholds).

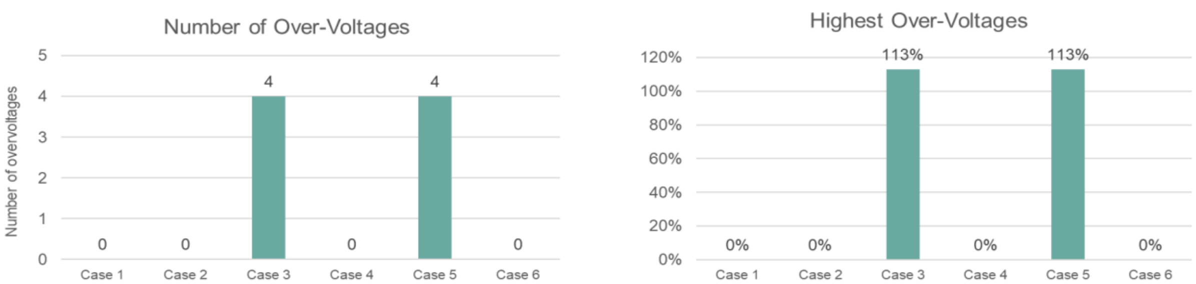
Table 28 Three highest voltages in the N state for 110, 300, and 400 kV, case 1 – critical snapshot high flows RO-UA

Line name	Substation	Voltage level	Voltage results (p.u.) in N state
633038 5RIBNI53	Ribnita	110 kV	**1.06**
632029 5TSEMZ51	F-ca de ciment	110 kV	**1.06**
633014 5 MMZ3451	MMZ	110 kV	**1.06**
BB-Dn.	Balti	330 kV	**1.03**
BB-1AT	Balti	330 kV	**1.03**
BB-Dn.	Balti	330 kV	**1.03**
Terminal (2)	Chisinau	400 kV	**1.03**
Terminal	Chisinau	400 kV	**1.01**
1BB 400 kV	Vulcanesti	400 kV	**1.00**

<u>Contingency analysis – High flows from Romania to Ukraine</u>

No loading violations were observed for any of the analyzed configurations under the critical snapshot. However, slight voltage violations were observed for cases 3 and 5 related to the installation of the ICE in Glodeni 110 kV.

An overview of over-voltage violations in this critical snapshot (high flows from Romania to Ukraine) can be observed in Figure 44. Due to over-voltages in the two configurations where the ICE is installed in Glodeni 110 kV, a new location is proposed instead of Glodeni (case 6). In this reconfiguration, the



72 MW are redistributed into Balti (18 MW), Orhei (18 MW), and Floresti (36 MW).

Figure 44 Voltage violations in Moldova for the critical snapshot: High Flows RO-UA, over-voltages per configuration (left) and over-voltage peaks (right) for 110 kV and above

In cases 3 and 5, four instances of over-voltage are observed at the following substations: Glodeni, Sturzesti, and Camencuta (twice) at the 110 kV level. These are primarily attributed to the status of the “lne_632007_632023_1” line, which connects Glodeni and Sturzesti at the 110 kV level and is found to be in the “off” state.

In general, there are no instances of under-voltage violations. The only configurations where results approach the limit of 0.9 per unit (p.u.) are observed in cases 5 and 6. These particular bus bars are situated at the following substations: Falesti, Falesti-TUM, and ZTUM2, all operating at the 110 kV level. The primary factor contributing to these lower voltages is the contingency involving the Balti-Falesti 110 kV line.

This analysis modeled the additional assets (ICEs and BESS) solely from an active power perspective, without incorporating a voltage support scheme, to assess the impact on steady-state voltages and loading conditions within the Moldova grid. Consequently, it is plausible that even in cases where there are minor voltage deviations, particularly in cases 3 and 5 where ICEs are installed at the Glodeni 110 kV substation, no voltage violations may occur when an appropriate voltage control mechanism is implemented in accordance with operator agreements and specific operational parameters.

SCR Assessment - High Flows from Romania to Ukraine

According to the SCR criteria application and under the explained conditions and specific operation scenario, the selected connection point (Straseni 110 kV) is strong enough to connect the BESS with a SCR of about 40 in an N-1 situation.

Critical snapshot: High VRES/Low Load (daily)

This critical snapshot is also of significant interest to Moldelectrica, as it represents a potential case with high internal flows. The following configurations were analyzed for this critical snapshot:

Table 29 Asset configurations

Cases	Assets	Location and Power Injection	Voltage level
Case 1	No additional	-	-
Case 2	BESS	Straseni (77 MW)	110 kV
Case 3	1 ICE	Glodeni (72 MW)	110 kV
Case 4	Multiple ICEs	Balti (60 MW), Ohrei (60 MW), Floresti (60 MW)	110 kV
Case 5	Multiple ICEs (High)	Balti (60 MW), Ohrei (60 MW), Floresti (60 MW), Glodeni(72 MW)	110 kV

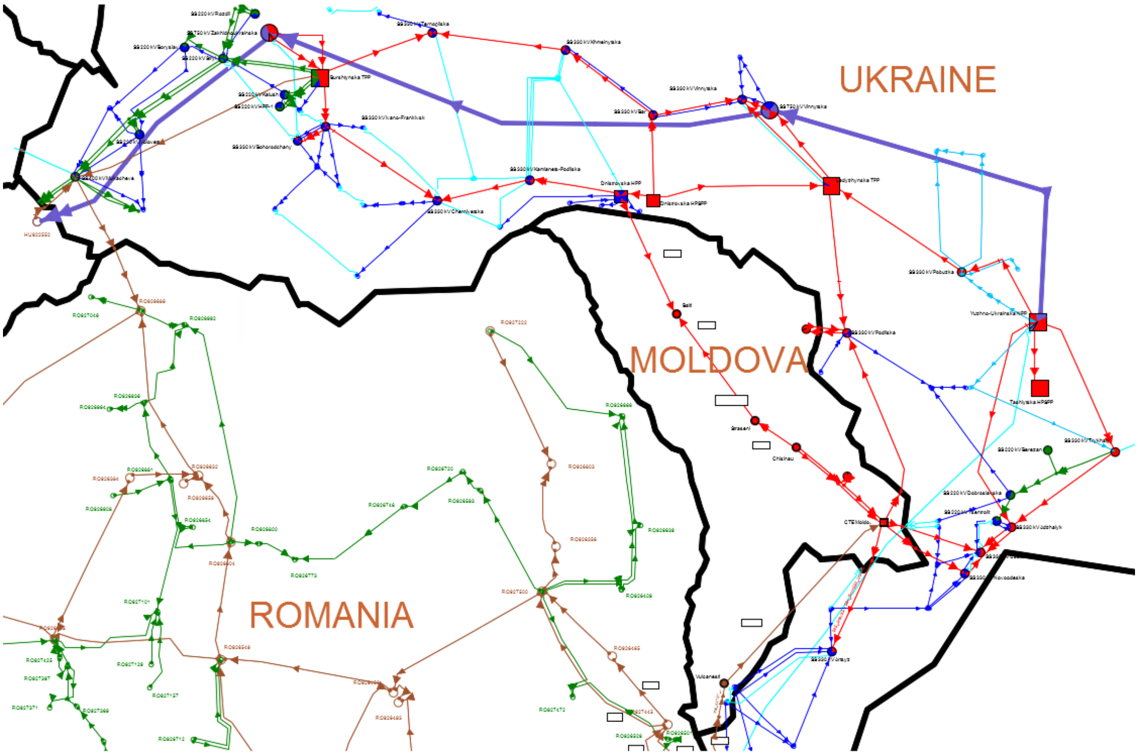


Figure 45 AC Load flow Case 1 – Critical snapshot: High VRES/Low Load (daily) – active power flows overview

Similar to the previous critical snapshot, no overloading or voltage deviation violations were recorded in Moldova in case 1 of this critical scenario after performing a load flow analysis (N state).

<u>Contingency analysis – High VRES/Low Load (daily)</u>

This snapshot might include overloading and slight over-voltage in case 1 (when the dispatch point is "accommodated" into the grid), mainly driven by the contingencies Chisinau–Hancesti 110 kV, Balti–Sturzesti 110 kV, and Vulcanesti–Isaccea 400 kV.

After the introduction of the BESS and ICEs in their respective proposed points of connection, no additional relevant violations were registered (apart from those in case 1). This is relevant because the analysis focused on the potential additional violations driven by the assets and not on proposing a specific redispatch or voltage control scheme for each individual operational scenario represented in the case 1 of each critical snapshot.

Regardless, and as part of future works, further analyses are recommended on operational security for operating the grid under such an extreme snapshot driven by high penetration of renewables and low load. Moldelectrica should consider these overloadings when issuing connection permits for this part of the network and in further long-term planning exercises.

<u>SCR Assessment - High VRES/Low Load (daily)</u>

Similar to the previous critical snapshot, the selected connection point (Straseni 110 kV) is strong enough to connect the BESS, with a SCR of about 40 in an N-1 situation.

Maximum Load

This snapshot was also agreed upon with Moldelectrica to account for scenarios with high load. Similar to the previous critical scenario, the following configurations were considered:

Table 30 Asset configurations

Cases	Assets	Location and power injection	Voltage level
Case 1	No additional	-	-
Case 2	BESS	Straseni (77 MW)	110 kV
Case 3	1 ICE	Glodeni (72 MW)	110 kV
Case 4	Multiple ICEs	Balti (60 MW), Ohrei (60 MW), Floresti (60 MW)	110 kV
Case 5	Multiple ICEs (High)	Balti (60 MW), Ohrei (60 MW), Floresti (60 MW), Glodeni(72 MW)	110 kV

Figure 46 AC Load flow Case 1 – Critical scenario: Maximum Load – active power flows overview

Consistent with previous critical scenarios, there were no instances of overload or voltage deviation violations observed in Moldova for case 1 of this particular critical scenario following a load flow analysis (N state).

Contingency analysis – Maximum Load

In the event of this critical scenario (case 1), there would be a potential overloading in the transformer at MGRES driven by the contingency at 520_YUUAES-3 -- 523_Adzhalyk3 330 kV, but no relevant voltage deviations were recorded in Moldova.

Similar to previous critical scenarios, the installation of critical assets would not lead to additional deviations, which would be already present in the base case I. In line with the conclusions from the case of high flows from Romania to Ukraine, Balti, Orhei, and Floresti 110 kV would have priority over Glodeni 110 kV when it comes to the installation of the ICE assets.

SCR Assessment – Maximum Load

Similar to the previous critical scenario, the selected connection point (Straseni 110 kV) is strong enough for the connection of the BESS.

7.3 CONCLUSION

According to these snapshots, introducing ICES and BESS in the suggested locations would not cause relevant violations in loading or voltages in the N-1 situation. In principle, Straseni can properly accommodate the installation of the intended BESS, whereas Balti, Orhei, and Floresti can accommodate the ICEs. Straseni 110 kV also appears to be a robust enough connection point for BESS installation in terms of SCR.

Regardless of the evolution of these new flexible assets, the network analysis identified some potential operating regimes of the existing transmission network that should be monitored by Moldelectrica. Considering that the analyses were performed under specific assumptions and specific boundaries set by the project, further security analyses should take into consideration specific N-1-1 situations that can be conducted by Moldelectrica based on their experience and operational procedures. This is mainly due to the scenario with high VRES and low load (daily), in which potential issues were registered in Moldova for the base case, especially driven by the contingency Vulcanesti–Isaccea 400 kV. This contingency is also likely to cause issues in other scenarios.

8 TOTAL PROJECT COST ESTIMATION

This chapter corresponds to Activity 3.4 and 5.3 according to the inception report. It breaks down the costs associated with the BESS and ICE technologies selected for FCR, aFRR, and mFRR. Additionally, for the aFRR asset combinations, it provides a financial analysis of the various technically viable solutions studied in section 7.2.

8.1 FCR AND aFRR BESS ASSET COSTS

This section provides the cost estimation for BESS. It includes basic cost estimates, with the general costs considered for each asset type detailed in Table 31.

Table 31 Cost estimate components

Costs	Detail
Design	Expenses related to the engineering and design of fast thermal and BESS assets.
Supply	Cost associated with procuring the necessary equipment and materials for the projects.
Logistic	Expenses for transporting equipment and materials to the project site.
Installation	Costs involved in the physical installation of fast thermal and BESS assets.
Testing and commissioning	Expenses incurred during the testing and commissioning phase to ensure the assets function as intended.
Civil engineer	Costs related to civil engineering work, such as foundation construction and structural elements.
Mechanical balance of plant	Expenses associated with the non-electrical systems and components necessary for the operation of the power plant.
Generation side substation equipment	Cost of equipment for the substation on the generation side of the project.
Substation renovation and modernization	Expenses for upgrading and modernizing the grid substation, if required.

Table 32 presents a detailed breakdown of the CAPEX for BESS across the three configurations analyzed in Chapter 7 and the FCR requirements for one-hour BESS of 5 MW. These costs are based on the team's industry knowledge and on similar (confidential) projects in Western Europe. They are also in line with Bloomberg NEF costs for a fully installed large four-hour AC energy storage system.

Important disclaimer: Considering that these costs are based on projects in markets outside Moldova, there is no guarantee that the result of a tender in Moldova would deliver the same price levels. If a maximum budget has to be estimated, it would be recommended to account for an additional error margin.

Table 32 Estimated project cost for BESS

		72 MW One-hour	72 MW Two-hour	72 MW Four-hour	5 MW One-hour
Supply (including transport)	Battery (Direct Current scope)	23,760,000	47,520,000	95,040,000	4,400,000
	PCS	4,400,000	4,400,000	4,400,000	814,815
	Medium-voltage transformers	2,750,000	2,750,000	2,750,000	509,259
	Medium-voltage cables and protections	880,000	880,000	880,000	162,963
	High-voltage transformer	2,200,000	2,200,000	2,200,000	407,407
	High-voltage cables and protections	3,300,000	3,300,000	3,300,000	611,111
	Existing substation modification	1,650,000	1,650,000	1,650,000	305,556
Installation and commissioning		2,420,000	3,850,000	5,500,000	448,148
Civil works		4,400,000	6,600,000	9,900,000	814,815
Project management		1,650,000	1,650,000	1,650,000	305,556
Total		**47,410,000**	**74,800,000**	**127,270,000**	**8,779,630**

8.2 aFRR AND mFRR ICE ASSET COSTS

Considering the capacity needed outlined in section 6.3 to meet mFRR requirements, total installed capacity of 172 MW is necessary. Building upon the findings of the market analysis in section 5.3.2, it is apparent that the actual asset capacity can be met by deploying ten ICE units, resulting in a total installed capacity of 180 MW. Furthermore, it is considered a best practice to incorporate a backup unit to ensure uninterrupted availability during maintenance periods. This leads to a total needed capacity of 198 MW, for 11 units.

For aFRR requirements, a total of four units with installed capacity of 72 MW is proposed, based on the results of the financial model.

Accordingly, the total cost breakdown for ICE assets for flexible generation capacity of 198 MW (mFRR) and 72 MW (aFRR) is presented below Table 33.

Table 33 Cost breakdown and total cost estimate for 198 MW/11 units (mFRR) and 72 MW/4 units (aFRR)

Description	Per MW ($)	For 198 MW, mFRR ($)	For 72 MW, aFRR ($)
Machine cost	605,000	119,790,000	43,560,000
Land and site development cost (25% of CAPEX)	151,250	29,947,500	10,890,000
Balance of plant, including mechanical and electrical equipment at generator side (25% of CAPEX)	151,250	29,947,500	10,890,000
Overhead line from generating station to grid station	90,750	17,968,500	6,534,000
Grid substation modification	18,150	3,593,700	1,306,800
Gas pipelines, compressor, water lines, etc.			
Approximately 10% of capital cost			
Preliminary and pre-operative expenses (2% of capital cost)			
Contingency cost (5% of total cost)	50,820	10,062,360	3,659,040
Total cost (excluding taxes, duties, transportation, etc.)	**1,067,220**	**211,309,560**	**76,839,840**

These are initial cost estimates for BESS and fast thermal assets. The source of the ICE machine cost is the OEM's indicative price, and the other costs were derived by rule of thumb. The final estimates will be provided after the bill of quantities is final.

Assumptions for initial cost estimates:

- The cost estimates are based on the current project scope.
- The cost estimates reported in Table 33 were prepared considering a frame size of 18 MW, (excluding BOP), which puts an indicative consideration of the price per 18 MW unit at $10.86 million, ex works (i.e., $606,000/MW). It will be used for an internal understanding of the cost only. However, to maximize vendor participation, frame sizes in the range of 10 MW and above may be accepted. Accordingly, there will be a minor change in overall capacity depending upon the frame size.
- The site development, land charges, 110 KV overhead line, gas pipeline, and water line costs have been estimated based on rule of thumb. The estimates can only be optimized after the actual site for the asset is identified.
- The cost of the approach road is not included in the above estimations.

8.3 aFRR ASSET FINANCIAL ANALYSIS

This section reports the total costs for each BESS/ICE configuration that complies with the aFRR requirements, with a focus on the costs relevant to the specific scope and purpose of these configurations. It also presents the results of the financial model developed for the analysis. The analysis provides a clear picture of the configuration's economic viability and the implications in terms of CAPEX and OPEX.

The various assumptions for the financial model are presented in Table 34. The discount rate used within the financial model corresponds to Moldova's country risk premium. The financial model utilizes the CAPEX calculations for BESS in Table 32 and ICE in Table 33.

Table 34 Assumptions for financial model

Parameter	Assumption
Discount rate	9.5%[28]
CAPEX period	1 year
Operational lifetime	10 years
Value of reserve shortage	$1,000/ MWh

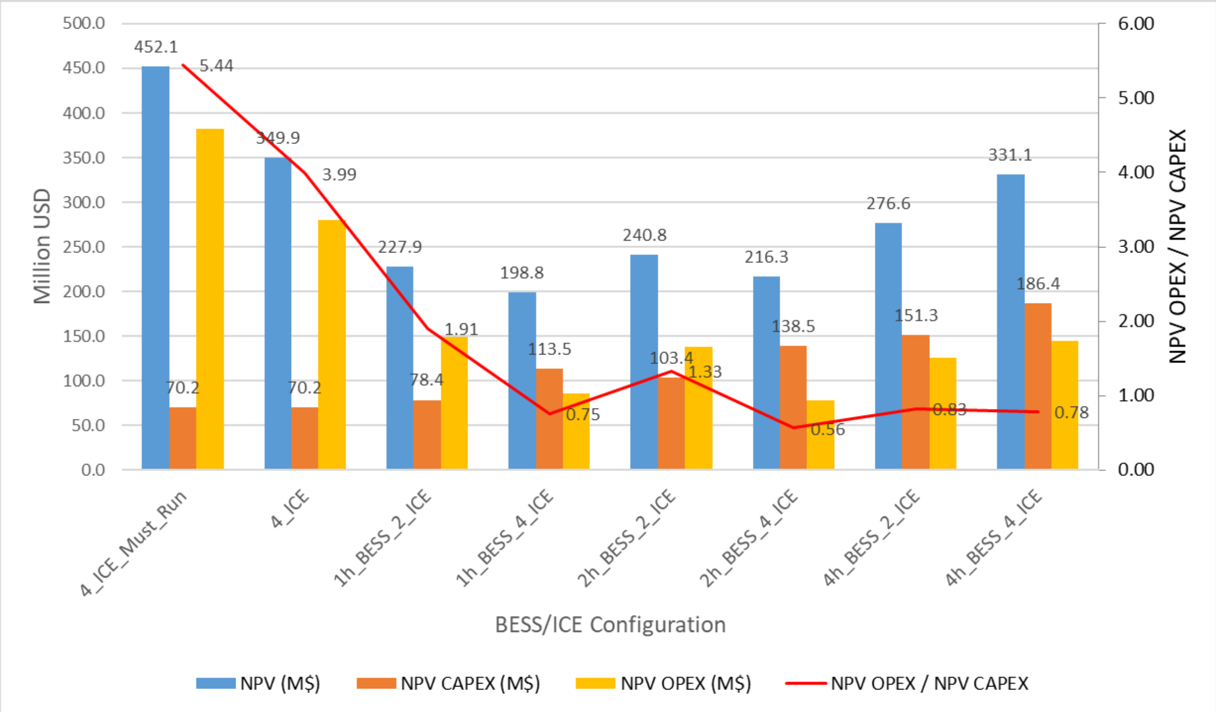


Figure 47 NPV indicators from asset cost analysis

The results of the financial analysis are displayed in Figure 47 and Table 35, which detail the cost estimate components. In Figure 47, the blue bars represent the NPV of the BESS/ICE configurations. Meanwhile, the orange and yellow bars illustrate the NPVs of the CAPEX and OPEX. A red line shows the ratio between the NPV of OPEX and the NPV of CAPEX for each configuration. When this ratio exceeds 1, it indicates that the OPEX is projected to surpass the initial CAPEX throughout the asset's lifetime.

[28] Damodaran, 2024.

This financial model exclusively considers cost components. As a result, this study prioritizes BESS/ICE configurations with lower NPV values, as they imply more cost-effective options in this analysis. The key results show that there are two main candidate configurations:

- One-hour BESS and four ICEs: NPV $198.8 million
- Two-hour BESS and four ICEs: NPV $216.3 million

In assessing the financial viability of battery storage options, a comparative analysis reveals distinct trade-offs between one-hour and two-hour battery systems. The one-hour battery option presents a lower CAPEX and a more favorable NPV, indicating its financial attractiveness. However, several critical factors must be considered. Firstly, the one-hour battery's higher operational cycles (1,500 cycles per year, compared to 700 for the two-hour battery) necessitate verification with manufacturers, as this exceeds the standard guaranteed range of 500 to 1,000 cycles per year. Additionally, market trends show a preference for two-hour or larger BESS capacities, potentially limiting the competitiveness of bids for a one-hour system. For instance, major providers like Tesla do not offer one-hour systems, which could influence the bid landscape.

Furthermore, the model assumes annual additions of battery cells to maintain capacity, whereas practical implementations may extend this to every two or three years, impacting available capacity. A two-hour battery also offers more operational margin, especially during the maintenance periods of BESS or ICEs. Moreover, the automatic start-up capability of the ICE by the automatic generation control is a critical assumption for the five-minute ramp-up hypothesis; any deviation from this would necessitate reconsidering the battery size.

Table 35 Results of asset cost analysis

BESS/ICE Combination	NPV ($, million)	NPV CAPEX ($, million)	NPV OPEX ($, million)	NPV OPEX / NPV CAPEX	aFRR+ Shortage Costs ($, million/ year)	BESS cycles /year
4 ICE Must Run	452.1	70.2	381.9	5.44	-	-
4 ICE	349.9	70.2	279.8	3.99	20.3	-
1h BESS 2 ICE	227.9	78.4	149.5	1.91	13.4	1219
1h BESS 4 ICE	198.8	113.5	85.3	0.75	-	1468
2h BESS 2 ICE	240.8	103.4	137.4	1.33	12.5	651
2h BESS 4 ICE	216.3	138.5	77.8	0.56	-	761
4h BESS 2 ICE	276.6	151.3	125.2	0.83	11.3	349
4h BESS 4 ICE	331.1	186.4	144.7	0.78	-	397

When evaluating the project from a long-term cost perspective related to the assets, a detailed assessment of both NPV and OPEX is crucial. The focus extends beyond total NPV, encompassing CAPEX and emphasizing the significance of NPV OPEX over a ten-year period. This measure is key in assessing long-term financial implications for the asset operator. The configuration of a two-hour BESS plus four ICEs, offering the lowest NPV OPEX among alternatives, aligns with current industry preferences for larger-capacity projects. This configuration balances the higher initial CAPEX with reduced operational expenses over time, considering both immediate and future financial commitments.

8.3.1 ICE STAND ALONE COMPARISON CASES

As comparative analysis, two cases involving 4 ICE, with a total capacity of 72 MW as per highest upwards aFRR requirements, are evaluated. In one case, referred to as '4 ICE', the ICE units are allowed to start-up and shut-down in response to system imbalances. In another case, termed '4 ICE Must Run', the ICE units maintain a base load of 66 MW. The base load allows the ICE units to supply downward aFRR by reducing the generation, while also having the ability to ramp up to 72 MW to meet upward aFRR needs.

While this second solution is technically capable of covering the aFRR requirements, it leads to higher curtailment due to the additional base load of 66 MW and higher gas consumption, and consequently CO2 emissions. It's important to note that those cases are included in this report solely for comparative purposes and do not represent a standard practice for balancing a system to increase RES penetration. The inclusion of this scenario provides a benchmark for understanding the impact of different operational strategies on system performance and RES integration.

The scenario without BESS proves to be not only counterproductive in facilitating the penetration of RES in the Moldova's system, but it also emerges as the most economically expensive solution for providing flexibility as shown in Figure 47. This underscores the importance of BESS in both the technical and economic aspects of RES integration and grid flexibility.

9 CONCLUSIONS AND RECOMMENDATIONS

This report provides a thorough assessment of the current and future requirements of the electricity balancing and LFC structure in Moldova's power system. Twelve scenarios were analyzed across a wide spectrum, mapping the evolution of the system in the two target years 2025 and 2030. The scenarios addressed three possible pathways for RES deployment in Moldova, as well as the availability of MGRES to supply the right bank. The assessment of concrete technical solutions to meet the system's present and future reserve needs was performed based on a holistic analysis of the system impacts.

The assessment of balancing reserve requirements for Moldova in both years found no changes for FCR and increased FRR requirements. The amount of FCR required is expected to remain at 5 MW, as per the current agreement with Ukraine. The assessment of FRR needs, based on a state-of-the-art probabilistic assessment methodology, found a requirement of about 240 MW of FRR to cover 99 percent of imbalances in 2025 and 2030. From this capacity, increased aFRR requirements at 60–72 MW are projected, corresponding to higher RES penetration in 2030. This capacity should consist of fast-ramping assets to cover fast variations in imbalances. Accordingly, mFRR+ requirements are estimated in the range of 163–174 MW. Under the conditions of the critical scenario with high flows from Romania to Ukraine, the analysis found no relevant violations in loading or voltages in the N-1 situation resulting from introducing ICE and BESS assets in the suggested locations. In principle, Straseni can properly accommodate the installation of the intended BESS, whereas Balti, Orhei, and Floresti can host the ICEs.

The final step of the analysis was to estimate the total project costs. The general breakdown is as follows:

- FCR: The total estimated cost of a 5 MW/5 MWh BESS is $8,779,630.
- aFRR: The BESS/ICE combinations were assessed through a detailed financial model, mapping the key NPV indicators. The configuration of a two-hour BESS with four ICEs is proposed, as it offers the lowest NPV OPEX among the alternatives and aligns with current industry practices. This configuration balances the higher initial CAPEX with reduced OPEX over time, considering both immediate and future financial commitments. The total estimated cost for aFRR provision is $151,639,840, corresponding to the costs of a 72 MW/144 MWh (two-hour) BESS at $74,800,000 and of a 72 MW/four-unit ICE at $76,839,840.
- mFRR: Considering the required capacity outlined in section 6.3 to meet mFRR requirements, a total installed capacity of 172 MW is necessary. Based on the findings of the market analysis, to meet mFRR requirements (172 MW), ten ICE units should be deployed, resulting in a total installed capacity of 180 MW. Furthermore, it is considered a best practice to incorporate a backup unit to ensure uninterrupted availability during maintenance periods. This leads to a total required capacity of 198 MW for 11 units. The total cost for ICE with 198 MW capacity is estimated at $211,309,560.

Therefore, the total cost estimate of the combined proposed solution is $371,729,030.

10 APPENDIX

This appendix presents the zonal model framework and its results (Activity 2). It is designed to offer a comprehensive understanding of the model's structure, methodology, and the key insights derived from its application, particularly focusing on aspects of generation, load, and flows:

- Moldova's generation, load, and flows: This section delves into the modeling approach of the power generation, load, and analysis of the flows among Romania, Moldova, and Ukraine and presents the RES penetration for each scenario.
- Ukraine's and Romania's generation and load: Focusing specifically on the aspects of generation and load, this section provides a detailed analysis of these two components.

The detailed results and analyses presented in this appendix provide further insights and augment the information on the zonal model's role in Chapter 5.

MOLDOVA

This section showcases outcomes from a specific scenario that effectively demonstrates the model's typical behavior in simulations, whereas RES penetration is presented across all scenarios.

GENERATION

The CHP generators were modeled as fixed profiles. shows the CHP generation fixed profile provided by Moldelectrica. Additional work was necessary to build the profile of the 2025 commissioned West CHP and new CET-1 units' configurations, the 2030 commissioned new CET-1 units' configuration, and bio.

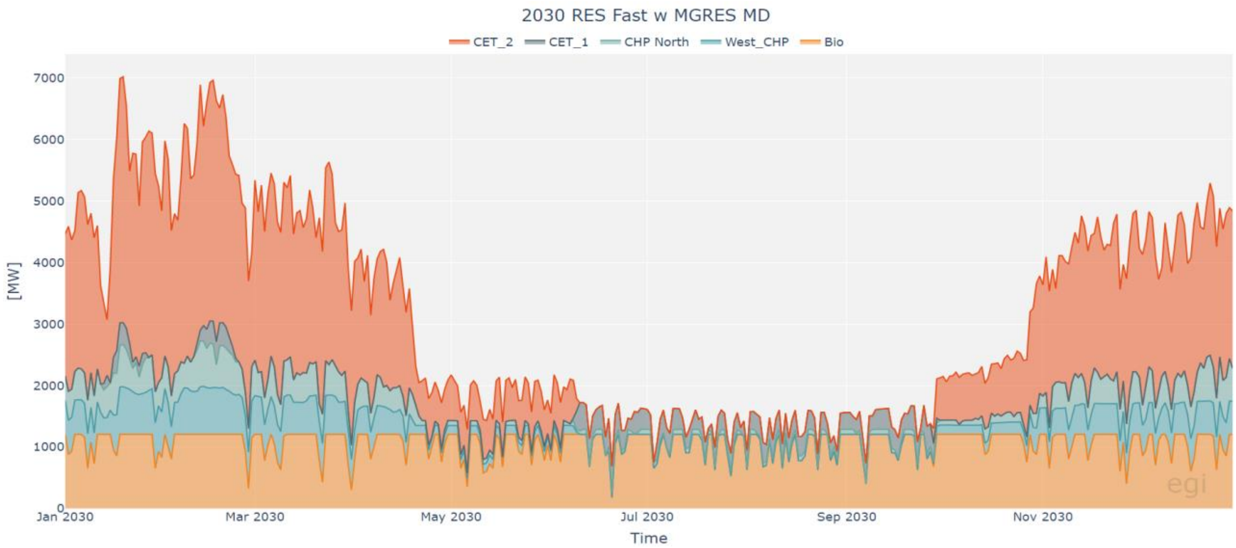


Figure 48 CHP generation fixed profile

Figure 49 shows the generation profile of the MGRES generators, which were modeled at a unit level, and the integer optimization was chosen.

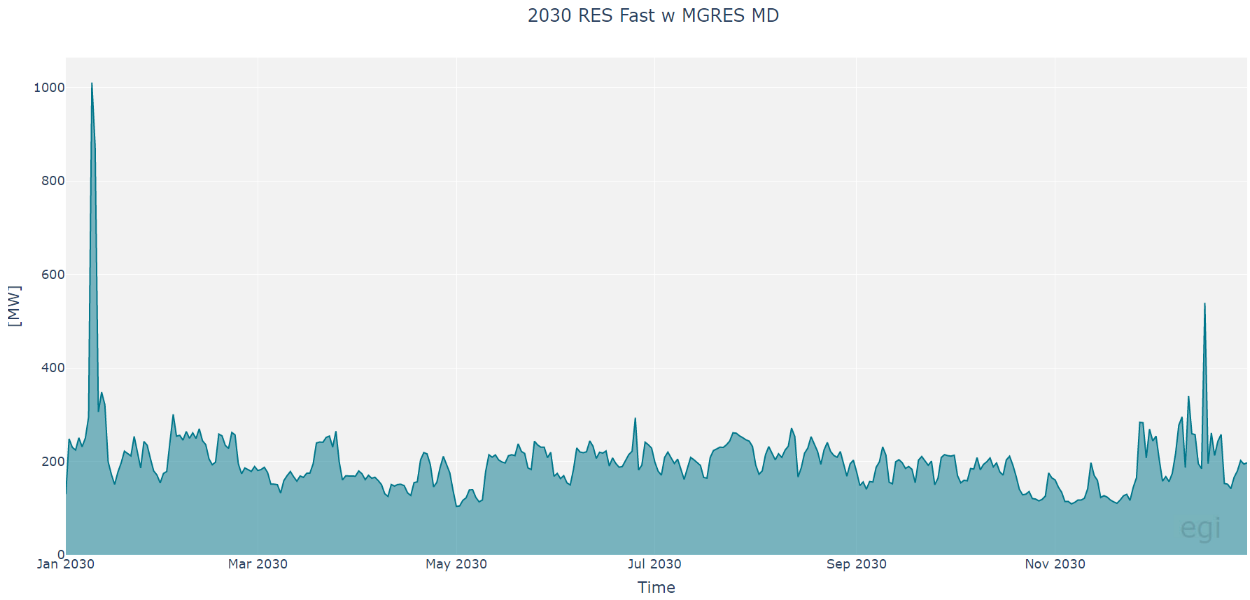


Figure 49 MGRES generation profile

Figure 50 shows the generation dispatch per technology in Moldova for the 2030 Fast scenario with MGRES.

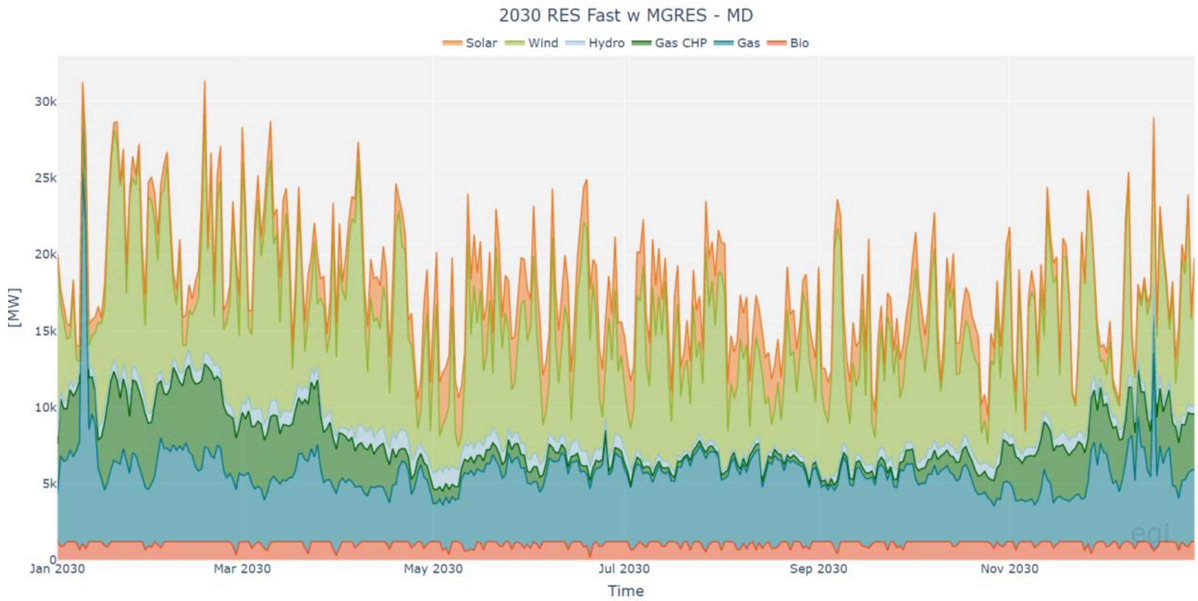


Figure 50 Moldova generation dispatch

LOAD

Figure 51 presents the hourly profile of Moldova for 2025 and 2030 as an integration of section 5.1.

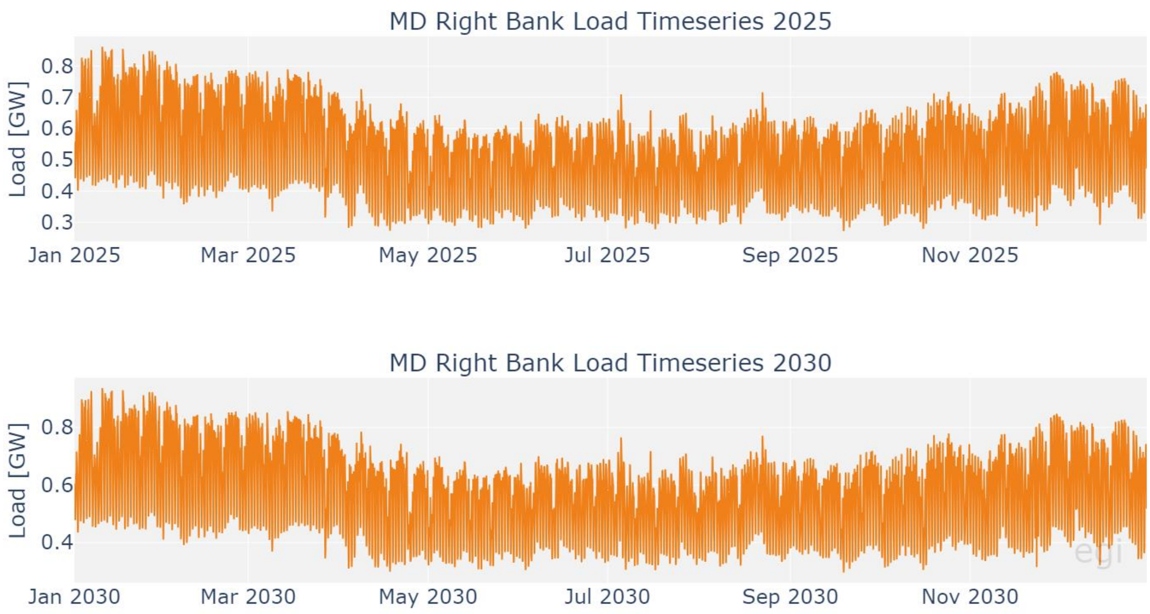


Figure 51 Moldova hourly load profile

FLOWS BETWEEN ROMANIA, MOLDOVA, AND UKRAINE

Figure 52 and Figure 53 show the daily total flows from Romania to Ukraine for the Base scenarios without MGRES in 2025 and 2030. In 2025, there are higher flows in winter months due to higher loads in Ukraine during winter, which is expected when looking at historical trends. Compared to 2025, 2030 also has an increased flow to Ukraine in summer months. This is due to the relatively similar installed generation capacities in Ukraine in 2025 and 2030 despite an increase in load over that period.

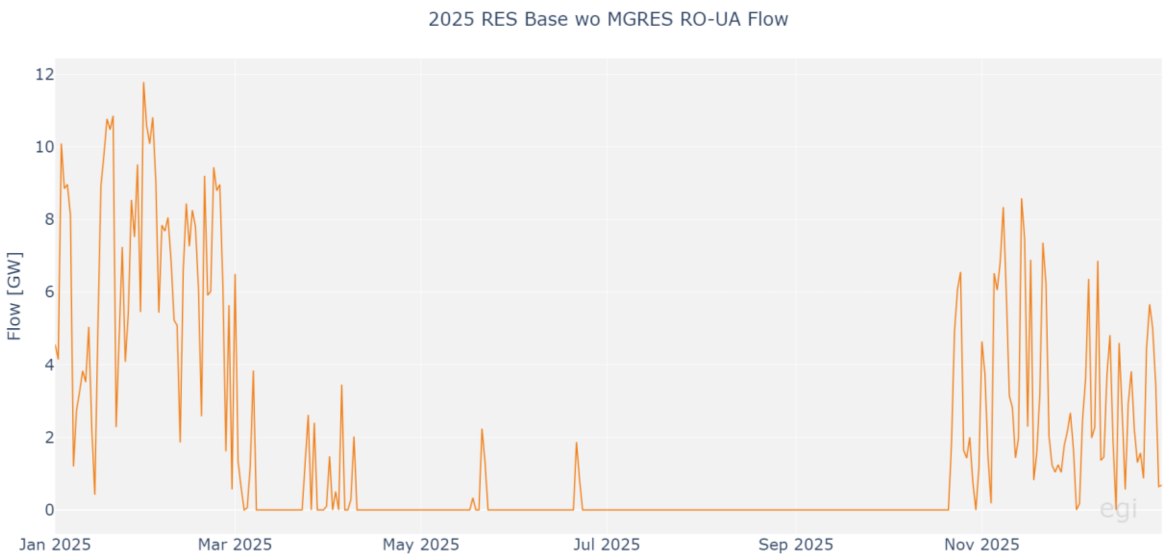


Figure 52 2025 RES Base wo MGRES – flows between Romania, Moldova, and Ukraine

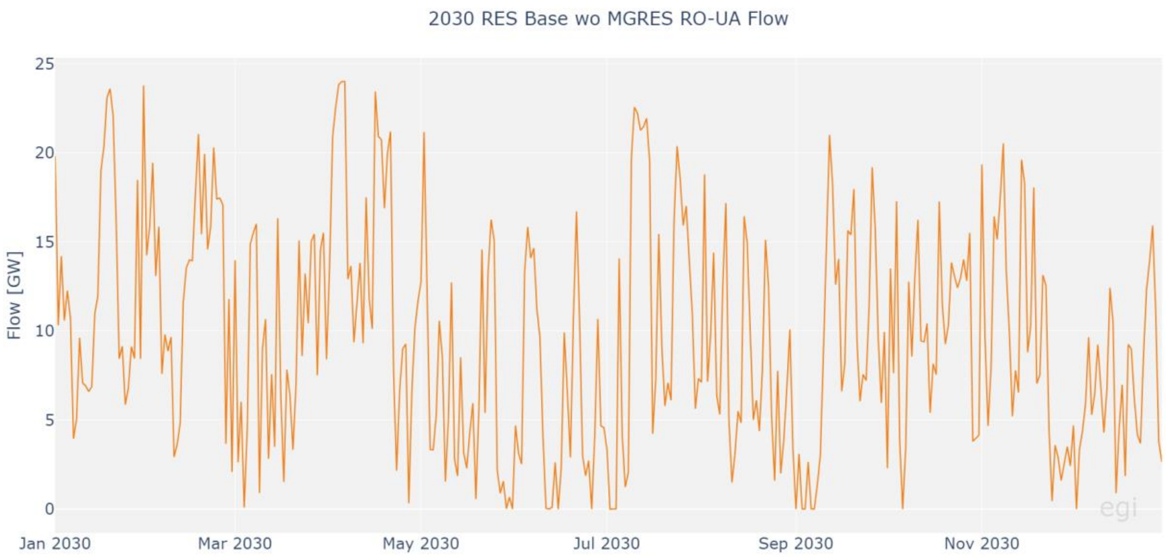


Figure 53 2030 RES Base wo MGRES – flows between Romania, Moldova, and Ukraine

Table 36 summarizes the hourly minimum, maximum, and average flow from Romania to Ukraine, showing an increase in average flows from 2025 to 2030.

Table 36 Flows from Romania to Ukraine

Flow [MW]	2025 RES Base wo MGRES	2030 RES Base wo MGRES
Mean	73.04	401.61
Min	0	0
Max	731.59	1,000

RENEWABLES PENETRATION

Table 37 presents RES penetration for each scenario. This was determined by the yearly total solar and wind generation as a percentage of the yearly total load and generation of the right bank. As a percentage of load, RES penetration is higher in 2030 than in 2025, and within each year, it is highest in the Fast scenarios.

Table 37 Renewables penetration for different scenarios

Scenario	RES penetration (% load)	RES penetration (% generation)
2025 Base w MGRES	24.45	56.35
2025 Base wo MGRES	24.45	56.73
2025 Fast w MGRES	31.96	62.48
2025 Fast wo MGRES	31.96	62.84
2025 Slow w MGRES	25.92	57.76
2025 Slow wo MGRES	25.92	58.14
2030 Base w MGRES	48.86	61.8
2030 Base wo MGRES	48.92	62.04
2030 Fast w MGRES	55.1	60.48

Scenario	RES penetration (% load)	RES penetration (% generation)
2030 Fast wo MGRES	55.19	60.7
2030 Slow w MGRES	47.17	62.5
2030 Slow wo MGRES	47.22	62.73

UKRAINE AND ROMANIA

This section highlights findings from a particular scenario that exemplifies the model's characteristic performance in simulations.

GENERATION

The generators in Ukraine and Romania were modeled as aggregated units per fuel type. Linear optimization was performed to avoid committing the aggregated units. The installed capacities per fuel type for 2025 and 2030 were obtained from the ERAA 2022 database. For the renewable generators (PV and wind), the capacity factor time series were used, which was obtained from Renewables.Ninja. Figure 54 and Figure 55 show the generation dispatch per technology in Ukraine and Romania, respectively, for the 2030 Fast scenario with MGRES.

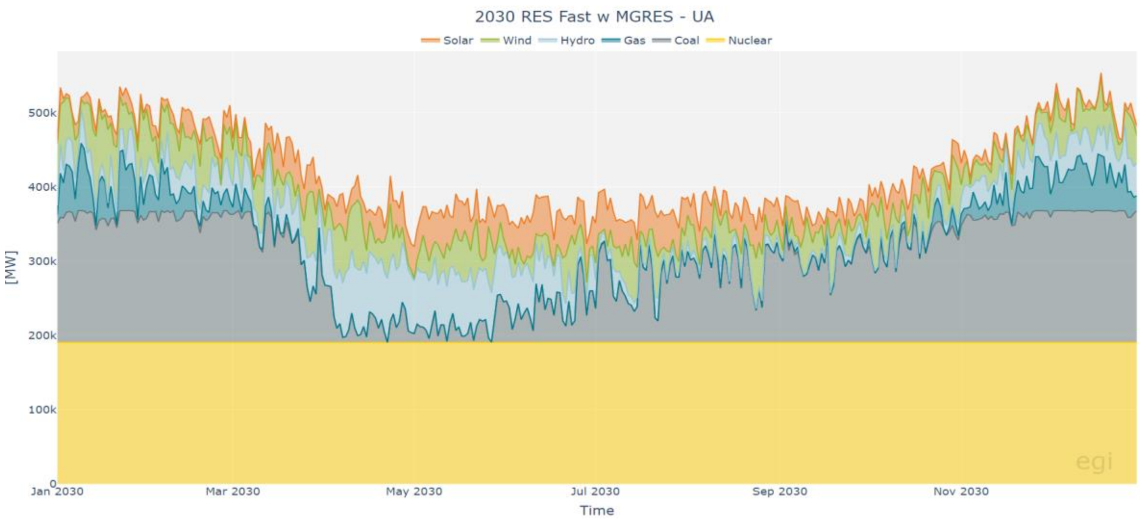


Figure 54 Ukraine generation dispatch

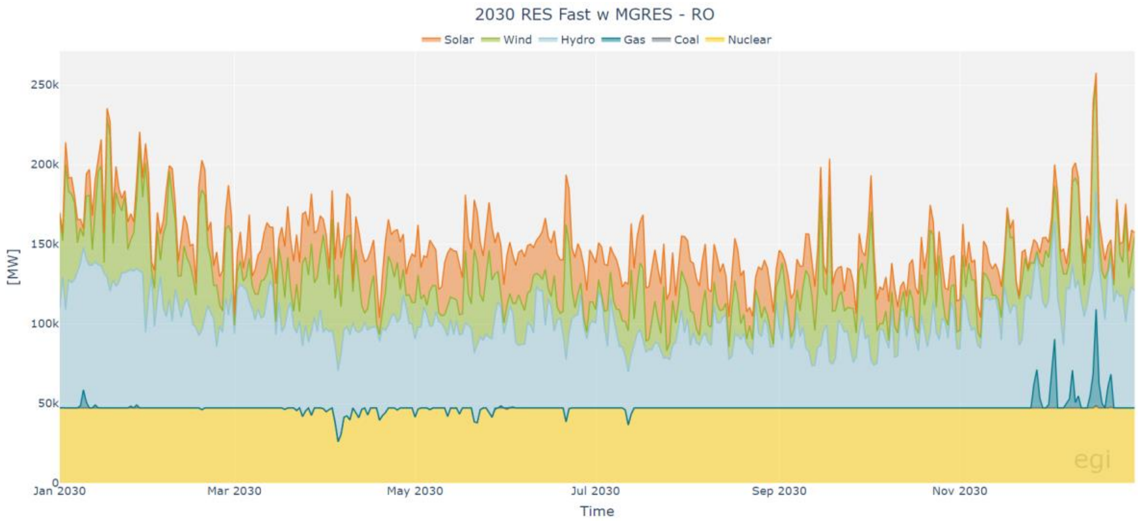


Figure 55 Romania generation dispatch

LOAD

Figure 56 and Figure 57 present the hourly profile of Ukraine and Romania, respectively, for 2025 and 2030 as an integration of section 5.1.

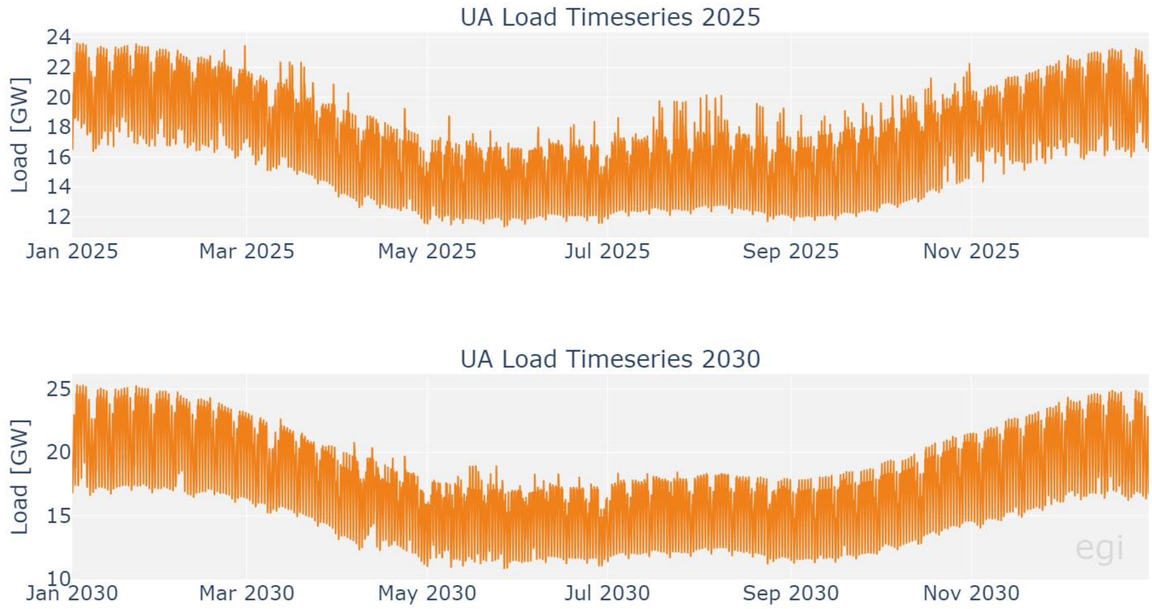


Figure 56 Ukraine hourly load profile

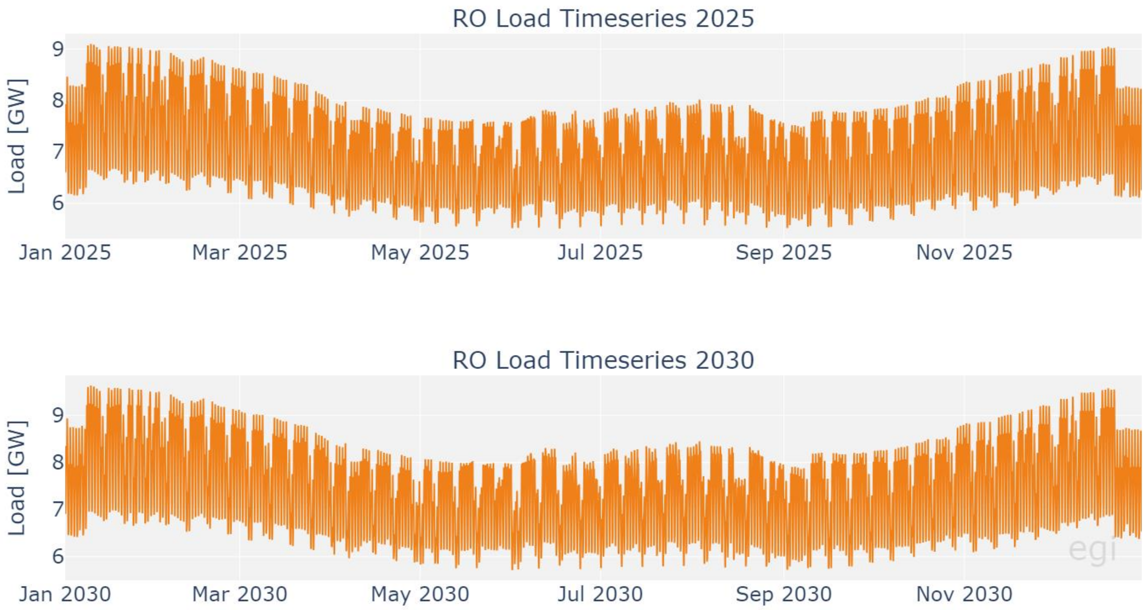


Figure 57 Romania hourly load profile

11 ADDENDUM – COMPARISON TO ALTERNATIVE CONFIGURATION AND OPERATIONAL STRATEGY

This addendum reports on an additional analysis conducted to further validate the proposed solution for aFRR asset size, as per section 6.2.3 and section 8.3, by exploring an alternative asset configuration and operational strategy that arose during the review process. The additional analysis tests the operation of this alternative configuration and examines its impacts on the reliability of the system and on system costs.

ANALYZED CONFIGURATIONS

The alternative configuration includes the following characteristics:

- **Fewer ICEs and smaller BESS size:** two 18 MW ICEs instead of four and a 50 MW/one-hour BESS instead of 72 MW/two hours.
- **Alternative operational strategy:** ICE operated as must-run.

The configuration was tested for the 2022 dataset using the model outlined in section 6.2.

RESULTS

The analysis found that the alternative configuration led to an aFRR+ shortage of 8.8 GWh for the whole year, mainly because the reduced battery size is not sufficient to contain the imbalances sustained in specific periods. As an example, Figure 58 shows the results from February 9, when the system experienced an aFRR+ shortage around 3 a.m., as indicated by the red line. At this time, the BESS did not have enough energy content, as represented by the blue line. This event illustrates one of many periods in the year with persistent imbalances, i.e., negative imbalances over longer durations, during which BESS energy is depleted and the ICE units are not sufficient to provide the needed frequency reserves. This is in line with the results shown in Table 22 in section 6.2.3, where configurations of larger batteries with two ICE units could not support the system during persistent imbalance periods. This emphasizes the need for the proposed solution of four ICEs to ensure 100 percent system reliability under all imbalance conditions during the year.

In regard to the sizing of the BESS, the results presented in section 8.3 remain applicable in this addendum as well.

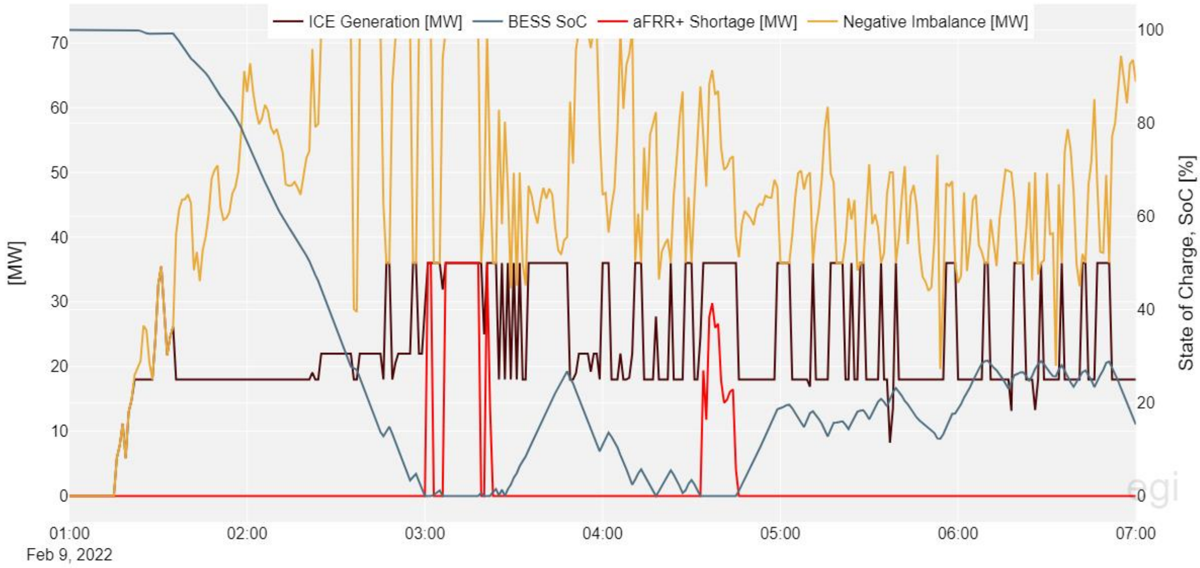


Figure 58 Snapshot depicting ICE generation, BESS SoC, aFRR+ shortage, and negative imbalances

From an operational point of view, setting the ICE units as must-run led to an increase in system operational cost. Firstly, the system experiences 65 percent more gas consumption compared to the operational strategy that prioritizes BESS in operations, leading to increased OPEX. Taking the market framework into account, an 18 MW must-run unit means the out-of-merit-order replacement of another generator in the system, which would prevent approximately 158 GWh of cheaper energy from being injected into the system. Such interference with the natural merit order of dispatch implies that a capacity mechanism would be required. If the must-run operation of the ICE (with an average generation cost of $71/MWh) were to replace nuclear generation (with an average generation cost of $29/MWh), the additional costs (subsidy costs) of the system would be an estimated $6.5 million per year. These additional costs would increase total system costs unless subsidized.

Figure 59 Financial comparison between different asset configurations

From the financial model results shown in Figure 59, the alternative configuration results in higher total costs despite a lower CAPEX due to a higher OPEX of $189 million. The NPV for the alternative configuration is estimated to be $260 million, which is $44 million higher than the proposed solution in section 6.2.3 and section 8.3. Therefore, to minimize the total cost for the system in terms of NPV, which includes reducing OPEX, the preferred solution is an operational strategy that prioritizes BESS.

CONCLUSION

To summarize, the alternative configuration of **two 18 MW ICEs with** a **one-hour, 50 MW BESS** does not outperform the proposed solution in section 6.2.3 and section 8.3 for three main reasons. Firstly, it lowers the reliability level of the system with an aFRR+ shortage of 8.8 GWh compared to 100 percent reliability in the proposed solution. Secondly, this configuration results in higher total system costs of $260 million measured in terms of NPV for a ten-year time frame. Lastly, while the alternative one-hour BESS does present some technical challenges and may not fully align with manufacturer recommendations, it could still be a viable option under certain circumstances.