ENERGY TECHNOLOGY AND GOVERNANCE PROGRAM

Study on System Adequacy and Flexibility of the Macedonian Power System

– Final Report –

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Final Report

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ABBREVIATIONS

CCGT	–	Combined Cycle Gas Turbine
EIHP	–	Energy Institute Hrvoje Požar
EMI	–	Electricity Market Initiative
EENS	–	Expected Energy not Served
ENS	–	Energy Not Supplied
EU	–	European Union
EU ETS	–	European Union Emissions Trading System
EVA	–	Economic Viability Analysis
IPEX	–	Italian Power Exchange
LLD	–	Loss of Load Duration
LOLE	–	Loss of Load Expectation
MAF	–	Mid-term Adequacy Forecast (Pan-European assessment of power system resource adequacy prepared every year by ENTSO-E)
MEPSO	-	Macedonian Power System Operator
NTC	–	Net Transfer Capacity
OCGT	–	Open Cycle Gas Turbine
O&M	–	Operations and Maintenance
PECD	–	Pan-European Climate Database (developed by ENTSO-E)
PEMDB	–	Pan-European Market Database (developed by ENTSO-E)
PSHPP	–	Pumped Storage Hydro Power Plant
RAA	–	Resource Adequacy Analysis
RES	–	Renewable Energy Sources
ROR	–	Run-of-River
TSO	–	Transmission System Operator

TYNDP	–	Ten-year Network Development Plan (Europe's Network Development Plan prepared bi-annually by ENTSO-E)
USAID	–	United States Agency for International Development
USEA	–	United States Energy Association

1 EXECUTIVE SUMMARY

The transition taking place in the power sector in the EU, and in Southeast Europe (SEE) and North Macedonia in particular, is monumental. This in-depth study by the Electricity Market Initiative (EMI) is a collaboration between MEPSO, USEA, and its consultants EIHP, in partnership with USAID, and it provides a Resource Adequacy Analysis (RAA) that addresses potential risks to power supplies, and how the Macedonian power sector can best navigate the challenges that may arise.

The foremost of these challenges is to completely revamp the generation and use of electricity by massively decreasing carbon-based sources, dramatically increasing cleaner (largely variable renewable) generation, while maintaining a system in which power supplies remain reliable and affordable, and doing so quite soon. Coupling and creating integrated power markets across SEE is a key element to help meet those challenges.

North Macedonia has been a true leader in these areas in the Western Balkans, including the adoption of a progressive National Energy Climate Plan; auctions for renewables; strategic deals for large wind and solar investments; plans to eliminate fossil generation; and active participation in regional initiatives (e.g., Open Balkans, market coupling).

While these efforts are laudable and ambitious, it is challenging to quickly eliminate the use of carbon-based power in the Western Balkans, as fully two-thirds of power generation in the WB6 in 2021 relied on such sources, along with thousands of jobs. Doing so can raise the risk of unreliable electricity supplies, and can increase the cost of electricity to much higher levels. It is most desirable for the climate-and-cost motivated transformation of power generation to take a balanced approach that is both urgent and carefully planned, with accompanying adjustments to the transmission and distribution networks. The EU is a world leader in this regard.

In addition to prior actions, in 2019 the EU significantly changed its energy policy framework and developed the Clean Energy for All Europeans package, putting into force Regulation (EU) 2019/943 of the European Parliament of 5 June 2019 on the internal market for electricity.

Further, the energy crisis and high fuel and power prices of the past year, and Russia's war in Ukraine (with its policies to restrict, and in some cases cut off gas supplies to EU members) have given added motivation to find alternative suppliers and to break free of Russian and carbon-based sources. A number of EU and non-EU members have passed resolutions, are making major transition plans, and are reducing fuel imports from Russia as a result.

In late 2021, the EMI finalized a study that simulated the impacts of significantly reducing carbon-based generation in SEE, under scenarios that would eliminate up to 80% (18 GW) of existing lignite and coal generation capacity by 2030, while nearly quadrupling the level of RES. The study showed that doing so could reduce CO_2 emissions by 50% or more, depending on what replaces the existing fleet, and that it would require over \$50 billion USD in new power plant investment to replace the widespread decommissioning of lignite and coal plants. Such investment will come largely from the private sector, while also engaging energy efficiency and new technologies. We assumed that all markets in SEE would be coupled by that time, which would raise cross-border flows.

This EMI study also showed that the regional, cross-border and internal networks can absorb all these changes, and keep the supply of energy reliable, unless countries restrict such flows. This is the major transition that SEE, and North Macedonia in particular, are engaged in.

The need to manage this transformation is a fundamental reason for ACER's decisions in October 2020 on the Methodology for Resource Adequacy Assessment (Decision 24-2020), which sets the approach for evaluating how electricity markets should function to enable a smooth integration of variable RES, with the necessary flexibility. It emphasizes the importance of proactive planning to ensure that investment and regulatory decisions are in line with future needs.

The European Resource Adequacy Assessment (ERAA), as well as more local and country-specific RAAs, can address this challenge, along with ENTSO-E analyses such as the Ten-Year Network Development Plan (TYNPD) and other joint TSO actions. The ERAA is built on TSO expertise and know-how gathered over years of assessing resource adequacy deterministically in the period 2011-2025 (Scenario Outlook and Adequacy Forecast – SOAF) to the probabilistic assessment in the Mid-term Adequacy Forecast (MAF) up to 2020.

ERAA is a tailored approach to addressing today's electricity supply needs. In the process, there are several key factors to recognize with respect to ERAA work:

- It is best if all ENTSO-E members apply the ERAA Methodology (even beyond the EU) to provide a consistent, comparable and harmonized assessment. A look across the whole system can point out potential risks which would be difficult to spot from a local perspective
- National and regional RAAs provide a more granular picture and focus on sensitivities and potential solutions most relevant to the observed area.
- **While not a precise prediction tool, ERAA is an early warning system for potential future vulnerabilities.** It gives key information to decision makers (policymakers, regulators, TSOs) to move proactively and enable the transition to a climate neutral power system by 2050, without jeopardizing security of supply or unduly raising costs for customers.

The key question which ERAA should answer is: Is there a risk that all customer demand cannot be met over the course of a year, and if so, how large is that risk? ERAA does so by analyzing the balance between supply and demand, under possible future conditions, including various flexibility sources and grid interconnections. This is the "adequacy" assessment, and the metric used to answer this question is whether there is meaningful Loss of Load Expectation (LOLE). LOLE provides a risk assessment and economic trade-off for policy makers and regulators to evaluate and act upon. If the projected LOLE value is high, then the economic cost could be high as well, and the question that ERAA poses is – what are the options and best ways to mitigate if not eliminate it?

Answering that question requires further analysis, including economic viability assessments (EVA) of the alternatives, which in turn involve the application of hurdle rates to determine whether an investor is likely to undertake such a project. This pathbreaking EMI study addresses these complex and timely matters.

Through this study performed for North Macedonia, **we addressed the key ERAA questions through an analysis of two possible development scenarios in the Macedonian power system in 2025 and 2030, and 19 additional sensitivity analysis in which we changed some key parameters to analyze their impacts on the results.**

We took the entire power system of Europe into account in developing the model for this study. We used the Antares software tool, with the goal of showing whether any period of time would have unserved energy that would signify a potential problem with adequacy in the Macedonian power system. We also took many possible weather conditions into account by modelling 37 climatic years for all the modelled countries.

In the end, our 20 scenarios/sensitivities showed no issue with the adequacy of the Macedonian power system, which shows that its geographical position and interconnectivity with neighbors, along with existing and planned installed capacities, should suffice through 2030. This included an assessment of limited natural gas availability in Western Europe, and limited lignite availability in Southeast Europe to capture recent conditions. However, the results also show a substantial dependency on imports, with North Macedonia being a net importer (in some cases, quite a large one) in all scenarios and sensitivities.

Because of this dependency, we analyzed a case that assumed that a combination of conditions would arise that would limit imports from neighboring countries to 70% of imports from the Base Case scenario. This analysis showed that such conditions would damage Macedonian adequacy and result in an inadequate system. While such conditions may not be likely, it shows that the Macedonian power system may wish to consider its reliance on imports, a policy question that decision makers could investigate in future iterations of the ERAA analysis.

We further conducted a basic economic viability assessment (EVA) by investigating the revenues and costs of gas power plants in North Macedonia to simulate a private investor's decision. This report presents a first step to consider capacity resource mechanisms, and the complex process of commissioning and decommissioning future generation projects on a routine basis.

In the EVA, the existing large TPP TE-TO was economically viable, along with a new gas TPP, as well as a TPP that could fill the gap in the case of limited imports.

The EVA is a complex process that we recommend be further developed and researched to fully comply with Macedonian circumstances, and to bring additional analytic resources to conduct the fully iterative process necessary to choose the best path forward.

We also conducted a flexibility analysis to explore any flexibility needs in 2025 and 2030 in the Base Case, particularly with higher RES penetration which introduces variability and ramping needs. **This assessment shows that Macedonian flexibility needs significantly increase with the rise in RES integration. Over time, this rise will increase the need in North Macedonia to plan for such flexibility.**

2 Introduction

Until now, the system adequacy and flexibility of the Macedonian power system were estimated in a deterministic manner (based on the worst-case scenario, no matter its probability). However, as the generation mix evolves towards a high share of renewables, this approach is becoming obsolete, due to the stochastic nature of the renewable energy systems (RES), their intermittency, and the power system operation based on open electricity market conditions. These changes raise the question of power system adequacy in the short, medium, and long run.

In addition, the integration of large amounts of RES must be closely matched with the commissioning of devices and markets that can provide sufficient power system flexibility and balancing capabilities.

Further, it might prove worthwhile to look into discrepancies between the adopted legislation in North Macedonia and the rest of Europe, especially in the well-developed European countries. Adoption of the EU Energy Legislative is an ongoing process in North Macedonia. This legislation will require MEPSO to calculate power system adequacy using probabilistic criteria in the future. North Macedonia may be able to address issues of system adequacy and flexibility with soft measures through the strategic adoption of additional EU legislation that could facilitate different technologies by changing the current sector rules.

The current global energy changes will affect individual countries' strategies and decisions from now on. For example, the current shortage of gas, problems with older coal plants, and unprecedented power prices will impact the handling of the winter crisis of 2022/2023, and will surely be a starting point for changes in the generation mix of many countries, even those highly reliant on fossil fuels. In addition, these changes must protect the security of supply for consumers, as well as ensure the safety and reliability of the power system.

These factors, along with technological shifts and changes on the demand side, are the drivers of this study. Along with the ENTSO-E mandated rule on performing resource adequacy studies, it is in the best interest of the Macedonian power system to conduct this analysis regularly, to be aware well in advance of any possible future difficulties. MEPSO, as the Macedonian TSO, has a strong basis for performing such analyses to anticipate any gaps in adequacy. MEPSO is also highly motivated to continue to improve the methodological approach and scenarios to fully capture and adapt to future conditions.

3 SCENARIOS AND DATA

MEPSO chose the scenarios and sensitivities for this study to take into account the future plans for the Macedonian power system, as well as some possible changes that could impact the security of supply in North Macedonia and thus affect system adequacy. The basic scenarios, with the most likely development of the Macedonian power system regarding power demand, level of RES and generation mix in 2025 and 2030, include:

- The Base Case Scenario
- the Base Case Scenario with a Capacity Remuneration Mechanism (CRM).

Additionally, we modeled several integral sensitivities, as follows:

- High RES
- Low RES
- Carbon price
- High demand
- No new TPPs
- No new HPPs
- A green transition sensitivity, with moderate decarbonization as in the EMI 2021 study
- Faster pace of RES development in SEE
- Limited imports to the Macedonian power system
- Winter crisis sensitivity (for 2025).

We modified and selected the chosen sensitivities based on changes in energy conditions since the start of this project in 2021. This mostly applies to the green transition scenario, which takes into account the future path of the European countries that have a set goal of reaching net zero emissions by 2050. To achieve that, all countries must take earlier steps. In particular, countries must adjust immediately to conditions in 2022, when fossil fuels from Russia are or are becoming unavailable. In this light, we chose the moderate EMI decarbonization scenario (a reduction of about 2/3 of coal and lignite generation by 2030), since it is not likely that in the next few years the countries of SEE will shut down more of the fossil fueled power plants than in that analysis.

To further explore the decarbonization option that has somewhat become unavoidable due to recent circumstances, we added a winter crisis sensitivity for 2025 in the final stage of this project. This analysis determines the outlook for North Macedonia in 2025, since the conditions of 2022 might still have an impact then. The next Chapter provides details on this sensitivity.

We show all the modelled scenarios and sensitivities in Table 3.1 below. It made sense to capture some of the factors at the national level, and evaluate others for the region as a whole.

Table 3.1: Summary of analyzed scenarios and sensitivities with MEPSO

Scenario/sensitivity	National/regional impact
Base Case	National
Base Case Scenario with CRM	Regional
High RES	National
Low RES	National
Carbon price	Regional
High demand	National
No new TPPs and HPPs	National
Moderate decarbonization	Regional
Fast RES pace	Regional
Limited import	National
Energy crisis	Regional

The main objective of this study with MEPSO – and for ERAA assessments more broadly - is to determine whether and how often available generation capacity and imports are not sufficient to meet demand. To achieve this, we simulated the entire European electricity market on an hour-by-hour basis, and carefully assessed the output. If, for a given hour, the combination of generation capacity and imports is unable to meet demand, this corresponds to one hour of structural shortage (i.e., one loss of load hour or energy not served). Once we identify all the hours in which there are shortfalls, if any, we can calculate the following indicators:

- LOLE: Loss of Load Expectation, which are the expected annual hours with a loss of load over the simulated Monte Carlo years
- EENS Expectation of Energy Not Served per year over the simulated Monte Carlo years.

3.1 Studied time horizons

The study uses two time horizons, **short-term** and **mid-term**. **Article 4.1 (b) of the ERAA methodology clearly defines the time horizons** that should be analyzed. Generally speaking, the short-term horizon is five years, and the mid-term horizon is ten years from the starting point. For this analysis, those would be **2025 and 2030**, since this project began in early 2021.

These two time horizons enabled us to capture the assumptions and conditions needed to provide reliable results for the expected adequacy and flexibility of the power system. Furthermore, the Strategy for Energy Development of the Republic of North Macedonia (Energy Strategy) looks out to 2040, with detailed data for 2030. So, while the mid-term horizon will determine the system adequacy and flexibility now, it will also identify any potential gaps in adequacy in time to prepare longer-term solutions. This was also an important reason for choosing these target years.

3.2 Modelling assumptions

We describe the assumptions used to model the Macedonian power system using Antares below. This section also describes the assumptions to create the scenarios and sensitivities, and the technical and economic assumptions for all the power systems.

3.2.1 Base case scenario

The Base case scenario represents the most probable future state of the Macedonian power system. We took multiple variables into consideration, such as levels of RES, commissioning and decommissioning of power plants, and the demand level, which MEPSO provided. The Base case scenario assumes no unexpected events, and that all plans to construct new capacity will be realized.

3.2.1.1 Electricity consumption

Adequacy analysis must assess the total electricity consumption that the system needs to meet, and in this study, we included final electricity consumption, energy sector electricity use, and distribution and transmission losses, while excluding power for pumping and plant self-consumption. This projected load in the base case for North Macedonia amounts to 8,0 TWh in 2025 and 8,4 TWh in 2030. We used load profiles in line with the "green" scenario from the Strategy for the North Macedonian power system, and for the rest of the region, we used the TSOs' data from the EMI 2021 study. For the rest of the Europe, we used PEMMDB data.

3.2.1.2 Renewable energy sources

Wind and solar

The data for the RES levels in terms of wind and solar capacities is in line with the expected levels of wind and solar in 2025 and 2030. Table 3.2. shows the projected RES levels for our target years.

Table 3.2: Installed wind and solar capacities in North Macedonia (Base case scenarios)

Scenario	Technology	Installed capacity(MW) Short-term horizon	Installed capacity(MW) Mid-term horizon
Base case	**Wind**	180	443
	Solar	203	563
TOTAL		383	1.006

We modelled the RES production profiles detailed MEPSO data on wind speed and direction for several locations in North Macedonia. We also compared this data to prior studies, specifically, with the climatic adaptation of wind and solar hourly profiles in line with the Pan European Climate Database (PECD).

The recently adopted ERAA methodology requires that in the future, the PECD reflect the evolution of climatic conditions as depicted in Article 4 (f). The first option described in the ERAA methodology is that the targeted approach would use a best forecast of future climate conditions. The second option is to weight climate years to reflect their likelihood of occurrence (taking future climate projection into account), and the third option is to rely on the 30 most recent historical climatic years or more in the PECD.

EIHP and MEPSO agreed on the third approach, taking 35 climatic years into account, since we have data available for 35 years. We applied this approach for all market nodes for both RES and demand using PEMMDB and PECD, taking into account the expected frequency and magnitude of future climate conditions, as well as future uncertainty.

Hydro

North Macedonia has nine hydro power plants (HPPs), of which five are seasonal storage and four are run-of-river. There are also plans for future construction of four hydro power plants. One of those is the pump-storage HPP Cebren. The others are run-of-river HPP Vardar Valley, and the Veles and Gradec HPPs, both weekly storage, planned to begin operating in 2030. The total installed hydro capacities are shown in Table 3.3.

Table 3.3: Installed hydro capacities in North Macedonia (Base case scenario)

HPP	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
TOTAL	785,1	1.309,8

3.2.1.3 Thermal power plants

The national decarbonization strategy in North Macedonia envisions decommissioning the lignite-fired TPPs, TPP Bitola 1, Bitola 2, Bitola 3, and Oslomej, as well as the oil-fired TPP Negotino, during the short-term horizon (by 2025). The plants being decommissioned total 939 MW. All of the TPPs in Table 3.4 are fueled by natural gas. The Macedonian national strategy includes the commissioning of a new biogas plant by 2025, which we include in the short-term and mid-term models accordingly.

We show all existing and newly installed thermal capacities by the mid-term target year in Table 3.4.

Table 3.4: Installed thermal capacities in North Macedonia (Base case scenario)

TPP	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
TE-TO	250	250
New Gas TPP	141	141
Kogel	30	30
Kogel Elem	30	30
Biogas PP	26,6	26,6
TOTAL	336,6	336,6

3.2.2 Base case with CRM

Adequacy studies mandated by the ERAA 2021 methodology primarily seek to determine if there are likely to be shortfalls in the ability to meet future electricity demand in individual countries. But this methodology was also developed to discourage unneeded capacity remuneration mechanisms, as in many European countries, as an ENTSO-E study of European resource adequacy recently found. While there are no foreseeable plans for a Macedonian CRM, MEPSO agreed that CRM would be implemented in the model in all countries in SEE that already had such plans in the studied time horizons. An unnecessary CRM would be one not justified by a lack of adequacy proven by an analysis like this one. CRMs should only be implemented if adequacy analyses show a significant issue with meeting customers' needs for electricity that cannot be resolved otherwise.

ACER noted in 2020 in their NRAA assessment that some countries did not take into account the contribution of interconnectors to adequacy, and they therefore detected adequacy issues when none existed. Therefore, ERAA and ENTSO-E recommend that countries should first do a resource adequacy analysis, and then only implement CRMs if such analysis shows significant adequacy issues, and then only if no other solution is available, and both the ENTSO-E for Europe and national adequacy assessments find adequacy issues. As mentioned, the purpose of the ERAA is to bring benefits to consumers by limiting the use of CRMs where they are unnecessary.

Our research for this study shows that only Bulgaria and Greece have some plans for CRMs, and only in the form of strategic reserve, in which they withhold some capacity for emergency cases. Therefore, these countries were calibrated to their reliability standard by removing generation capacities responding to those strategic reserves.

All the other assumptions for this scenario coincide with the previously explained assumptions for the Base case scenario.

3.2.3 Sensitivities

There are many future unknowns in the development of a power system, and each one can impact the system's adequacy. To help MEPSO and its regulators develop a more robust system, across a range of future conditions, the central reference scenario is diversified with sensitivity analyses. With MEPSO, several variables were chosen for these sensitivities to test their impact on the results. One parameter at a time is changed, while the others are kept constant

3.2.3.1 High RES

High level of variable RES is analyzed, as this can be highly challenging when it comes to maintaining system adequacy on a regional level, as well as system flexibility. This sensitivity is based on the "green transition scenarios", which predict a higher level of RES integration in the target years. There are two High RES scenarios, one for each target horizon, as shown in Table 3.5.

Table 3.5: Installed wind and solar capacities in North Macedonia (High RES sensitivities)

Sensitivity	Technology	Installed capacity(MW) Short-term horizon	Installed capacity(MW) Mid-term horizon
High RES	**Wind**	450	1100
	Solar	800	2000
TOTAL		1.250	3.100

3.2.3.2 Low RES

The impact of Low RES is also tested, in case RES development is postponed (see Table 3.6). This is important also for the adequacy study in case the imagined level of solar and wind power plants is not built and if it will impact the adequacy of the system in all hours.

Table 3.6: Installed wind and solar capacities in North Macedonia (Low RES sensitivities)

Sensitivity	Technology	Installed capacity(MW) Short-term horizon	Installed capacity(MW) Mid-term horizon
Low RES	**Wind**	50	180
	Solar	60	203
TOTAL		110	383

3.2.3.3 Carbon price sensitivity

We have chosen carbon prices as a sensitivity given their significant rise in recent years, to levels well above those expected in the ENTSO-E TYNDP 2020, and also, the demonstrated impact of CO_2 prices on the dispatch of TPPs in recent EMI studies. We agreed to use the emissions costs from the TYNDP 2020 published by ENTSO-E since it was considered as the only reliable source for this parameter. The TYNPD 2020 presumes a price of 27 EUR/t in 2025 and 53 EUR/t in 2030.

This CO_2 price value is applied for all countries and scenarios in this Study, except the sensitivity with a high CO_2 price. In that sensitivity CO_2 price is higher, in line with the trends on emission market and in line with ERAA 2021 predictions. This approach will provide consistency, given that half of the modelled countries are EU member states, while the remaining half are non-EU countries that are still not obliged to implement the CO_2 emission trading scheme. This results in 40 EUR/t in 2025 and 70 EUR/t in 2030 for the High CO_2 sensitivity.

While the CO_2 tax must be applied for all EU member states there is still a question about its application for non-EU countries. Considering that we are analyzing horizons five and ten years from this study, the same CO_2 tax is applied to all market areas. This approach assures consistency of the operating costs level and comparable results with ENTSO-E projections. Modeling of some market areas with the CO_2 price and some without would create a significant disparity for those countries not in the ETS system, and it seems reasonable that all modelled countries will be part of the EU ETS by 2030.

In addition to the carbon price, the emission factor of each fuel type has to be applied, since both elements (combined with the unit efficiency) determine the carbon content and hence the cost to operate each unit. The emissions factors used for each fuel category are from the ENTSO-E common data, for the TYNDP framework, and MAF studies, as published by ENTSO-E.

3.2.3.4 High demand

Higher demand than expected may negatively impact adequacy and result in hours of unsupplied energy, so its impact is analyzed with a sensitivity analysis. In the short-term and mid-term, high demand will be 8,0 TWh and 8,4 TWh, compared to the Base case scenario of 7,8 TWh and 8,6 TWh in 2025 and 2030.

3.2.3.5 No New HPPs and TPPs

Through this sensitivity, the goal was to test the impact of no new investment into generation fleet of North Macedonia. The HPPs in question are PSHPP Chebren and storage HPPs Veles and Gradec, which are planned for commissioning between short and mid-term horizon and the TPP in question is the gas TPP planned for commissioning in 2025 with 141MW of installed capacity. This sensitivity is chosen to demonstrate whether the delay in generation fleet investment can cause hours of unsupplied energy.

3.2.3.6 Decarbonization

This sensitivity follows the Moderate scenario of regional decarbonization from the latest EMI study in terms of assuming an earlier decommissioning date for some thermal power plants in the region. The goal of this sensitivity is to analyze the possibility of having lower amount of fully reliable and available capacity, which is exactly what thermal power plants are, and what the impact would be on Macedonian adequacy. Of course, this is also done having in mind the environmental constraints that are bound to force some of these decommissioning's in the future therefore making this analyzed situation a reality. Table 3.7 shows the amount of decommissioning's in the region considered in this sensitivity.

Table 3.7: TPP commissioning and decommissioning in the EMI region in the Decarbonization sensitivity

Market area	TPP capacity decommissioned in the Moderate scenario (MW)	Total TPP capacity in operation in the Moderate scenario (MW)	Rate of TPP capacity decrease - Moderate scenario
OST	100	200	-33.3%
NOSBiH	190	1,442	-11.6%
ESO EAD	658	4,070	-13.9%
IPTO/ADMIE	600	7,167	-7.7%
HOPS	105	876	-10.7%
KOSTT	450	528	-46.0%
CGES	0	225	0.0%
MEPSO	0	586	0.0%
Transelectrica	1,493	8,562	-14.9%
EMS	795	4,033	-16.5%
ELES	767	990	-43.7%
TOTAL	**5,159**	**28,678**	**-15.2%**

3.2.3.7 GR RES pace

This sensitivity follows the Greek sped-up RES pace for the entire region (except North Macedonia, for which the RES levels have been determined and explained in previous chapters). This Greek RES pace envisions a two times higher increase in solar capacities by 2025 and 1,5 by 2030 and 2,2 times higher for wind in 2030 and 1,4 in 2030.

3.2.3.8 Limited import

This sensitivity tests the significance that energy imports hold on the Macedonian power system. Since North Macedonia is a net importer, it was important to show what the impact would be if there was a problem with outside supply. Therefore, we ran a sensitivity that limits imports to 70% of the Base Case scenario, with its results in Chapter 5.3.

3.2.3.9 Winter crisis

We added this scenario, as stated earlier, since an analysis as thorough and important as this one needs to assess the possible impact of the global energy crisis on the Macedonian power system. To capture such circumstances, we made several assumptions:

- This sensitivity is only run for 2025, since we do not expect this crisis to continue to 2030.
- Unlike the other cases, which used 35 climatic years, in this case we only analyzed dry hydrology. Dry hydrology has become more common, and it presents a significant stress on supply security, especially for countries with a large share of HPPs such as North Macedonia.
- We reduced the lignite capacity in the EMI region by half, in line with the current situation with open lignite pits, indicating that lignite TPPs could be jeopardized in the winter of 2022 and beyond. We have found recently that lignite pits are not adequately prepared for generation in normal circumstances, let alone for an energy crisis.
- The gas TPPs in the EMI region remain fully available, since we expect there will be sufficient gas in the region, given the region's diverse supply options (such as LNG stations). We did

not add any new gas TPPs, and we only decreased the capacity of gas TPPs in Western Europe due to the unavailability of fuel (gas).

On the other hand, we reduced the capacity of gas TPPs in Western Europe by half due to its dependence on Russian gas and the challenges of replacing it quickly, and we kept the lignite TPPs fully available in Western Europe, where a lignite shortage is not expected. The reduction of gas capacity by 50% is around 11.8 GW in Germany, which is the country in Western Europe most dependent on Russian gas.

In general, gas demand in Western Europe is significantly greater than LNG capacities, compared to SEE, so SEE energy security is less jeopardized with the gas shortage. Moreover, some SEE countries (such as BA, AL, ME, and XS) have no gas TPPs.

All other assumptions remained the same.

3.2.4 Neighboring countries

We modelled the ten countries from the region that have the biggest impact on North Macedonia with the same granularity as North Macedonia (generation units, storage facilities, renewables, consumption, hourly RES profiles) etc.). The TSOs in SEE provided this data in the EMI 2021 decarbonization study, and it reflects the TSOs' best estimates at the end of 2020, with data for both time horizons.

The technical and economical parameters that are a part of the model include:

1. For thermal power plants (TPPs)

- General data (plant name, number of units, fuel type)
- Operational status for each unit
- Maximum net output power per unit
- Minimum net output power per unit
- Heat rates at maximum net output power per unit
- Fuel cost per unit
- Variable O&M costs per unit
- Outage rates (FOR, MOR) and maintenance periods per unit
- CO_2 emissions factor per unit
- Operational constraints (minimum up/down time) per unit
- Must-run constraints per unit

2. For hydro power plants (HPPs)

- General data (plant name, number of units)

- Operational status for each unit
- Plant type (run of river, storage or pumped storage plant)
- Maximum net output power per unit
- Minimum net output power per unit
- Biological minimum production
- Maximum net output power per unit in the case of pumped storage plants
- Minimum net output power per unit in case of pumped storage plants
- Monthly generations for 2 hydrological conditions: average and dry

3. For renewable energy sources (RES)

- Installed capacities (solar)
- Installed capacities (wind)
- Hourly capacity factors

4. For demand

- Annual consumption (TWh)
- Hourly load profiles

5. For network transmission capacity

- NTC (MW)

We modelled the other countries of Europe, outside the EMI region, based on PEMMDB assumptions. The following tables show the installed capacities in all the countries that we modelled.

3.2.4.1 Albania

Albanian power system mostly relies on HPPs. We expect the installed RES capacity to reach a much higher level in the mid-term horizon than in the short-term one.

Table 3.8: Installed capacities per technology – Albania

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal – gas	100	300
Hydro	1912	2949
Wind	80	384
Solar	50	445

3.2.4.2 Bosnia and Herzegovina

Bosnia and Herzegovina relies heavily on lignite TPPs, but the decommissioning process that is due because of environmental circumstances will begin in the period from the short-term horizon and will have some impacts on the mid-term horizon. Also, we expect new HPPs by the mid-term horizon and increases in solar and wind, especially the latter.

Table 3.9: Installed capacities per technology – Bosnia and Herzegovina

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal – lignite	1765	1632
Hydro	2308	2493
Wind	350	580
Solar	50	100

3.2.4.3 Bulgaria

In Bulgaria we expect a significant decrease in TPPs from the short-term to mid-term horizon. The thermal mix in Bulgaria consists of lignite, hard coal and gas, and we expect no lignite to be left by the mid-term horizon. One nuclear plant, NPP Kozlodui, will stay in operation. Solar capacity will almost double from 2025 to 2030, and wind will also rise.

Table 3.10: Installed capacities per technology – Bulgaria

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	6514	4836
Nuclear	2150	2150
Hydro	3207	3207
Wind	749	948
Solar	1785	3216

3.2.4.4 Switzerland

Switzerland does not have any TPPs other than nuclear capacity, which is over 2000 MW in the short-term horizon and a good deal lower in the mid-term horizon. There is also very significant HPP capacity due to the high potential there. There are no large solar plants in Switzerland, and all solar generation is expected from rooftop photovoltaics connected to the distribution grid.

Table 3.11: Installed capacities per technology – Switzerland

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Nuclear	2200	1190
Hydro	14530	14930
Wind	200	300
Solar	0	0

3.2.4.5 The Czech Republic

There is nuclear power in the Czech Republic, while conventional TPPs have the highest installed capacity. RES is also quite present, with solar far exceeding both wind and hydro capacity.

Table 3.12: Installed capacities per technology – Czechia

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Nuclear	5195	5195
Thermal	9409	6690
Hydro	1589.9	1600
Wind	618.75	960
Solar	2305.5	3487

3.2.4.6 Germany

Germany is a large country with a lot of installed capacity, including a large share of variable RES.

Table 3.13: Installed capacities per technology – Germany

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	87876	76106
Hydro	7673	7673
Wind	75027	95921
Solar	25241	36171

3.2.4.7 France

In France, nuclear capacity is predominant, with also vast hydro installed capacity and quite a lot of new wind and solar expected, while conventional thermal is also present, but in the smallest amount.

Table 3.14: Installed capacities per technology – France

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Nuclear	68229	65578
Thermal	8918	8558
Hydro	25203	25511
Wind	26595	41489
Solar	18455	43796

3.2.4.8 Croatia

Croatia has significant hydro potential and over 3000 MW of installed HPPs. Most TPPs are run on gas, with all the remaining fuel oil plants expected to be decommissioned by the short-term horizon, and a little under 300 MW of coal TPPs. Wind and solar are expected to increase modestly from the short-term to the mid-term horizon.

Table 3.15: Installed capacities per technology – Croatia

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	981	981
Hydro	3117	3117
Wind	1000	1300
Solar	400	600

3.2.4.9 Greece

Greece currently has a large TPP fleet using ignite, gas and fuel oil. While some fuel oil is expected to remain in operation (277 MW), in the modeled target years most of the thermal capacity will be in gas plants. Greece also has abundant hydro potential, as well as RES potential that is now being exploited, and which will increase in the modeled horizon.

Table 3.16: Installed capacities per technology – Greece

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	7886	7768
Hydro	5525	4545
Wind	5100	7000
Solar	5200	7700

3.2.4.10 Italy

Italy has conventional thermal, hydro, wind and solar installed capacity, with thermal in the first place according to shares in 2025, whereas we expect RES to take the first position by 2030.

Table 3.17: Installed capacities per technology – Italy

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	42146	41557
Hydro	19169	19229
Wind	15956	19300
Solar	28299	51120

3.2.4.11 Kosovo

TPPs in Kosovo is based on lignite, and they will be decommissioned in the future due to environmental impacts, but not during the modeling horizon. Beside the Kosovo B and Kosova E Re TPPs, there is some HPP capacity, and wind and solar will significantly increase from the short-term to mid-term horizon.

Table 3.18: Installed capacities per technology – Kosovo

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	978	978
Hydro	434	434
Wind	184	336
Solar	70	150

3.2.4.12 Montenegro

Montenegro has one TPP, Pljevlja and a large fleet of storage HPPs. Wind capacity is not expected to increase through the mid-term horizon, while solar will increase by five times.

Table 3.19: Installed capacities per technology – Montenegro

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal - lignite	225	225
Hydro	1117	1117
Wind	243	243
Solar	50	250

3.2.4.13 Poland

Poland is amongst the European countries with the largest share of conventional TPPs. It also has some nuclear capacity, plus hydro, wind and solar, of which we expect the largest increase in wind.

Table 3.20: Installed capacities per technology – Poland

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Nuclear	4400	4400
Thermal	32940	32433
Hydro	1006	1006
Wind	9661	14563
Solar	5114	5114

3.2.4.14 Romania

Romania is a large county with significant RES potential, including hydro, wind and solar, and the capacity of all three will increase to the mid-term horizon, especially solar. There is also a mix of TPP capacity, consisting of lignite, gas and hard coal plants which will reach over 10 GW in the mid-term horizon. There is one nuclear plant, Cernavoda, with almost 2000 MW of installed capacity.

Table 3.21: Installed capacities per technology – Romania

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	7185	10055
Nuclear	1965	1965
Hydro	6693	6784
Wind	4334	5255
Solar	3393	5054
Biomass	137	137

3.2.4.15 Serbia

Serbian thermal capacity is based mostly on lignite, and the installed capacity will decrease by a 1000 MW from the short-term to mid-term horizon. HPPs will remain the same, and wind and solar will increase somewhat between the time horizons (from a starting point of about 400 MW today).

Table 3.22: Installed capacities per technology – Serbia

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	5889	4829
Hydro	3291	3291
Wind	3900	4553
Solar	468	508

3.2.4.16 Slovenia

There is one nuclear plant, Krško, 703 MW, on Slovenian territory, shared with Croatia. For modeling, it is part of the Slovenian system. There is also over 1000 MW of TPP capacity, mostly gas. The HPP fleet has run-of-river, storage and pump storage plants. The largest increase is expected in solar.

Table 3.23: Installed capacities per technology – Slovenia

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Thermal	1464	1757
Nuclear	703	703
Hydro	1195	1295
Wind	67	150
Solar	951	1866

3.2.4.17 Slovakia

In Slovakia, the largest capacity comes from nuclear, followed by TPPs and HPPs in similar amounts. Wind and solar are amongst the lowest compared to countries of similar size, with the highest increase expected in solar.

Table 3.24: Installed capacities per technology – Slovakia

Technology	Installed capacity (MW)	
	Short-term horizon	Mid-term horizon
Nuclear	2674	2674
Thermal	1832	1832
Hydro	1776	1889
Wind	248	495
Solar	861	1188

3.2.5 NTC values

In the electricity market simulations, the cross-border network capacities between areas are labeled Net Transfer Capacities (NTC) values. By definition, the NTC value is the maximum total exchange capacity (in MW) between two interconnected power systems that is available for commercial purposes in a given period, and a specified direction of active power flow. The NTC is determined using the following formula:

$$NTC = TTC - TRM$$

Where:

Total Transfer Capacity (TTC) is the maximum total exchange program (in MW) between two interconnected power systems that will meet the security standards established by those systems for a certain period and direction of active power flow.

Transmission Reliability Margin (TRM) is the security margin that accounts for uncertainties in the computed TTC values.

Future NTC values are inputs for this study, and are subject to many uncertainties, including internal network development, internal generation units commitments, realization of new cross-border interconnection capacities, demand growth, and more. They also can vary by season (e.g., winter/autumn and spring/summer).

MEPSO provide the NTC values for North Macedonia, and for other countries, the TSOs provided them for the EMI 2021 decarbonization study. Due to the mentioned uncertainties, NTC values are regularly updated and submitted to ENTSO-E. TSOs on both sides of the border determine and mutually harmonize the NTC values.

We used available transmission capacities for the borders equal to the NTCs, and considered this capacity fully available for commercial exchanges during the calculation period.

The NTCs we used in the model are in the Table below.

Table 3.25: NTCs for the short-term horizon

Border	NTC (MW)	
	Direct	Indirect
AL - MK	500	500
MK - AL	500	500
MK - GR	850	850
GR - MK	1100	1100
BG - MK	500	500
MK - BG	400	400
XK - MK	350	350
MK - XK	330	330
RS - MK	300	300
MK - RS	270	270
AT - CH	1200	1200
AT - DE	5400	5400
AT - HU	800	800
AT - IT	660	490
AT - SI	950	950
AL - GR	400	400
AL - ME	450	450
AL - XK	650	500
BA - HR	1200	1200
BA - ME	800	750
BA - RS	1100	1200
BG - GR	1700	1400
BG - RO	2600	2600
BG - RS	800	800
CH - DE	4000	2600
CH - FR	1400	3700
CH - IT	3910	1910
CZ - DE	2100	1500
CZ - PL	900	1200

Border	NTC (MW)	
	Direct	Indirect
CZ - SK	1378	1600
DE - FR	3000	3000
DE - PL	2000	3000
FR - IT	4195	2160
GR - IT	1180	785
HR - HU	1700	1700
HR - RS	500	500
HR - SI	2000	2000
HU - RO	1300	1400
HU - RS	1000	1000
HU - SI	1200	1200
HU - SK	3013	2300
HU - UA	450	450
IT - ME	3500	4670
IT - SI	1400	1155
MD - RO	600	600
MD - UA	800	400
ME - RS	600	600
ME - XK	300	300
PL - SK	1281	1318
RO - RS	2000	2000
RO - UA	200	200
RS - XK	300	400

Table 3.26: NTCs for the mid-term horizon

Border	NTC (MW) Direct	NTC (MW) Indirect
AL - MK	500	500
MK - AL	500	500
MK - GR	850	850
GR - MK	1100	1100
BG - MK	500	500
MK - BG	400	400
XK - MK	350	350
MK - XK	330	330
RS - MK	300	300
MK - RS	270	270
MK - RS	270	270
AT - CH	1200	1200
AT - DE	5400	5400
AT - HU	800	800
AT - IT	660	490
AT - SI	950	950
AL - GR	400	400
AL - ME	450	450
AL - XK	650	500
BA - HR	1200	1200
BA - ME	800	750
BA - RS	1100	1200
BG - GR	1700	1400
BG - RO	2600	2600
BG - RS	800	800
CH - DE	4000	2600
CH - FR	1400	3700
CH - IT	3910	1910
CZ - DE	2100	1500

Border	NTC (MW) Direct	NTC (MW) Indirect
CZ - PL	900	1200
CZ - SK	1378	1600
DE - FR	3000	3000
DE - PL	2000	3000
FR - IT	4195	2160
GR - IT	1180	785
HR - HU	1700	1700
HR - RS	500	500
HR - SI	2000	2000
HU - RO	1300	1400
HU - RS	1000	1000
HU - SI	1200	1200
HU - SK	3013	2300
HU - UA	450	450
IT - ME	3500	4670
IT - SI	1400	1155
MD - RO	600	600
MD - UA	800	400
ME - RS	600	600
ME - XK	300	300
PL - SK	1281	1318
RO - RS	2000	2000
RO - UA	200	200
RS - XK	300	400

3.2.6 Forced and maintenance outage profiles

Forced and maintenance outages are an important input since they can significantly impact available generation capacity. Maintenance profiles are a deterministic input since we know when most generators plan to conduct maintenance on existing TPPs, and forced outages are a probabilistic input since they occur at unexpected times. Forced outage rates represent the probability of a power plant is out of service unexpectedly for a period of time. ENTSO-E's Ten Year Network Development

Plans typically contain data on both forced and maintenance outage rates for different types of TPPs. We randomly generate outages in ANTARES using the time series generator, taking into account outage rates and the mean time to repair, i.e., the duration of an outage.

3.2.7 Value of Lost Load (VoLL)

The model sets a Value of Lost Load (VoLL), which defines the price at which the demand would be unserved if there is not enough capacity in the system to cover it all. The model minimizes the Energy Not Served as VoLL, which is always set higher than other available capacity in the system. In this model, the VoLL value was set based on ENTSO-E recommendations that are also in line with market rules on wholesale markets throughout Europe.

The VoLL is set to represent the maximum price cap and floor set for the wholesale markets in European countries. This price is set to 15000 EUR/MWh, which was the cap at the time we did the modelling for this study, and this is a default assumption in the ERAA 2021.

3.2.8 Flexibility means

We conducted a flexibility assessment as part of this study, as explained further in Chapter 4.4. In case we detect flexibility problems, there are several means to provide flexibility to the system. Those options include:

- **Generation units**: while all generation units are flexible to a point, not all can respond quickly and not all can operate in a flexible manner. For example, nuclear power plants are operated as baseload units, and it takes them quite some time to alter their generation. Since there are no nuclear power plants in North Macedonia, they are not options for providing flexibility in any case. However, most other conventional thermal units can modify their output in an acceptable time frame, the quickest being gas-fueled thermal plants. The exception is combined heat and power units, since they operate depending on heat demand. Also, RES units can modify their generation downward to some extent, by decreasing their output if necessary.

- **Demand-side management**: DSM can provide flexibility by modifying demand based on reacting to explicit signals, including price. However, this is still a novel concept in many countries, especially in SEE. Implementing DSM would require a change in customer behavior, market operation and technology that would require time and programs to adopt.

- **Electricity storage**: storage technologies are among the best options when it comes to flexibility, since they can store energy and convert it to electricity when necessary. Several technologies exist, but in the Macedonian power system, only a single pumped storage HPP is planned in the medium term. However, a flexibility analysis such as this one might give answers regarding the need for additional storage technologies (such as batteries) that could provide greater flexibility to the Macedonian power system.

- **Interconnections:** transmission capacities can provide flexibility from neighboring countries by means of intra-day/day ahead/balancing markets, depending on which are in place, and depends on the availability of transmission capacity. While North Macedonia is generally well connected to its neighbors, balancing markets are still in development and not operating in most of Europe.

  Prior to the passing the new Energy Law in 2018, MEPSO was responsible for all market functions as a transmission system operator and electricity system operator, including auctions of transmission capacities, procurement of balancing services, imbalance settlement, invoicing of energy from renewable sources and forecast of the production from the renewable sources, etc.

  According to the Energy law and the Balancing mechanism, MEPSO is responsible for controlling and organizing the Balancing electricity market by procuring balancing services in the form of FCR, aFRR, mFRR and RR provided by the BSPs. Currently in the Republic of North Macedonia, there are two balance service providers qualified for providing aFRR and mFRR balancing services, and those are AD ESM Skopje, the largest state-owned production company, and the company for production of electricity and heat, TE-TO AD. The power market is under development.

Flexibility covers several timeframes, from intra-hourly to seasonal. While most sources can provide flexibility in several timeframes, their technical and economic characteristics usually make them more suited for a more restricted range. Some of the most important technical characteristics include the energy and power capacity of the sources, ramping up/down limits, response time and charging/discharging time and conversion efficiency.

3.3 Geographic Perimeter of the Analysis

Since this type of thorough analysis takes into account the impact of energy flows from all countries that can affect unsupplied energy, it is important to expand the perimeter of this analysis beyond South-East Europe. This is because of the nature of the analysis, in which resource adequacy includes the potential for supplies as well as different national strategies and trends on RES development that can spill the potential national adequacy problems all over the region/continent from other countries. To develop satisfactory and credible results for the resource adequacy of the Macedonian power system, we significantly broadened the scope of the model to internally take almost all European countries into account. They are shown in more detail in Figure 3.1.

Figure 3.1: Modelled perimeter

Since this vast perimeter still does not encompass all of Europe, we modelled the remaining markets to do so. The external markets in question and the European countries omitted from the model are quite far from North Macedonia and it was estimated based on previous knowledge acquired by the Consultant that modelling them into more detail would not have a meaningful impact on the accuracy of the model. This was also judged to be the case for Turkey because of its geographical form (most of it being in Asia) and distance from North Macedonia. We chose this approach to modelling such countries since it continues to represent the potential imports and exports to and from those countries each hour, which is the main impact they might have on the Macedonian power system, while not modelling their generation fleet in full detail.

These external markets included the Western Europe energy market connected to France; the Northern Europe energy market connected to Germany and Poland; and Turkey, which is connected to Bulgaria and Greece.

4 METHODOLOGY

The methodology for this report closely follows the Methodology for European Resource Adequacy Assessment (ERAA) that ACER published at the end of 2020. The ERAA methodology is still in development, and ACER does not fully describe some of the requirements. The least explanation is available for the EVA, for which in some steps expert evaluation is used and is explained further in Chapter 4.3.

4.1 Economic dispatch model

4.1.1 Market model description

We used ANTARES, an electricity market simulator developed by RTE, to perform simulations for this assessment. ANTARES calculates the optimal unit commitment and generation dispatch from an economical perspective. Its objective function is to minimize the total system generation costs while also respecting the technical constraints of the generation units that have been set in the model. The dispatchable generation (TPPs, HPPs, and storage facilities) and the resulting cross-border market exchanges constitute the decision variables of the optimization problem.

ANTARES is a sequential Monte Carlo simulator designed for short to long-term studies related to large, interconnected power grids. ANTARES simulates the economic behavior of a power system on an hourly basis. The ENTSO-E model made for analyzing the European resource adequacy assessment has also been built in ANTARES.

To create annual scenarios, ANTARES can be provided with ready-made time series or generate those through a given set of parameters. Based on this input data, several Monte Carlo years are developed through the association of different time series. This is done randomly, or the user sets them. Then, the model assesses the supply-demand balance for each hour of the simulated year by subtracting wind and solar generation from the load (their generation profile is set by time series), managing hydro energy with a heuristic approach, and optimizing dispatch and unit-commitment of thermal generation clusters and storage. The main goal of this process is to minimize the total cost of generation in all interconnected areas.

ANTARES assumes that all the electricity is sold and bought on an hourly basis with perfect knowledge of future RES generation and consumption. Also, we assume perfect weekly foresight for renewable generation, consumption, and unit availability, which means that the model optimizes storage, hydro reservoirs, and thermal dispatch, i.e., dispatchable generation. This differs from reality, where forecasting deviations and unexpected unit and interconnection outages can happen and the system needs to cover them.

We adjust for such differences by using the ERAA methodology, which prescribes that we can deduct part of the capacity from the available supply, and add to demand according to the need for reserves in the Macedonian power system. Either approach can be used according to the type of reserve – aFRR should be added to the demand profile and mFRR deducted from the supply side if it is solely given by the storage HPPs, which is the case for the Macedonian power system. ERAA Article 4 (6) says that frequency restoration reserve (FRR) may be deducted from the available capacity resources in the economic dispatch, either by deducting their respective capacities from the available supply or by adding them to the demand profile. In the Macedonian power system, we added 40 MW of aFRR to the demand profile, and deducted 80 MW of mFRR from the supply side of hydro storage power plants (since hydro storage provides mFRR).

In the model, we also assume a perfect market (no market power, bidding strategies, etc.). The model calculates prices based on the marginal cost of each unit/technology while taking into account transmission capacities. The efficiency of each thermal unit is fixed and independent of the unit's loading (in actual operation, the efficiency varies somewhat depending on the generated power).

4.1.2 Input and output of the model

For the market simulation, the Inception Report defines our assumptions for the following inputs:

- hourly consumption profiles for each climate year
- thermal power plants – technical parameters and costs
- hourly generation profiles for RES generation for each climate year
- hydropower plants – type and technical parameters
- storage facilities – type, efficiency, inflows, and reservoir constraints
- net transfer capacities between related areas.

It is also possible to model other technologies, such as demand response or new technologies like *Power-to-grid*, but since these options will not be readily available in the analyzed horizons in the region, they were not presented in the EMI region.

Based on the input provided to the model, market simulations provide the results of the hourly dispatch optimization, which aims to minimize the total cost of operation of the whole simulated perimeter. When we find this optimum cost, we extract the following outputs, among others:

- locational marginal prices based on the market bids
- hourly dispatch of all the units in each country
- imports and exports
- balances in the modelled countries
- emission levels

These output data are not all strictly relevant for a RAA study, since they are mostly market indicators, but are none the less interesting to look at and observe when performing a study that is done in this much detail and the goal is to present the future state of the Macedonian power system as well as the adequacy indicators, which are explained in more detail in Chapter 4.2.1.

4.1.3 Modeling of generation facilities

Data used to build the ANTARES model for this study included the data acquired for the EMI Decarbonization study[1] in 2021, for the power systems of EMI countries. This included detailed data on all generation, loads, RES generation profiles and NTCs from the TSOs for 2025 and 2030. The data for the remaining European countries in the model was taken from the PEMMDB.

We also improved the EMI data to include the remaining climatic years since the ERAA methodology envisions at least 30 climatic years for the adequacy assessment, available in Pan European Climatic Database (PECD), and the EMI study only used three. Therefore, we widened the EMI data on hydropower plants, loads, and renewable energy sources using the PEMMDB/PECD data.

This was done for the load using the following approach – we took load data for the EMI countries from PEMMDB for all 35 climatic years, which is how much is available in the PEMMDB. For hydropower plants, it was more complicated. In the EMI data, there is detailed data on cascades according to the rivers in each country, and HPPs are modeled in several zones in the EMI model according to those cascades. The cascade data is not available in the PEMMDB or in PECD. To maintain this cascade data for the EMI countries, we adapted the PECD inflow data to the cascades by calculating the share of each cascade in the total inflow. We divided the climatic inflow data from PECD into three categories – average, dry and wet - the categories in the EMI data. Then we scaled the shares of each cascade in the total inflow to those three categories to obtain 35 climatic years for all the cascades in the EMI region. **Error! Reference source not found.** shows the process of t his transformation.

[1] Assessment of the Impact of High Levels of Decarbonization and Clean Energy on the Electricity Market and Network Operation in Southeast Europe

Figure 4.1 Example of hydro transformation in the model

We based hourly wind production and solar generation on historical data for these production types. We combined the forecasts of installed capacity for 2025 and 2030 for each country with the historical data to obtain production time series for wind and solar generation.

We modeled thermal generation units with their specific and economic characteristics. Their availability is determined by a probabilistic draw for each Monte Carlo year. Planned outages for the horizons in question also take into account expected outages. This way, we could draw a very high sequence of availabilities for each unit used in the simulations, i.e., outages were taken into account by using the time series generator in 20 possible variations which is a high sequence of possible unavailability’s, as opposed to only using one.

Outside of the EMI region, we modeled generation facilities on the basis of so-called equivalents. We aggregated hydro generation facilities on a run-of-river or reservoir basis, and aggregated thermal power plants according to fuel, efficiency and technology.

NTCs between countries were taken from PEMMDB for the rest of Europe, and HVDC and HVAC lines were aggregated according to the border.

Since a small number of European countries were not in the model scope, we modeled external markets to represent those countries (Scandinavia, the UK, Ireland, Spain, and Portugal). We used prices for these markets from TYNDP 2020 for 2025 and 2030, and created profiles based on historical profiles on Nordpool for the last three years.

4.2 Adequacy methodology

Adequacy studies aim to evaluate a power system's available resources and projected electricity demand to identify supply/demand mismatch risks under a variety of scenarios. In an interconnected system such as SEE, the scope of analysis needs to be wide and include neighboring countries, since the network infrastructure can have a considerable impact on adequacy results.

We followed the ERAA methodology to determine adequacy, including four steps:

1. The definition of Monte Carlo years, as described in the previous chapter,
2. Running the simulations using all the described input data and 1000 Monte Carlo years,
3. Analyzing the results to identify the structural shortage periods, i.e., moments during which electricity production on the market was not sufficient to satisfy electricity demand.

If in the third step the results show any shortage periods which result with the existence of adequacy indicators, options need to be tested regarding added capacity which would be needed to eliminate inadequacy. These options are usually evaluated based on a predefined economic discussed with the Client first.

4.2.1 Adequacy indicators

As previously mentioned, the indicators most relevant for an adequacy study are LOLE and EENS.

Why are these indicators important? The reason is that any positive value for LOLE or EENS indicates that there is a risk that customers may not have adequate supplies of electricity under those conditions. While no power system is 100% reliable, the economy of North Macedonia and all modern economies depends vitally on the reliable and resilient flow of electrons into our devices, homes, businesses, government agencies, hospitals and industries. We are becoming substantially more dependent on electricity over time. This ERAA analysis, and those that MEPSO carries out in the future, need to maximize the protection for customers against shortfalls in the supply of power, subject to cost constraints. That's why this work is so vital.

We now turn to showing how to calculate these indicators, which we do by extracting the following two parameters from the model outputs:

- Loss of load duration (LLD, in hours) – LLD is the period for which resources such as available generation and imports to North Macedonia are insufficient to meet demand for a single Monte Carlo run.
- Energy not served (ENS, in GWh or MWh) – ENS is the sum of the electricity demand which cannot be supplied due to insufficient resources.

From LLD and ENS, we can calculate the following:

- LOLE, in hours – the expected number of hours during which resources are insufficient to meet demand over multiple scenario runs, i.e., Monte Carlo years. LOLE can be calculated as the mathematical average of the respective LLD over the considered model runs:

$$LOLE = \frac{1}{J}\sum_{j=1}^{J} LLD_j;$$

where J is the total number of considered model runs (in our case J=1000) and LLD_j the LLD of *j-th* model run.

- EENS in GWh/MWh – the electricity demand which is expected not to be supplied due to insufficient resources. EENS can be calculated as the mathematical average of the respective ENS over the considered model runs:

$$EENS = \frac{1}{J}\sum_{j=1}^{J} ENS_j;$$

where J is the total number of considered model runs and ENS_j is the ENS of *j-th* model run.

4.2.2 Convergence of results

Article four of the ERRA methodology prescribes that TSOs need to perform a convergence check for the chosen Monte Carlo years. To perform that check, the methodology defines the coefficient of variation with the following equation:

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

where $EENS$ is the expectation estimate of ENS over N number of Monte Carlo samples, i.e.,

$$EENS = \frac{\sum_{i=1}^{N} ENS_i}{N}$$

where i= 1, …, N and $Var\ [ENS]$ is the variance of the expectation estimate, i.e.,

$$Var[EENS_N] = \frac{Var\ [ENS]}{N}$$

A stopping criterion for the probabilistic assessment is enforced, under a sufficiently large number of Monte Carlo years, by comparing the relative increment of α with a given threshold value θ. In particular, for N sufficiently large, if

$$\frac{|\alpha_N - \alpha_{N-1}|}{\alpha_{N-1}} \leq \theta$$

then increasing the number of Monte Carlo years would not increase the level of accuracy considerably. Consequently, the Monte Carlo analysis can stop.

The main criterion for declaring the convergence of results is if no significant changes of α occur past a certain number of Monte Carlo realizations, meaning no significant changes in averaged results are expected and thus no additional Monte Carlo realizations are needed to improve results. In ERAA 2021, no explicit simulation stopping criterium is set for the coefficient of variation. The decision of whether or not to launch additional model runs is based on a compromise between the relative change in α and the required computational time.

4.3 Economic viability assessment (EVA) methodology

EVA presumes an implementation of economic assessment of the likelihood of retirement, mothballing and new build of generation assets. The purpose is to minimize the overall system cost, including operational and investment costs. Only generation resources participating in an energy-only market are assessed. EVA aims to replicate as precisely as possible the actual decision-making process followed by investors and market players. This process is very important for power system development, as well as the final customers, as it puts all new potential investments into the same starting point and evaluates them equally. It also looks into the existing capacities and guides the decision on whether an existing capacity is still viable in the assumed future market and whether additional analysis and thought should be made on that decision. It also helps put into perspective new technologies since it puts them through the same process if there are some plans for such. Implementing a competitive market only generation fleet is the goal of every country going through the ERAA process and will benefit enormously in achieving satisfactory prices for final customers while maintaining security of supply and system reliability.

The ERAA methodology provides two possible solutions for the implementation of EVA, either to assess the viability for each capacity iteratively or by minimizing overall system costs, where all capacities are optimized at once.

4.3.1 Description of the EVA process

The basic principle of this methodology is to replicate investors' and market participants' decision-making process. To do so, we need to define a metric as a so-called breaking point, the level of return required for a project to convince investors that a project is worth investing in. After that point is found, it is still not an absolute incentive for an investment into a new plant. It is rather an indicator for further research and deeper analysis of a potential investment, taking into account the more detailed specifics each individual project might have.

According to the ELIA methodology, this decision is based on the weighted average cost of capital (WACC) and hurdle premium, or a so-called hurdle rate. The hurdle premium is a parameter that makes up for price risks, going beyond the typical factors and risks covered by a standard WACC calculation, that also incorporates risk in its calculation. The inclusion of a hurdle premium is in line with the ERAA methodology, which states in Article 6, paragraph 9 (a) (iii) that "a market conform and transparent increase in the WACC for these target years may be used to account for this price risk; the principles underlying the WACC increase shall be consistent with the WACC calculation guidelines from the CONE[2] methodology". All capacities are subject to the same WACC, while the hurdle premium varies by technology, according to their risks and uncertainties.

Therefore, the decision rule for the viability of an asset is the following:

$$Economically\ viable\ \leftrightarrow E\ [IRR]\ \geq hurdle\ rate,$$

where the hurdle rate is the sum of WACC and hurdle premium, and is the threshold that the expected value of the project internal rate of return needs to equal or exceed for the project to be economically viable.

In order to apply the EVA, we use the adequacy model results in an iterative process. First, we need to identify the EVA candidates. In the Macedonian system, there are TPPs and renewable units, from hydro to solar. The economic viability of some units depends on policy-driven regulations and support schemes. Therefore, we only consider units that depend on energy-only market (EOM) revenues as candidates for commissioning/decommissioning in the EVA process. This is the approach applied in all existing studies that contain EVA calculations.

EOM dependent units would be TPPs, with the proviso that only coal, lignite, and oil TPPs are considered decommissioning candidates, since energy policies in Europe do not allow any further construction of these TPP types. Gas TPPs are both commissioning and decommissioning candidates.

4.3.2 Economic and technical parameters

The parameters used for the implementation of the EVA process are costs connected to each generation unit, i.e., fixed and variable operation costs and CAPEX, economic lifetime, and hurdle rate. The following tables show these details for all technology types that would be included in the EVA, even though for the Macedonian system, only gas power plants are under consideration.

[2] CONE is the Cost of New Entry, which represents the investment cost of a cheapest capacity annualized over the plant lifetime. It reflects technology, location and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, i.e., not unique sites with unusual characteristics.

Table 4.1 Techno-economic parameters for thermal decommissioning candidates in the EVA

Generation unit category	Fixed cost [EUR/kW/y]	Non-fuel Variable O&M [EUR/MWh]	CO2 emission factor [kg/GJ]	Marginal cost in 2025 [EUR/MWh]	Marginal cost in 2030 [EUR/MWh]	Hurdle rate [%]
Hard coal	51	2.4	94	51	74	7
Lignite	65	3	101	47	70	7
Gas CCGT	30	1.9	57	49	79	7
Gas OCGT	20	3.5	57	71	114	8
Gas conventional	20	3.5	57	72	116	8
Light oil	41	2.8	78	167	201	8
Heavy oil	41	2.76	78	126	154	8
Oil shale	41	2.8	100	54	85	8

Table 4.2 Techno-economic parameters for thermal commissioning candidates in the EVA

Generation unit category	CAPEX [EUR/kW]	Fixed cost [EUR/kW/y]	Economic lifetime [y]	Non-fuel Variable O&M [EUR/MWh]	CO2 emission factor [kg/GJ]	Marginal cost in 2025 [EUR/MWh]	Marginal cost in 2030 [EUR/MWh]	Hurdle rate [%]
Gas CCGT	850	30	20	1.9	57	49	79	12
Gas OCGT	500	20	20	3.5	57	71	114	14

Table 4.3 Fuel cost [EUR/GJ]

Fuel type	2025	2030
Nuclear	0.5	0.5
Lignite	1.4	1.4-3.1
Hard coal	2.3	2.5
Natural gas	5.6	8.9
Light oil	12.9	13.8

The inputs of this data are gathered from PEMMDB as well as from the methodology developed for ELIA for the hurdle rate calculation. The WACC included in the hurdle rate is a reference industry-wide WACC calculated in line with the principles with the ERAA methodology and used also in ENTSO-E studies, and it equals 5.53%.

In the future in North Macedonia the relevant authorities must draft a reliability standard as defined in the Directive 2019/944 EU and the adequate drafting methodology.

4.3.3 IRR calculation

The internal rate of return is calculated as part of the EVA methodology to determine if it exceeds the hurdle rate for each project. If the IRR exceeds the hurdle rate, that is an indication that a project is worth looking into and should be researched further by the investor and deeper profitability analysis is performed. If the IRR is lower than the hurdle rate, that is an indication that the project might not be worth looking into and might not be the best option for the certain power system. Also, when looking into decommissioning's, projects with IRRs lower than the hurdle rate should be considered as decommissioning candidates sooner than was planned.

IRR calculation is based on costs, revenues, and the economic life of an asset. The internal rate of return is actually the rate for which the net present value (NPV) of a project equals zero, as follows:

$$NPV = -I + \sum_{t=1}^{K} \frac{IR(t)}{(1+R)^t} = 0$$

where I equal costs, IR presents inframarginal rents and K presents the economic lifetime of the asset:

- Costs I Ɨ mean all fixed costs, including capital investment costs (CAPEX), and fixed operation and maintenance costs (FO&M)
- Inframarginal rents IR are the earnings acquired because of the difference between the project's variable cost and the variable costs of the plant that sets the price in the model
- Economic lifetime of the asset K is the expected period of time during which an asset remains useful to the owner.

4.4 Flexibility methodology

As part of this study, we analyzed the flexibility of the Macedonian power system. Power system flexibility is the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales, or due to other causes such as transmission outages. Flexibility sources can be defined as the technical and non-technical solutions which provide or facilitate the provision of flexibility and help ensure the balancing and proper technical functioning of a power system. Flexibility is an important metric for the power system since a system that is not flexible cannot manage fast changes in either generation or supply and can therefore result in hours of unsupplied energy, as well as problems for system operators, which must manage that uncertainty somehow to provide the customers the best service possible. It is therefore very important also for the final customer which might sense the impact of a system that is not flexible enough through disturbances in energy supply.

Flexibility sources are in particular essential to operate electricity systems with a high number of non-dispatchable power generation units connected to the grid having variable outputs throughout the year. The main purpose of flexibility sources is to contribute to:

- facilitating deployment of intermittent RES
- ensuring system stability and contributing to security of supply while
- minimizing system costs.

4.4.1 Definition of power system flexibility

The flexibility of a power system is the extent to which a power system can modify electricity production or consumption in response to variability. Power systems are faced with multiple types of uncertainty, such as:

- **Uncertainty of demand**: demand is forecast on the basis of assumptions and historical customer behavior, and it varies by time of day, season, etc. However, there are many uncertainties surrounding future demand, as customer behavior may vary from past practice. Demand is predicted on a week-ahead basis, day-ahead, and intra-day basis so that market parties and system operators can schedule their portfolios and manage their operations.
- **Uncertainty of renewable generation**: this variability is becoming more relevant given the rapid increase in renewables throughout Europe. RES generation heavily depends on the weather, and forecast tools can predict variations on a day-ahead and intra-day basis.
- **Unexpected outages of generation units**: forced outages resulting in a sudden loss of power are inevitable, and extremely unpredictable, but must be anticipated.

Shortages in flexibility can result in emergency measures to avoid frequency deviations and preventive or real-time generation curtailment or demand shedding. Flexibility needs have been seen to increase throughout Europe following the increase in renewable generation (e.g., solar photovoltaics) and new demand applications (e.g. electric vehicles).

4.4.2 Scope and objective of the flexibility study

The objective of the flexibility analysis in this ERAA project is to investigate whether the Macedonian power system will have sufficient capability to deal with variations in demand and generation. The focus of this analysis is on both short-term flexibility and long-term variations (daily, and yearly), using the simulations with Monte Carlo years representing the hourly resolution of the power system's operation.

In general, there is no unanimously prescribed flexibility methodology but rather different approaches which have the intention to capture all of flexibility complexity in the power system. Within this report we used methodology based on the Energy Community's *Study on flexibility options to support decarbonization in the Energy Community*[3] which was published during the last phase of this project. The flexibility assessment is based on two main steps.

The first step is focused on the calculations of three different types of flexibility needs – daily, weekly and annual in terms of required energy (GWh or TWh) necessary to balance the power system. These types of flexibility needs are determined based on the residual load. Namely, increased share of variable RES significantly impacts residual load which has to be met by the controllable (flexible) generation assets in the power system. The residual load for the *i-th* hour is calculated as follows:

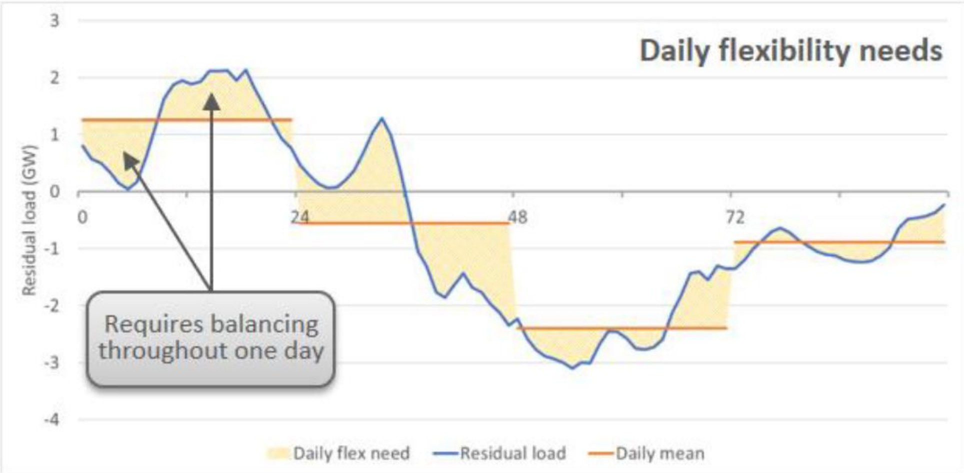
[3] Energy Community, Study on flexibility options to support decarbonization in the Energy Community, Trinomics, Artelys, July 2022

$$Residual\ Load_i = Load_i - WPP_{generation_i} - SPP_{generatio_i} - HydroRoR_{generation_i}$$

The residual load should be calculated for each hour (8760 hours per year) and for each out of 1000 Monte Carlo years.

In order to calculate daily flexibility needs it is necessary for each day to calculate average residual load (based on the 24 values) and then find difference between the average residual load and the corresponding residual load in the given hour of the observed day. The sum of all 24 differences (in absolute terms, negative values are converted to positive) is in fact daily flexibility needed for the observed day. Schematically, the representation of daily flexibility calculation is given on the following figure.

Figure 4.2 Representation of daily flexibility needs



Finally, summing up all 365 values for flexibility needs we obtain daily flexibility needs for one observed Monte Carlo year. It is necessary to apply this process for all analyzed Monte Carlo years.

Analogously, the weekly flexibility needs are calculated for all analyzed Monte Carlo years. The weekly average of residual load is firstly calculated and afterwards the differences between the weekly average and weekly residual loads are determined. Summing up the weekly differences for all 52 weeks, the weekly flexibility need is determined. The same approach is used for annual flexibility needs as well.

The second step is in fact optional, it depends on the results of power system simulations, and this step is done only in the case there is lack of generation capacities in the system, i.e., in the case of situations of Energy Not Served (ENS). In the case of ENS, second step must be done where additional sources of flexibilities (such as batteries, PSHPP, DSM, CCGT…) are taken into account in order to eliminate ENS and consequently to provide enough flexibility to the power system. In such cases, the results of flexibility analysis are in terms of required additional flexible generation capacities in the system. There are two approaches how to determine additional flexible generation capacities in the system – iteratively (running the simulations with different combinations of flexibility means) or by using mathematical model with expansion planning option in order to determine which generation capacities should be built in order to obtain minimum net present value of total system cost.

In order to assess the flexibility of Macedonian power system we used results of the 4 most relevant scenarios in order to address the flexibility of the Macedonian power system. Namely, we analyzed flexibility needs for the following scenarios:

- Base case 2025
- Base case 2030
- High RES 2025
- High RES 2030

Chapter 5 provides a detailed description and results of the flexibility analysis.

5 Results

In this Chapter, we present results of this analysis, for adequacy, EVA and flexibility.

To quantify the required capacity, we made the following inputs and assumptions:

- To keep all generation units that have not officially announced their closure in the system;
- To use the latest RES projections for all time horizons and countries, including wind and PV;
- To assume consumption forecasts with the latest energy efficiency and electrification policies;
- To base imports and exports on net transfer capacities (NTCs);
- To apply detailed generation, demand and other data for almost all European countries, taking into account NTCs and the latest policies and expected changes.

MEPSO chose these scenarios to test whether the Macedonian system would have sufficient power supplies (adequacy) under a wide range of potential future conditions. As a summary of the results, we note that 19 scenarios/sensitivities do not show any unserved energy in North Macedonia for 2025 or 2030. This result is not unexpected, given the high level of connectivity in Southeast Europe (SEE). This finding is also in line with the ENTSO-E study on generation adequacy for all of Europe in 2021 for the same target years, which found no generation adequacy issues for North Macedonia.

Based on this result, we considered other parameters, and what future circumstances, changes and sensitivities in the Macedonian power system could further test the system's adequacy.

To do so, we assessed two sensitivities with limited imports to North Macedonia, in which we restricted imports to 70% of the base case scenario, to cover occurrences in neighboring countries or on interconnections that could limit imports. This scenario produced inadequacies in both 2025 and 2030, as explained below.

5.1 Comparison of scenarios and sensitivities with national impact

Since most of the scenarios/sensitivities did not show an adequacy problem in the Macedonian power system, we have provided other indicators based on the Antares modelling in this chapter. We divide them into conditions that have a national impact, versus those that incorporate the region's impact, and we compare some parameters with the Base case scenario. These results show the generation and generation mix in the scenarios and sensitivities with a national impact, with balances for the Macedonian system, for both the short and medium term (2025 and 2030).

These are the scenarios and sensitivities with **national impact**, using the capital letter V and numbers for easier viewing of the Figures and Tables below:

- **V1 – Base case scenario**

- **V2 – High demand sensitivity**
- **V3 – No new TPPs and HPPs sensitivity**
- **V4 – High RES sensitivity**
- **V5 – Low RES sensitivity**

Figure 5.1 compares the resulting generation mix for all the national impact scenarios and sensitivities in 2025, and the country's position regarding imports. In all of them, the Macedonian power system generates considerably less than its consumption, importing the rest of the necessary energy from neighboring systems. In the third sensitivity (V3), domestic generation is at the lowest point, only reaching less than half of domestic needs, since we assumed no new capacity from power plants at Veles, Gradec and no new gas TPPs.

Figure 5.1 The Generation Mix and Import Levels for North Macedonia Under Alternative Scenarios (2025)

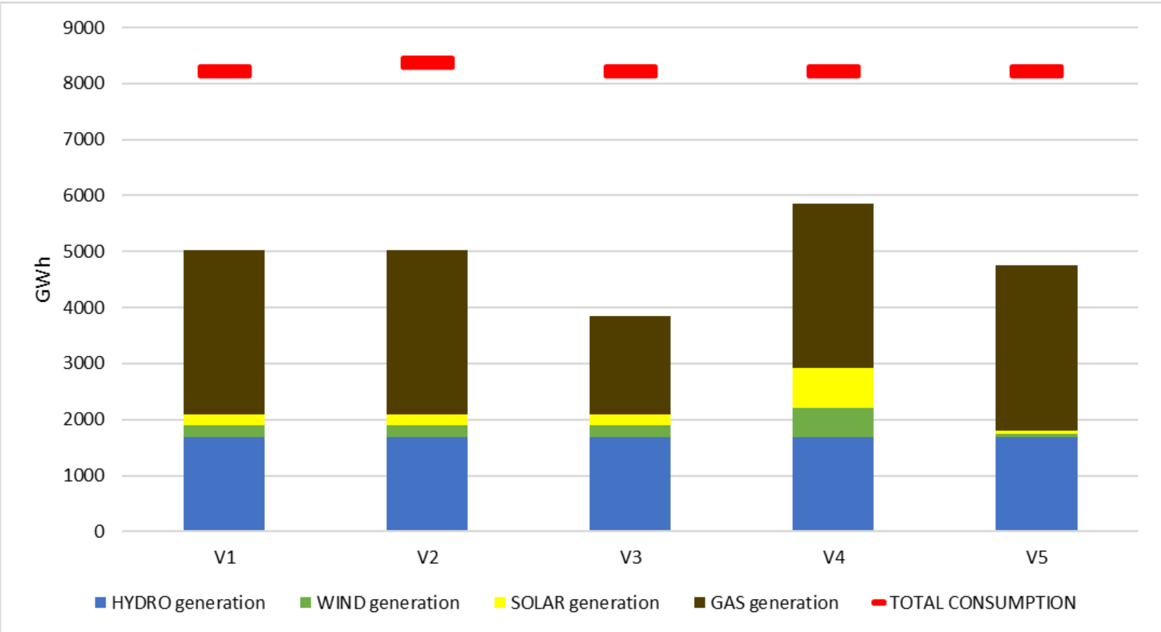


Table 5.1 Balances for national impact scenarios and sensitivities of North Macedonia (2025)

Electricity balance	Consumption (GWh)	Generation (GWh)	Pump load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
V1	8209	5020	0	-5596	2407	-3189
V2	8369	5020	0	-5702	2353	-3349
V3	8209	3839	0	-6380	2010	-4370
V4	8209	5853	0	-5078	2658	-2420
V5	8209	4751	0	-5830	2304	-3526

Table 5.1 shows that the consumption is equal in all scenarios and sensitivities except in the high demand sensitivity, where it is 2% higher, according to MEPSO's assumptions. We based the demand assumptions for 2030 in line with MEPSO's TYNDP 2020, and then scaled them for 2025.

Total generation differs depending on the assumptions in each sensitivity. It is the highest in V4, the High RES sensitivity, and the lowest in V3, when there are no new investments in the generation fleet, i.e. no new TPPs or hydro plants. MEPSO tested these assumptions to assess circumstances that might cause adequacy problems, but the results show that there is no such impact, due to the country's ability to import power.

Table 5.2 Flows on borders (2025; V1)

Base Case	FLOWS on the BORDERS (GWh)															
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**AT**	**SK**	**UA**	**MD**
AL				267			1827	60				283				
BA					2943		4267			540						
BG				5529				2270	12123	697						
GR	976		838					1281								
HR		571				725				366	4474					
HU					3085				1918	2028	2475		2354	2103	386	
ME	631	555								529		268				
MK	1203		8	783						225		187				
RO			12125			4434				5294					248	692
RS		1229	1985		1360	2218	3197	1641	570			1050				
SI					869	64							1656			
XK	1219						1435	344		178						
AT						1906					3186					
SK						9512										
UA						3533			1039							1810
MD									2102						847	

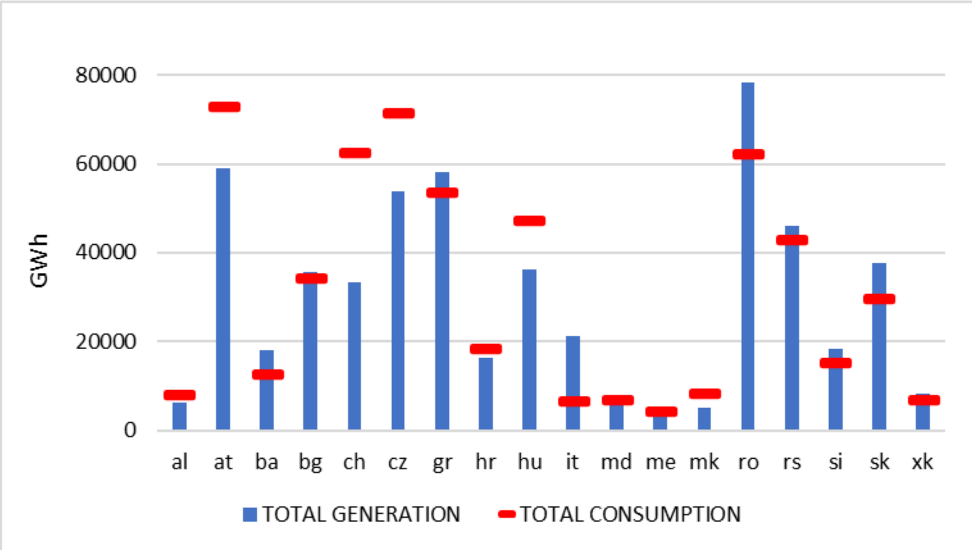
Table 5.2 shows flows on the borders in the region[4]. While the model for this study includes almost all of Europe, we have only shown the countries with the highest impact on the Macedonian power system. This is a major advancement in capturing the dynamics of power flows into and out of SEE, as prior EMI studies represented the dynamics of just a few external markets, usually the Turkish and Central European markets. Here, we modelled all the external countries in more detail, which shows how much of interchange occurs between SEE and Austria, Slovakia, Ukraine and Moldova. We note that exports to these countries can be for transit to other countries. This table shows from where the energy that lacks in the Macedonian power system comes from, i.e. from which countries exactly. This is of course possible and available due to the NTCs available that are shown in more detail in Chapter 3.2.5. To further understand this table, it is important to note that one direction of flows (from row to column) signifies the direction from Macedonian power system to all the others it borders with, while the opposite (column to row) signifies the flow towards Macedonian power system. That would mean that the net interchange for North Macedonia equals (60GWh+2270GWh+1281GWh+1641GWh+344GWh)-

[4] Clarification of directions of flow-AL->GR flow is 267 GWh, while GR->AL is 976 GWh, i.e., the direction of the flow from Albania to Greece is row to column and the opposite direction (Greece to Albania) is from column to row

(1203GWh+8GWh+783GWh+225GWh+187GWh). I.e., that means that the flow from North Macedonia to Albania is 1203 GWh, while the flow in the opposite direction is 60 GWh (same for all other countries and other tables that show flows and congestions in this report).

Error! Reference source not found. shows the balance of generation and consumption for the m odeled European countries in the Base case scenario, except for France, Germany and Poland which are much larger systems that rely mostly on themselves, as is example for France which is among the most influential exporters of energy. Germany on the other hand is highly dependent on imports.

Figure 5.2 Generation and consumption of the modeled countries (2025; V1)



In Figure 5.3, we compare the national impact scenarios in 2030 for North Macedonia. In 2030, consumption is higher, and to meet that increase, there is new hydro capacity from HPPs Veles and Grades, new pumped storage plant Cebren, and RES increases (see details in the Appendix).

Figure 5.3 Generation mix and import levels of North Macedonia under alternative scenarios (2030)

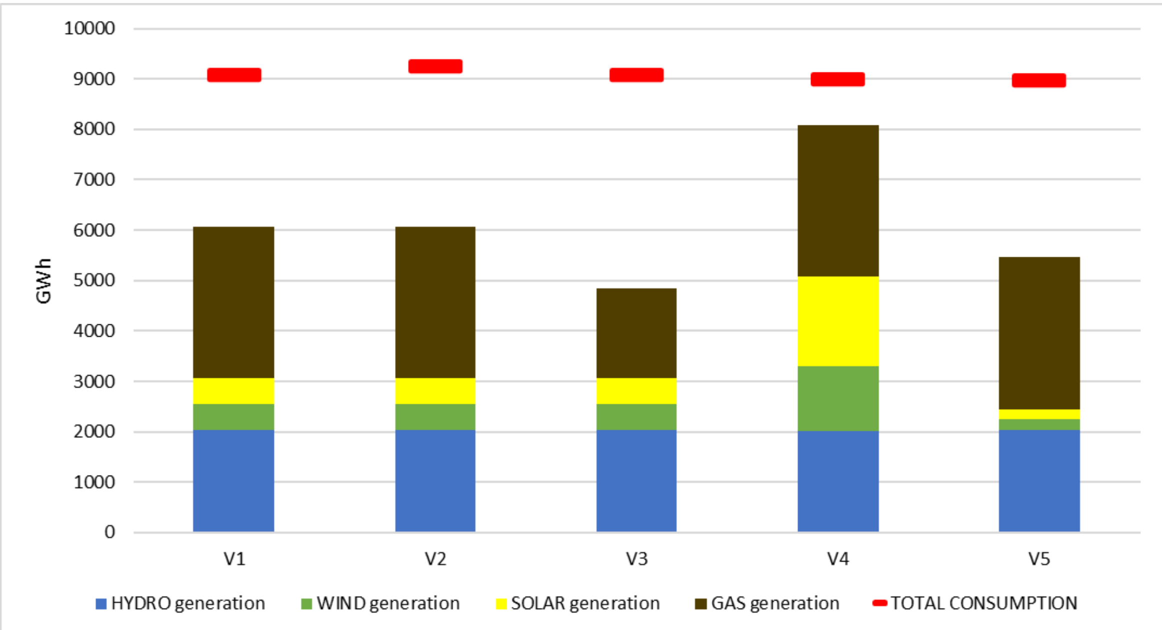


Table 5.3 Balances for national impact scenarios and sensitivities of North Macedonia (2030)

Electricity balance	Consumption (GWh)	Generation (GWh)	Pumped load (GWh)	Customer load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
V1	9067	6333	331	8736	-5278	2544	-2734
V2	9240	6335	333	8908	-5395	2489	-2905
V3	9076	5119	340	8736	-6124	2167	-3956
V4	8977	8279	241	8736	-4619	3921	-699
V5	8963	5642	227	8736	-9372	4109	-5264

In 2030 there is pumped load at PSHPP Cebren, so consumption in Table 5.3 refers to the total consumption from adding the customer load (demand) and pumped load, less energy not supplied if it existed. Customer load is a predefined hourly input time series of demand. Pumped load values change in the scenarios based on the operation of pumped storage HPPs in pumping mode. Generation in this table refers to the total generation from adding the output of all modelled plants. Curtailed generation would not be included if it existed, which it does not for the Macedonian power system in these scenarios.

Table 5.3 therefore shows balances for the five national impact scenarios and sensitivities for 2030, showing that North Macedonia is a significant net importer in each case except for V4. In V5 the level of import dependence rises to nearly 59%, or three-fifths of the consumption, while in V3 it is 44%. **This raises the question of how dependent on imports North Macedonia chooses to be**. Consumption is larger than customer load in 2030 due to the pumped load needs for PSHPP Cebren, while generation is in general larger due to new wind, solar and hydro capacity.

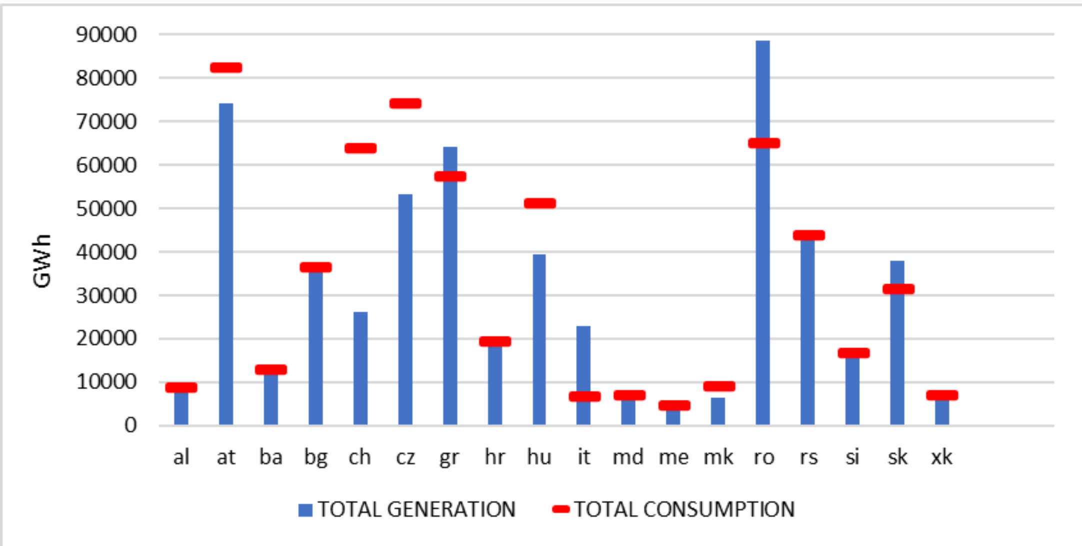
Table 5.4 shows flows on the European borders, again for the Base case scenario, for 2030. As in 2025, the highest flow is on the Hungarian borders, in line with its position in the center of Europe. On the other end of the spectrum, the lowest flows are on the Kosovo borders, as it is the smallest country in the region. In general, the flows are higher in 2030 than in 2025, in line with the increase of the demand and generation fleets in all countries.

Table 5.4 Flows on borders (2030; V1)

Base Case	FLOWS on the BORDERS (GWh)															
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**AT**	**SK**	**UA**	**MD**
AL				22			1417	105				846				
BA					3672		2171			23						
BG				1386				1071	7523	1994						
GR	1590	0	3564					3404		0						
HR		718				2558				59	4972					
HU					1849				329	828	1617		1795	5809	929	0
ME	861	1965								1311		533				
MK	778		250	66						967		482				
RO			7643			7080				8594					813	2362
RS		4117	529		2220	3935	2262	616	26			432				
SI					856	273							1930			
XK	387						1024	82		708						
AT						1324					1927					
SK						4402										
UA						2377			451							837
MD									827						2574	

Error! Reference source not found. shows that the relationship of generation to consumption d oes not change in the five years from 2025 to 2030, though the total amounts are higher.

Figure 5.4 Generation and consumption of all the modeled countries (2030; V1)



5.2 Comparison of sensitivities with regional impact

In this Chapter, we analyze the remaining sensitivities, those that are regional, and which also did not show adequacy issues for North Macedonia:

- **V6 – Decarbonization sensitivity**
- **V7 – CO_2 sensitivity**
- **V8 – Fast RES pace sensitivity**

We tested these sensitivities, in contrast to the ones in Chapter 5.1, on the basis of the entire region, i.e., **assumptions were varied not just for the Macedonian power system, but for the entire region**. These include sensitivities connected to emissions and environmental influences on power systems, i.e., a higher level of decarbonization for all countries in the region, in line with the moderate decarbonization scenario in the EMI 2021 study (reducing coal and lignite generation by about 2/3 by 2030), and a change of CO_2 prices. For the sensitivities where we varied the CO_2 price, we did not expect it would impact the adequacy of the Macedonian power system, since that is a market parameter. However, due to the current geo-political situation for electricity and fuel prices and fuel scarcity, we included such sensitivities to more fully encompass future possibilities.

Along with these sensitivities, we carried out additional sensitivities for faster RES development in the entire region, in line with the fast pace in Greece's plans, to test how such an increase would impact the Macedonian power system.

It is important to note that, as for the scenarios and sensitivities in Chapter 5.1, **none of these sensitivities resulted in adequacy issues**. However, we have reported selected market impacts based on this complex modeling.

Figure 5.5 Generation mix of North Macedonia (2025)

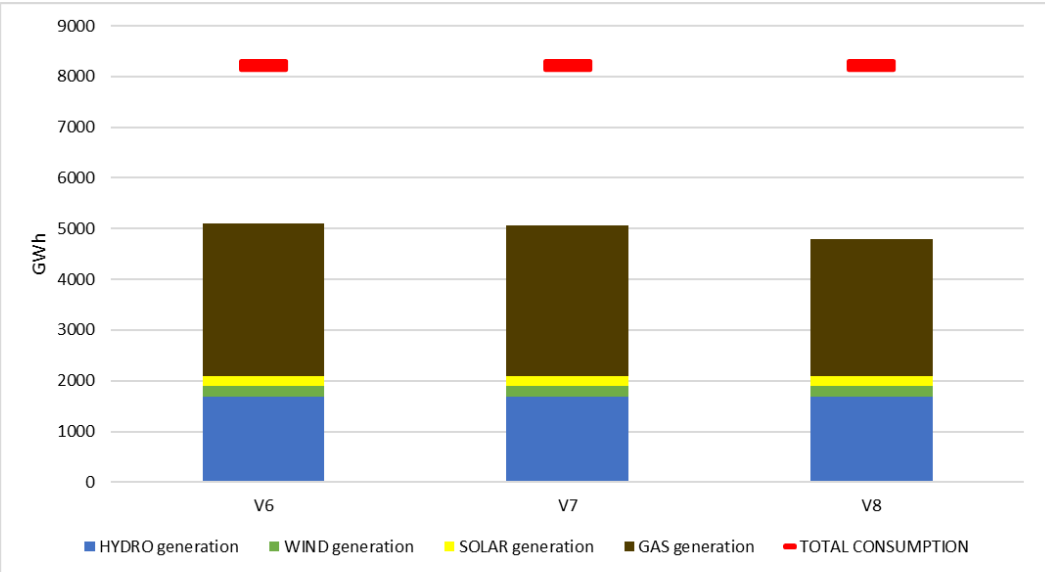


Figure 5.5 shows the Macedonian generation mix for the regional impact sensitivities. While the amount and the mix of generation is similar to the Base case scenario in V6 and V7, in V8 Macedonian

generation decreases slightly, because the significant regional RES increase impacts the marginal price, making imports more economical than generation from the Macedonian thermal power fleet.

Table 5.5 shows the Macedonian balance for the regional sensitivities for 2025, indicating that the net interchange is slightly lower than in the national impact scenarios and sensitivities.

Table 5.5 Balance for regional impact sensitivities of North Macedonia (2025)

Electricity balance	Consumption (GWh)	Generation (GWh)	Pump load (GWh)	Customer load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
V6	8209	5111	0	8209	-5233	2137	-3096
V7	8209	5062	0	8209	-5054	1910	-3145
V8	8209	4798	0	8209	-6874	3463	-3411

In Table 5.6, we use V7 as an example of the regional results, since a change in CO_2 price is the most likely to occur by 2025, though the exact levels are unknown.

Table 5.6 Balances in the region (2025; V7)

Electricity balance	Consumption (GWh)	Generation (GWh)	Pump load (GWh)	Customer load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
AL	7862	6281	0	7862	3585	2005	-1579
BA	12586	16786	118	12469	2093	6290	4197
BG	34292	33982	248	34044	13645	5502	-8144
GR	53663	61943	104	53559	3490	4925	1435
HR	18462	17287	616	17846	6906	5730	-1176
ME	4117	3845	0	4117	7989	2910	-5078
MK	8209	5111	0	8209	5233	2137	-3096
RO	62067	72615	0	62067	6872	18435	11562
RS	42816	40345	364	42453	11537	9132	-2405
SI	15200	14325	300	14900	11943	1639	-10304
XK	6922	5095	119	6803	3049	1160	-1889

In the higher CO_2 price sensitivity, countries with a large thermal fleet generate less, such as Bosnia and Herzegovina, Romania, and Serbia, while others increase their generation slightly, mostly from storage hydro plants. However, the impact on the Macedonian power system is not very large – there is a slight decrease of TPP generation. This indicates that a higher CO_2 price (whether due to the implementation of CBAM or the ETS price) will not materially affect North Macedonia in 2025.

Further, we evaluated the flows on each border for V6, and provide the percentage loading for each border in Table 5.7 and Table 5.8, to provide insights on interconnection utilization. Cross-border loadings are calculated by dividing the total energy that has passed through a line in a certain direction with the number of hours and the NTC of that line. That is why it is referred to as the insight of the line utilization. In Table 5.7, for example, we project that the flows between North Macedonia and Albania in 2025 will be 1101 GWh under this sensitivity, and the flows in the other direction will be just 50 GWh. In Table 5.8 the loadings in red show high flows i.e., above 50%, while the cells in green show low flows i.e., below 10%. It is noteworthy that the loadings are the highest in the rest of the Europe, while in SEE they are satisfactory and even low. This confirms the high level of grid connections in SEE. The loadings on the Macedonian borders are also quite low, with higher loadings on the Serbian border.

Table 5.7 Flows on borders (2025; V6)

Base Case	FLOWS on the BORDERS (GWh)															
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	AT	SK	UA	MD
AL				53			1219	50				683				
BA					1725		3560			1006						
BG				3233				1706	6	557						
GR	1346		1599					1980								
HR		968				286				793	3683					
HU					3813				2741	3308	3818		1613	965	298	
ME	835	726								801		548				
MK	1101		40	204						239		553				
RO			10407			2670				4834					142	381
RS		399	1599		652	1024	2424	1426	344			1264				
SI					716	38							885			
XK	303						786	71								
AT						2619					4442					
SK						12351										
UA						3921			1212							2110
MD									2568						571	

Table 5.8 Loading on borders (2025; V6)

V6	Loading (%)															
	AL	**BA**	**BG**	**GR**	**HR**	**HU**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**	**AT**	**SK**	**UA**	**MD**
AL				2			46	1				5				
BA					16		51			10						
BG				22				24	0	8						
GR	39		13					21								
HR		9				2				18	21					
HU					26				24	38	36		23	4	8	
ME	21	11								15		21				
MK	13		1	3						7		19				
RO			46			22				28					8	
RS		4	23		15	12	46	41	2			48				
SI					4	0							11			
XK	7						30	2		2						
AT						37					54					
SK					62											
UA						69			69							60
MD															8	

When observing differences among different market areas, the important factors are operating indicators, for which we present the simulation results for 2025 in Table 5.9. We determine the market price using the marginal cost of generation and price in neighboring markets. For example, we anticipate in 2025 that the marginal price for North Macedonia will be among the lowest in the region at 63.81 Euros per MWh, and that CO2 emissions costs will be 26 million Euros. These calculations are based on variable costs including fuel, CO_2 and O&M costs of all generating units.

Table 5.9 Operating indicators (2025; V6)

	AL	**BA**	**BG**	**GR**	**HR**	**ME**	**MK**	**RO**	**RS**	**SI**	**XK**
Total operating costs (mil. €)	1.2	377.9	125.7	2200.9	242.8	67.7	152.0	1421.7	1186.9	18.5	169.2
Total generation (GWh)	6281	16786	33982	61943	17287	3845	5111	72615	40345	14325	5095
CO_2 emissions (mil. tonne)	0	14.6	7.7	14.5	1.7	1.6	0.9	12.6	28.2	3.1	4.1
CO_2 emissions costs (mil. €)	0.2	393	208	392	47	43	26	341	761	84	112
Marginal Price (€/MWh)	63.82	66.12	63.64	63.60	67.42	71.91	63.81	63.41	66.13	67.94	64.61

The indicators previously shown for 2025 are shown also for 2030 below, including Figures 5.6 and Table 5.10 to Table 5.14. Figure 5.6 shows the generation mix for the regional impact sensitivities which differ very slightly, since the greatest regional impact results from changing the adequacy indicators.

Figure 5.6 Generation mix and level of imports for North Macedonia under alternative scenarios (2030)

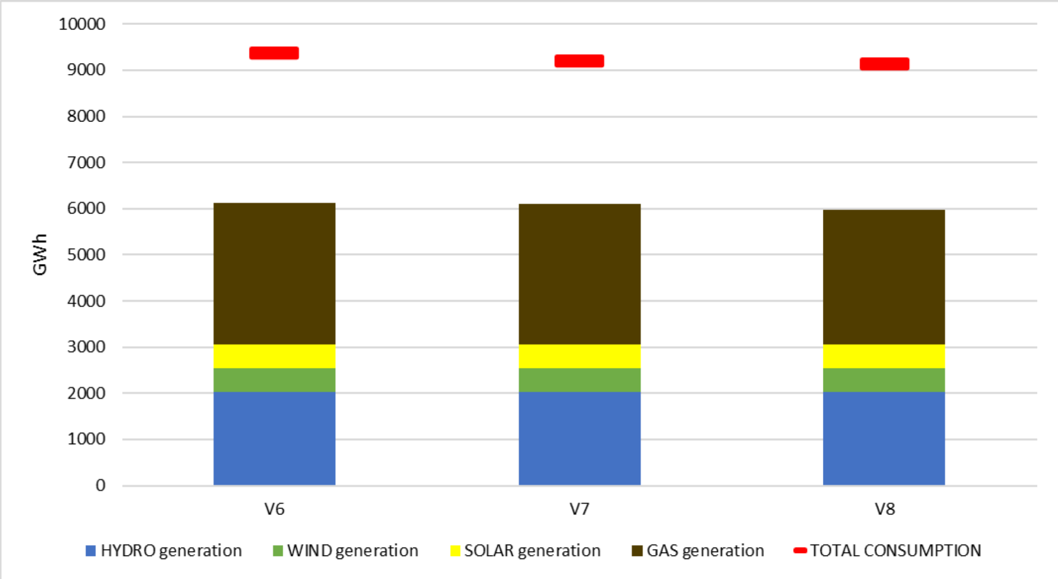


Table 5.10 shows the Macedonian balance for these sensitivities, showing that net imports are lower than in 2025, since in these sensitivities the emission parameters prominently change.

Table 5.10 Balance for regional impact sensitivities of North Macedonia (2030)

Electricity balance	Consumption (GWh)	Generation (GWh)	Pump load (GWh)	Customer load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
V6	9365	6632	630	8736	-5665	2934	-2731
V7	9181	6464	446	8736	-5786	3071	-2715
V8	9118	6283	382	8736	-5248	2413	-2835

Table 5.11 shows the balance in the region for V7, which is not changed in terms of net importers and net exporters.

Table 5.11 Balance in the region (2030; V7)

Electricity balance	Consumption (GWh)	Generation (GWh)	Pump load (GWh)	Customer load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
AL	8680	7456	0	8680	3541	2319	-1223
BA	12916	9736	288	12628	7139	3962	-3177
BG	36381	37573	162	36219	11026	4419	-6607
GR	57328	64258	149	57180	832	11124	10292
HR	19440	19427	952	18488	7725	7710	-15
ME	4546	4865	0	4546	3244	6806	3562
MK	9181	6464	0	9181	5786	3071	-2715
RO	65126	87425	0	65126	1699	24983	23284
RS	44019	38898	444	43575	15919	11651	-4267
SI	16840	15040	503	16336	6224	4354	-1871
XK	6888	5022	85	6803	3353	639	-2714

We show the flows and loadings on the borders in Table 5.12 and Table 5.13. The loadings for North Macedonia are low and quite manageable in 2030 in this sensitivity. The flows on Macedonian borders are the highest from Greece and to Serbia, which shows a large amount of energy in this scenario is imported from Greece. Loadings follow the same pattern.

Table 5.12 Flows on borders (2030; V7)

Base Case	FLOWS on the BORDERS (GWh)															
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	AT	SK	UA	MD
AL				40			833	175				1271				
BA					3079		829			54						
BG				767				758	288	2606						
GR	1759		4960					4405								
HR		661				3005				129	3916					
HU					1256				272	796	766		1650	7327	1005	
ME	1218	2820								1825		942				
MK	442		470	25						1351		782				
RO			5298			7251				9158					828	2449
RS		3659	298		1942	3874	1108	405	9			357				
SI					1449	800							2105			
XK	122						473	44								
AT						1272					1542					
SK						3052										
UA						2238			437							857
MD									694						2433	

Table 5.13 Loading on borders (2030; V7)

V6	Loading (%)															
	AL	BA	BG	GR	HR	HU	ME	MK	RO	RS	SI	XK	AT	SK	UA	MD
AL				1			46	1				5				
BA					29		12			1						
BG				5				11	1	37						
GR	50		41					46								
HR		6				20				3	22					
HU					8				2	9	7		24	28	26	
ME	31	43								35		36				
MK	5		7	0						39		27				
RO			23			59				52					47	
RS		35	4		44	44	21	12	0			14				
SI					8	8							25			
XK	3						18	1		24						
AT						18					19					
SK					15											
UA						39			25							60
MD															35	

Table 5.14 Operating indicators (2030; V6)

	AL	BA	BG	GR	HR	ME	MK	RO	RS	SI	XK
Total operating costs (mil. €)	2.4	460.0	513.0	2420.0	269.4	98.0	168.8	2381.7	1776.1	44.7	230.2
Total generation (GWh)	7478	12580	31714	67454	19501	5083	6633	84300	40034	12108	4486
CO_2 emissions (mil. tonne)	0.0	7.0	3.3	13.6	1.5	1.4	1.0	13.7	25.9	0.5	3.4
CO_2 emissions costs (mil. €)	0.3	190	88	367	41	39	26	369	699	14	93
Marginal Price (€/MWh)	74.66	91.29	74.73	72.96	102.11	98.02	74.66	74.6	90.42	109.21	78.87

Operating indicators in the region are shown in Table 5.14 for V6, and it is clear that the prices are significantly higher than in 2025, primarily due to changes in CO_2 costs., and the prices in North Macedonia remain among the lowest in the region.

5.3 Sensitivity with limited import

We evaluated sensitivities with limited imports as a stress test for the Macedonian power system – since all the other tested variations did not result in adequacy issues, though we assessed many scenarios and sensitivities. The Consultant and MEPSO thus agreed to make additional tests to fully determine the potential impacts of imports on adequacy. Therefore, **we added one sensitivity (hereafter noted as V9) in which import were limited to 70% of net import achieved in the Base case scenario (V1).** This is in line with scenarios made in other. This assumption was also made when carefully analyzing the results of the previously mentioned scenarios and it was noticed that one of the main characteristics of the Macedonian power system is that it is a net importer, relying significantly on power imports from its neighbors even in scenarios with higher installed capacity. Therefore, it seemed necessary to test how a disruption in a smooth transition of electricity from its neighbors could impact the adequacy.

Restricted imports to North Macedonia could arise under several plausible conditions, the most likely being that those countries have challenges in operating their generation fleet, whether due to drought, to lack of gas supplies, to challenges in the coal supply and operation for lignite plants, to nuclear plant forced outages, or a combination of them all. Further, consumption could rise sharply due to a switch to electric heating in the next several winters, and rise steadily in the longer term due to more electric vehicles. Some of this increase in consumption and load could be managed through demand response and demand-side management. Also, larger countries in the region, particularly Greece, have traditionally been significant power importers, but current plans for changing their generation mix show that they could well become a large source of exports to North Macedonia. If Greece does not change its generation fleet as rapidly as its plans suggest, then it would have less available for export, and North Macedonia needs to ensure that such power exports are available to ensure the reliability of customer supplies.

These stresses on the system could materially reduce the ability of those countries to export as much as the grid will allow to North Macedonia, and we recommend that MEPSO and regulators there take this prospect into account in their planning.

Convergence of results

First, to be in line with the ERAA methodology, we calculated the convergence of results for the sensitivity in which unserved energy is present. According to the formulas in 4.2.2, we calculated the Alpha coefficient, and determined the convergence criterion.

Figure 5.7: Alpha coefficient

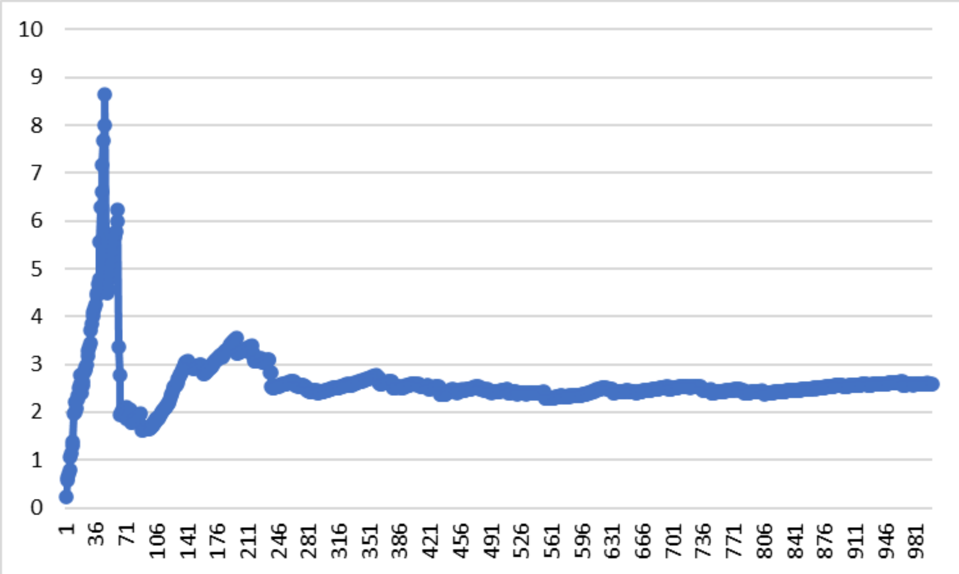
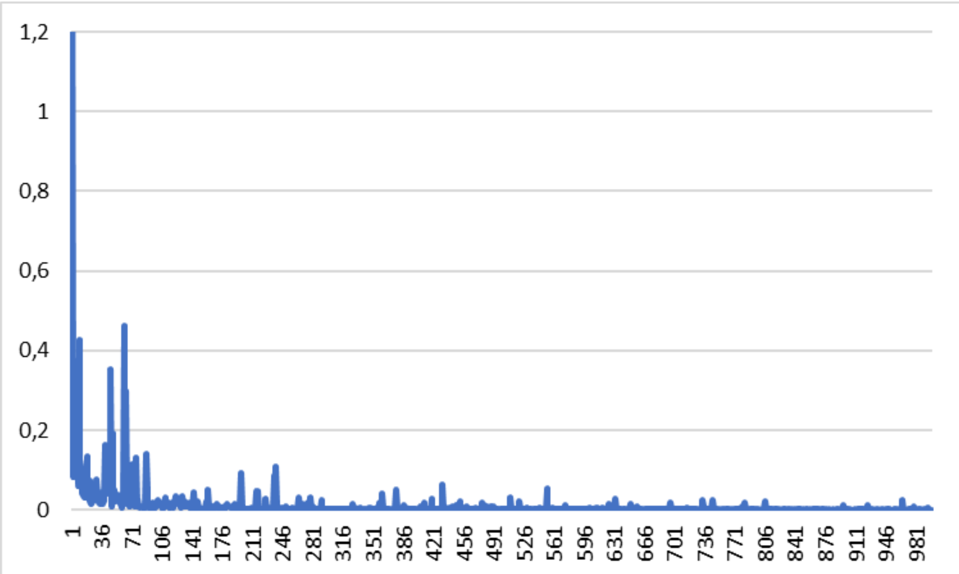


Figure 5.8: Convergence criterion



If no changes are present in the Alpha coefficient after a number of Monte Carlo years, as in Figure 5.7**Error! Reference source not found.**, there are sufficient Monte Carlo years to have confidence in the results of the runs. Figures 5.7 and 5.8 show that there is convergence of results towards the end, and that the chosen figure of **1000 Monte Carlo years** is more than enough to capture the possible future states and inadequacies in the model, and thus satisfies the ERAA regulation.

According to the ERAA methodology it is necessary to calculate EENS and LOLE, expected energy not served and expected loss of load. These are two of the most important parameters of ERAA analysis, since they indicate the extent to which there will be customers not supplied with electricity, and for how long. Both EENS and LOLE are unacceptable above a minimal amount, since there will be personal hardship, economic damage, and strong emotions if the system does not provide reliable power. Under this sensitivity, Table 5.15 shows the expected levels of EENS and LOLE.

Table 5.15 Adequacy Indicators for North Macedonia, Limited Import Sensitivity

	LOLE (h)	EENS (GWh)
V9	3801	911.32

Table 5.15 shows the amount of adequacy indicators for the Macedonian sensitivity with limited imports, which are over 911 GWh of EENS and almost 4000 hours of LOLE. It is highly unlikely that a situation would arise to cause such a low level of imports to be available to the Macedonian power system, but it nevertheless shows the importance of imports for North Macedonia.

Table 5.16 compares the balances between the Base case scenario and limited import sensitivity on the balances in the Macedonian power system. The net interchange falls based on the assumptions, and generation within Macedonia rises slightly to come to terms with the constraint.

Table 5.16 Comparison of Base case scenario with limited import sensitivity

Electricity balance	Consumption (GWh)	Generation (GWh)	Pump load (GWh)	Customer load (GWh)	Imports (GWh)	Exports (GWh)	Net interchange (GWh)
V1	8209	5020	0	8209	-5596	2407	-3189
V9	8207	5703	0	8207	-4529	2937	-1592

Table 5.17 shows the operating indicators in North Macedonia in the sensitivity with limited imports. The impact of unserved energy is greatest on the price and the cost of energy not served, given that no other scenario or sensitivity had unserved energy. In addition to its economic disruptions, if this gap is not filled, EENS is extremely costly.

Table 5.17: Operating indicators (2025; V9)

	Total operating costs (mil. €)	Total generation (GWh)	CO_2 emissions (mil. tonne)	CO_2 emissions costs (mil. €)	Average operating costs (€/MWh)	Price (€/MWh)	ENS costs (mil. €)
V9	198.7	5703.1	1.3	34	28.9	10621.94	13669.7

Under this sensitivity, we tested Macedonia's dependence on imports, which is significant. It is clear that if imports were endangered, there would need to be additional adequacy measures. **Because its cost (over 13 billion Euros) and impacts (more than 10% of the hours without power) would be so substantial, we recommend that North Macedonia closely monitor the possibility of import restrictions (this winter will provide insights on this front), and consider contingency plans (such as CRMs) to take this potential future into account in the next resource adequacy analysis.** At this time, we make no suggestions on construction of additional power plants.

5.4 Base case scenario with Capacity Remuneration Mechanism (CRM)

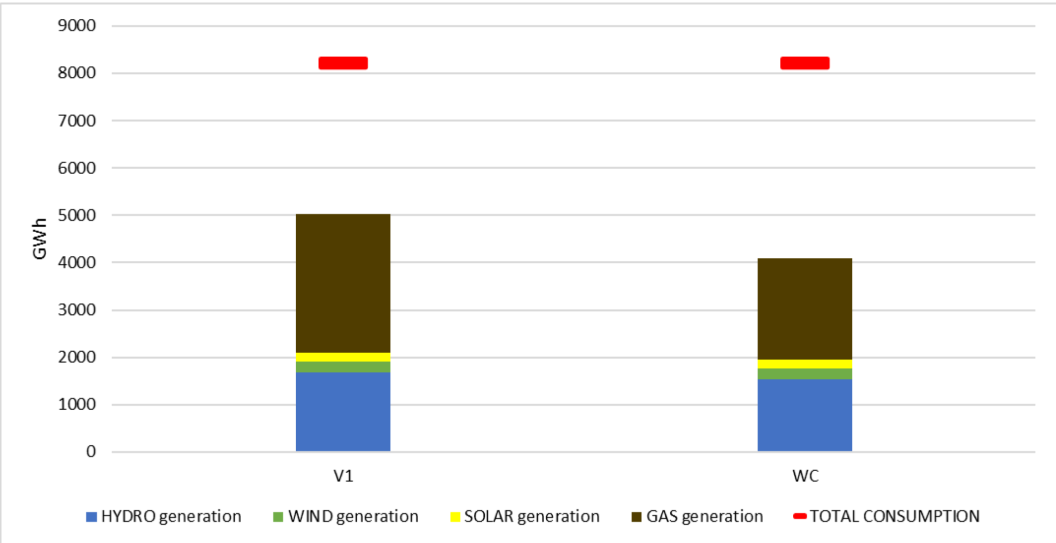
We also agreed to run an additional scenario with CRM additions. The assumptions for this scenario were explained in Chapter 3.2.2. Since only Bulgaria and Greece have plans for CRMs, and only in the form of strategic reserve, we removed the generation capacities responding to those strategic reserves. This does not affect the results of the market simulations, as these strategic reserves are dispatched after the market has depleted all of its in-the-market resources and de facto reaches the price cap, which would not impact the flows or market prices. **For future analysis, we recommend the application of CRM for North Macedonia if there is a serious adequacy issue in the Base case scenario, or if decision makers determine that the prospect of import restrictions is sufficient to merit such measures.**

5.5 Winter crisis scenario

As is explained in the Scenarios and data chapter, we developed this sensitivity to capture the impacts that the global energy crisis of 2022 might have on the Macedonian power system in 2025.

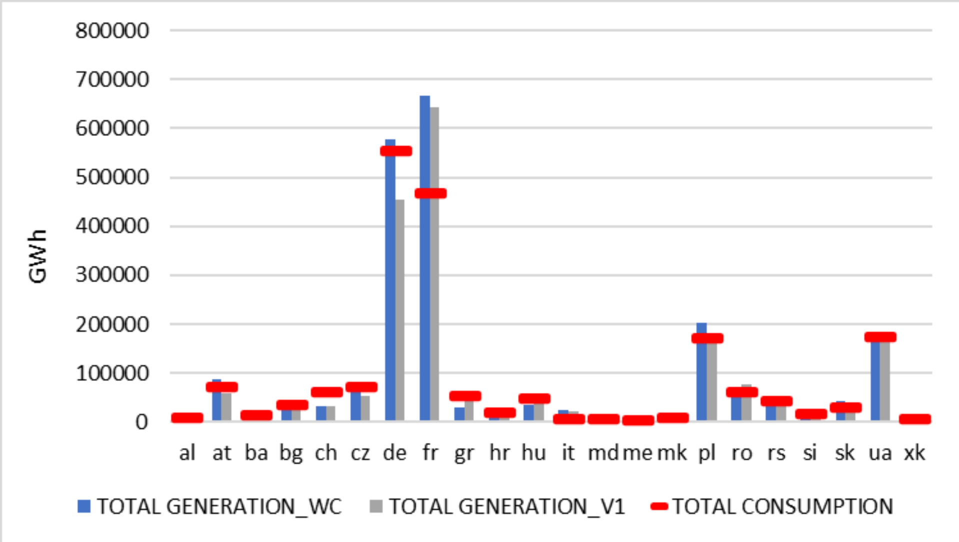
After careful modelling of this sensitivity in line with the assumptions, which would put the power system under some stress, we found no inadequacy in the results of this sensitivity. This result is highly satisfactory since it does assume the most recent data and assumptions available at the time of this report. The following Figure compares the Base Case scenario with the Winter Crisis scenario. It shows that the generation mix of North Macedonia is decreased due to the limited availability of thermal power plants, with imports making up more than half of expected consumption.

Figure 5.9: Comparison of the generation mix of North Macedonia (Base Case vs. Winter Crisis) in 2025



Many European countries change their generation in this scenario, which is to be expected with such a significant decrease of thermal capacity, in combination with dry hydrology.

Figure 5.10: Generation and consumption of all the modeled countries in the Winter Crisis scenario in 2025



The general goal of this scenario was to test whether this difficult global situation would affect the Macedonian power system, and the answer is that no customers would be left without power in 2025, with the assumptions that have been made, even though it is a difficult future to predict. **We recommend that in future resource assessments, North Macedonia continue to test scenarios of restrictions on fuel and generation in SEE and beyond, since those conditions could well affect the availability of power for export to North Macedonia, and that the country be prepared with contingency action plans.**

5.6 Comparison of general indicators

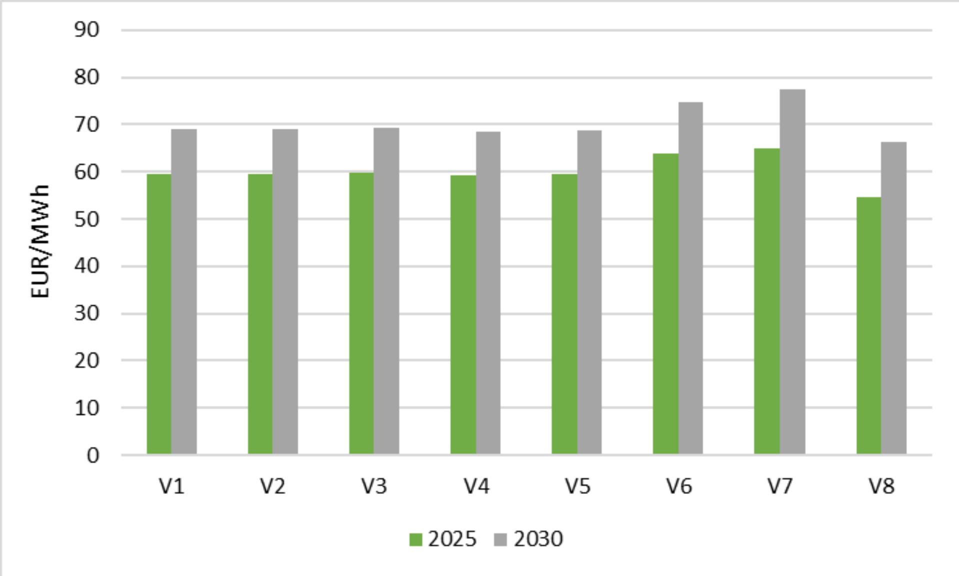
While in the previous chapters we separated the scenarios according to their impact on the Macedonian power system or on the region, in this chapter we compare all scenarios.

Figure 5.11 compares marginal prices for all scenarios in both time horizons. The lowest transmission level marginal price occurs when the entire region follows the Greek RES pace (V8), i.e., when there is a significantly faster increase in RES than the Base case scenario (V1).

The highest marginal price is the scenario with the CO_2 sensitivity (V7), which causes the entire thermal fleet of Europe to become more expensive, and thus raises marginal prices. We expected such marginal prices, which coincide with TYNDP projections.

However, at the time of this report, a global energy crisis is underway, which in the past few months has distorted electricity prices on wholesale markets, leading to prices at the moment that are several times higher than these projected levels, for a host of reasons. This has led to significant actions on the EU and individual country levels. While this situation could not have been expected when our analysis was underway, **we recommend that North Macedonia take such high prices and their impact on the entire electricity system into account in the next resource adequacy study if such conditions and prices persist.**

Figure 5.11 Marginal prices in North Macedonia in 2025 and 2030



In Figures 5.12 and 5.13, we present the generation mix for North Macedonia in both time horizons. In-country generation is at its highest in the High RES scenario (V4), and its lowest in the No new TPPs and HPPs (V3). In 2030 total consumption differs because of a difference in pumped load. In all scenarios, North Macedonia depends on imports, though in 2030, V4 has a narrow gap. **Depending on how North Macedonia considers the risk of imports, it is clear that by 2030, adding more RES to the mix can significantly lower such dependence.**

Figure 5.12 Generation mix of North Macedonia in 2025

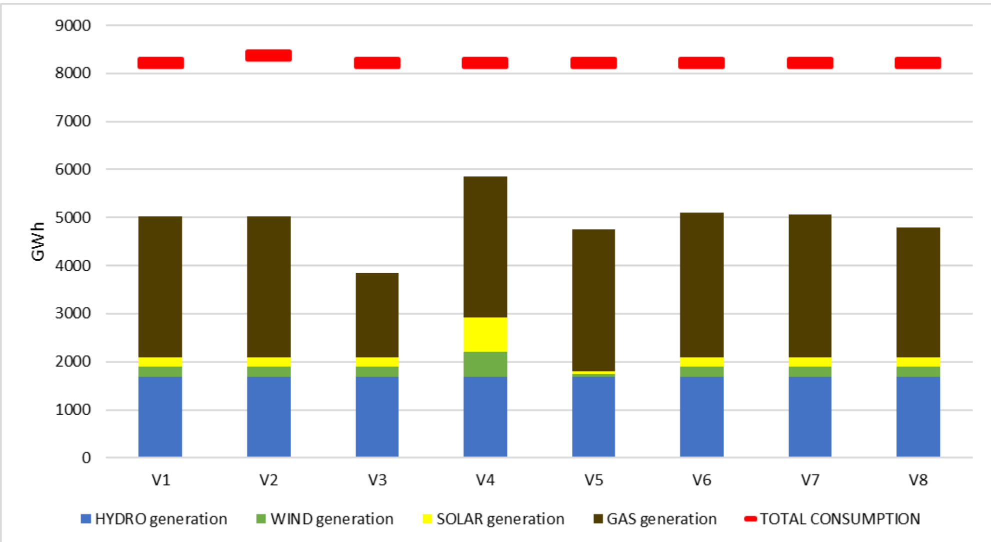
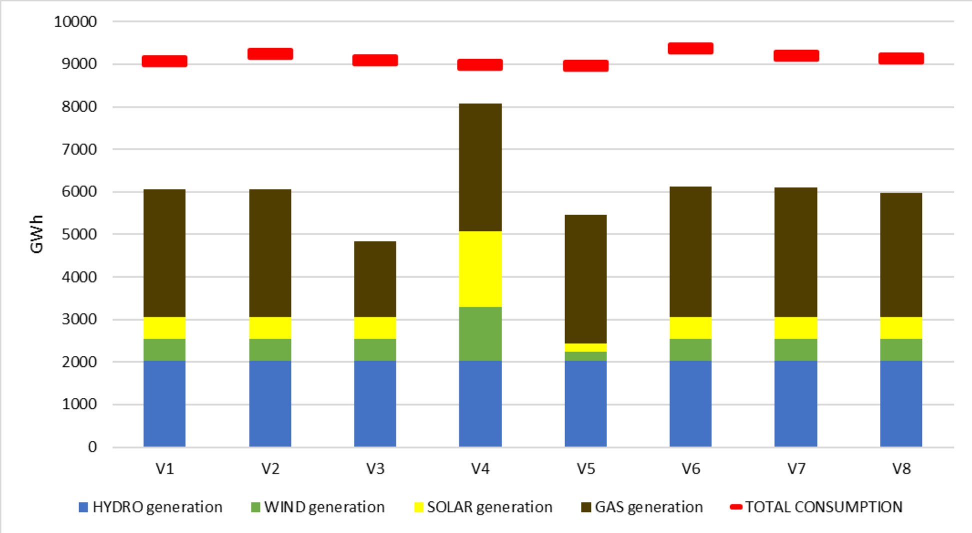


Figure 5.13 Generation mix of North Macedonia in 2030



5.7 Economic viability assessment (EVA)

As explained above, EVA is designed to replicate an investor's and the market's decision-making process by evaluating whether a particular project will meet the threshold for the internal or hurdle rate of return required to support undertaking the project, including an appropriate weighted average cost of capital (WACC).

We carried out an EVA in this case for the thermal capacity, as also explained in Chapter 4. That capacity includes the TE-TO power plant, a new Gas TPP, and the Kogel and Kogel Elem power plants, as well as the generation options for fulfilling the inadequacy gap in the scenario with limited imports. We provide the operating capacity details of these plants in Table 5.18 below. In the ERAA methodology the EVA is envisioned for 2025, taking into account the lifetime of the project.

Table 5.18 EVA candidates

Name of plant	Fuel type	Pmax (MW)	Pmin (MW)
TE-TO	CCGT new	250	6
New gas TPP	CCGT new	141	42.3
Kogel	Conventional gas old 1	30	2
Kogel Elem	Conventional gas old 1	30	9
TPP Gap	CCGT new	400	60

We provided the economic parameters necessary for the calculation of IRR in Chapter 4.3.2.

We performed this calculation using overnight build costs that would occur two years prior to the power plant's operation and assumed the plans would operate for 35 years, as a conservative calculation. Table 5.19 shows the results of the IRR for all these plants.

For the existing TPPs, EVA is part of the decommissioning decision. For TE-TO, the results are positive, indicating that that plant is economically viable. With regard to the hourly results of TPP operation, TE-TO operates the most, and Kogel and Kogel Elem the least, which makes sense given that they are smaller gas plants, with higher operating costs. For that reason, Kogel and Kogel Elem are not economically viable, and the IRR is negative and thus not calculable.

The new gas TPP is a commissioning candidate, with a positive IRR compared to the hurdle rate, which makes it economically viable.

Table 5.19 IRR for EVA candidates

Name of plant	IRR (%)	Hurdle rate (%)
TE-TO	10	7
New gas TPP	9	7
Kogel	N/A	8
Kogel Elem	N/A	8
TPP Gap	12	12

TPP Gap would fill the ENS gap in the limited import scenario. If required, our EVA demonstrates that it would be economically viable, even more so than the other EVA candidates, and its IRR exceeds the hurdle rate. Thus, three of the five candidates proved to be viable in this analysis.

The full EVA process is not simple, and performing it in an iterative manner, as other studies have suggested, would be computationally demanding, beyond anything that has been done before (and beyond the scoe of this study). Also, it would be important to undertake a full generation expansion process to optimally decide on new capacities. Nevertheless, this Chapter indicates the future direction that we recommend that North Macedonia should take, considering the EVA analysis when performing the RAA, both to be fully compliant with ERAA, and most importantly, to achieve meaningful results for both MEPSO and for final customers.

This report recommends that this procedure be continued and improved upon in the next versions of ERAA. **If adequacy issues arise in the future, whether due to potential import limits or other conditions, we recommend that MEPSO and other parties undertake a separate expansion planning process, with multiple generation candidates, to identify the most economic solution for the Macedonian power system.**

5.8 Flexibility analysis results

Whether the power system is sufficiently flexible is based on the currently installed means of flexibility, and the analysis should determine whether additional measures are needed to provide needed flexibility (e.g., through imposing minimum technical requirements on new capacity). Given the changes and variability taking place in the mix of generation (e.g., more RES), and on the demand side, and with new technologies (e.g., storage), we expect the Macedonian needs for flexibility will rise over time.

Determining flexibility needs generally focuses on calculating the residual load, i.e., load from which the non-dispatchable generation is subtracted, including RES generation (wind, solar) and run-of-river hydro, to determine if there would be sufficient resources if this generation were unavailable.

These are the generation units which can provide flexibility in the Macedonian power system:

- TPP Kogel (Nominal capacity 30 MW),
- TPP Kogel Elem Unit 1 (Nominal capacity 15 MW),
- TPP Kogel Elem Unit 2 (Nominal capacity 15 MW),
- TPP Small Gas (Nominal capacity 27 MW),
- Storage HPPs on the river Kozjak (Nominal capacity 88 MW),
- Storage HPPs on the river Globocica (Nominal capacity 126 MW),
- Storage HPPs on the river Vrutok (Nominal capacity 172 MW),
- Storage HPPs on the river Tikves (Nominal capacity 116 MW),
- Pumped Storage HPP on the river Cebren (Nominal capacity 333 MW, pumping capacity 347 MW).

Based on the flexibility methodology in chapter 4.4, we calculate three types of flexibility needs – daily, weekly and annual. This flexibility needs calculation is a part of the first step of flexibility methodology. The second step, as also explained in Chapter 4, is optional. i.e., it depends on the simulation results related to ENS. Since in our observed scenarios there is no ENS, there was no need to perform second step, i.e., to analyze which additional flexibility means should be built in order to meet flexibility requirements. The flexibility assessment was therefore done just through the first step of proposed methodology.

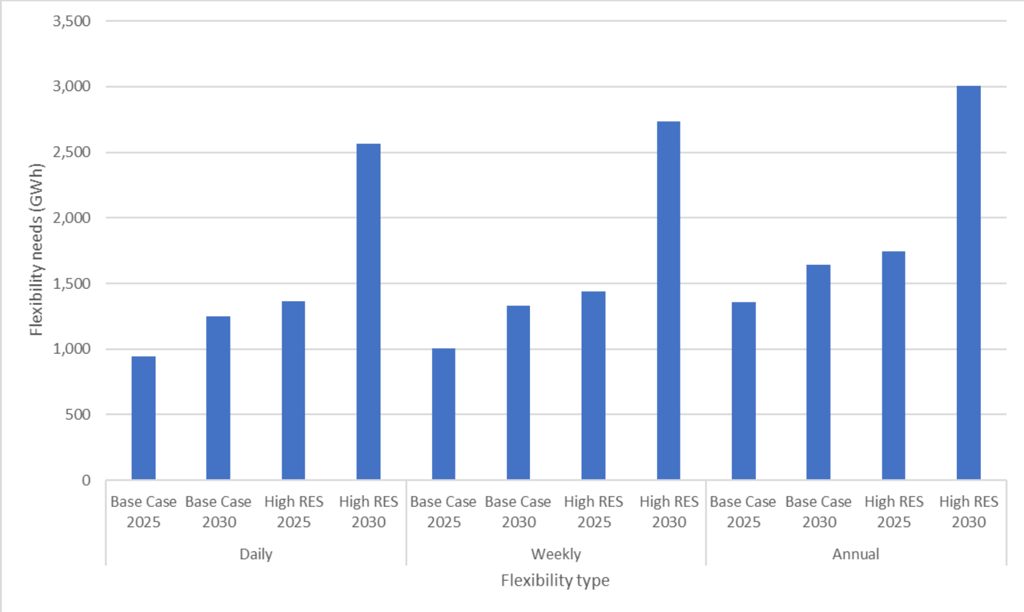
The following table gives results for the flexibility needs for four analyzed scenarios for different types of flexibility. We present the results statistically (e.g., average, max, min), since for each scenario, we have 1000 different datasets available.

Table 5.20 Statistical flexibility needs in North Macedonia based on 1000 Monte Carlo years

Flexibility type	Scenario	Unit	Average	Max Value	Min Value	Stand. Deviation
Daily	BaseCase 2025	GWh	946	973	924	8.05
	BaseCase 2030	GWh	1,247	1,301	1,205	15.88
	High RES 2025	GWh	1,362	1,448	936	78.98
	High RES 2030	GWh	2,563	2,777	1,231	236.10
Weekly	BaseCase 2025	GWh	1,003	1,045	972	13.81
	BaseCase 2030	GWh	1,332	1,395	1,275	22.22
	High RES 2025	GWh	1,438	1,521	988	73.65
	High RES 2030	GWh	2,734	2,965	1,321	226.05
Annual	BaseCase 2025	GWh	1,356	1,499	1,200	49.89
	BaseCase 2030	GWh	1,645	1,814	1,518	48.75
	High RES 2025	GWh	1,743	1,927	1,288	75.10
	High RES 2030	GWh	3,005	3,320	1,618	216.18

As expected, flexibility are lowest in the Base Case 2025 scenario since this scenario foresees the lowest level of RES integration and generation (around 0.4 TWh/y). The highest level of required flexibility is needed in High RES 2030 scenario since the RES generation hits over 3 TWh. The average values of flexibility needs are depicted on the following figure as well.

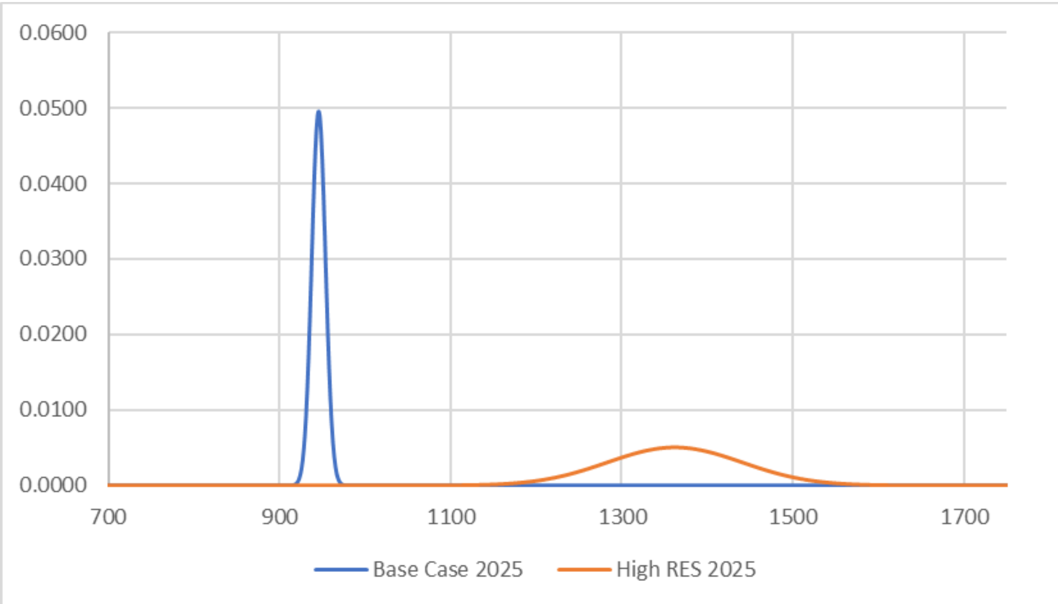
Figure 5.14 Average flexibility needs for the four observed scenarios



We note that with the increase in RES generation, the increase in daily and weekly flexibility needs is greater than the increase in annual flexibility needs. This is due to RES seasonality, where more SPP generation is expected in the summer, while more generation from WPPs is expected in winter.

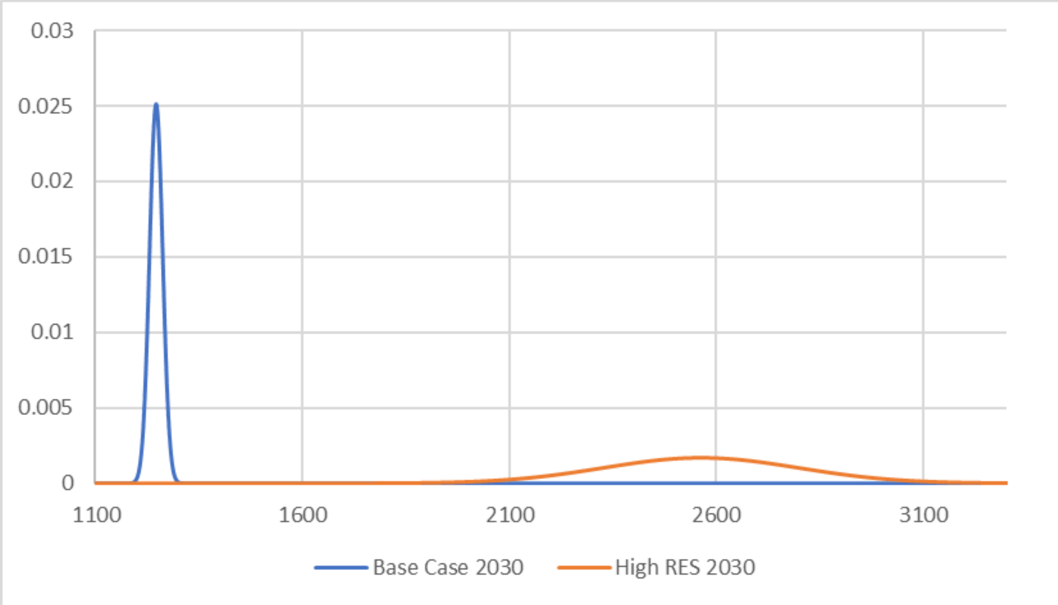
Since the results of flexibility needs are based on the 1000 Monte Carlo years it is not enough just to analyze the average (mean) values of flexibility needs not taking into the account the distribution of the flexibility needs, i.e., standard deviation. To fill this gap, in the following two figures we provide the Gauss distributions of daily flexibility needs for 2025 and 2030[5].

Figure 5.15 Gauss distribution of daily flexibility needs in 2025 for Base Case and High RES scenarios



[5] It should be noted that the axis scaling (for both *x* and *y*) is different on the figures

Figure 5.16 Gauss distribution of daily flexibility needs in 2030 for Base Case and High RES scenarios



It can be seen that with the RES increase expected values for flexibility needs is less probable since the standard deviation is greater. Namely, with the RES increase, the Gauss curve become more flattened (for the given average value), i.e., it is much more probable that flexibility needs will be different from the average value, i.e., from the expected value of flexibility needs.

We draw a similar conclusion for the weekly, as well as annual flexibility needs.

On the basis of these flexibility analyses, and the input data and Monte Carlo simulations for this study, we conclude that the Macedonian power system can cope with the foreseen level of RES integration with a high level of probability, as we find no Energy Not Served (ENS) in any of the analyzed scenarios. This implies that no additional means of flexibility are needed for the given boundary conditions at this time. The limited import scenario (V9), while low in probability now, would clearly pose a different situation, should future conditions indicate that the likelihood of that scenario is rising.

6 CONCLUSIONS

In this study, we analyzed the Macedonian power system based on the European Resource Adequacy Assessment methodology from 2021 to determine whether there will, in alternative time horizons (2025 and 2030 in this case) and conditions, be adequacy problems.

Using Antares, we created a tailored model for this study that **included almost all of Europe**, with different levels of detail. We modeled Southeast Europe, given its higher impact on the Macedonian power system, in great detail, taking into account all generation units and river cascades for each country. We modeled the rest of Europe with equivalent generation units. **The modelling encompassed 37 climatic years**, with data from the ENTSO-E PEMMDB and PECD, which allowed the model to cover a wide range of climatic conditions and situations.

In addition, **we performed a complex stochastic analysis for 1000 Monte Carlo years** to cover a high number of possible futures, to achieve convergence in our results, and to maintain a reasonable running time.

To cover many potential pathways for the Macedonian power system, **we worked closely with MEPSO to specify and evaluate 21 variations**, with 10 for each target year and an additional one for 2025. These included changes in demand, RES levels, and the Macedonian generation fleet, and regional changes in CO_2 emission prices, the level of decarbonization, and RES development.

The main indicators that the ERAA prescribes as relevant to determine whether there are adequacy issues are EENS and LOLE. **Out of the 21 scenarios, 19 scenarios showed no expected unsupplied energy in the Macedonian system (i.e., EENS and LOLE were zero)**. **This conclusion agrees with the ENTSO-E study for all of Europe, which found no adequacy issues in North Macedonia for 2025 and 2030.**

While reassuring, the question remains whether there could be an adequacy issue if some share of potential imports from neighboring countries were not available to the Macedonian system, given that North Macedonia is a significant importer. While **imports are an acceptable means to ensure adequacy in the ERAA**, we tested that dependency in the last two scenarios.

To do so, we constrained the model to not allow more than 70% of imports in the Base Case scenario, and this limitation showed some adequacy problems, with 911 GWh hours of unsupplied energy, which is around 20% of imported energy that in this case.

For this sensitivity, we checked the convergence of results, which is also an ERAA obligation, and found them to be satisfactory, and thus the results were reliable.

We determined that the best candidate for filling the adequacy gap in the Macedonian power system by 2025 in this case would be an additional gas TPP. For that candidate, along with other TPPs, we performed EVA to determine whether some existing TPPs might be candidates for decommissioning and whether new plants would be economically viable. **In that analysis, the existing large TPP**

TE-TO proved to be economically viable, along with a new gas TPP, as well as a TPP that could be built to fill the gap.

The EVA is a complex process that we recommend be further developed and researched to fully comply with Macedonian circumstances, and bring additional analytic resources to conduct the fully iterative process necessary to choose the best path forward.

We analyzed the flexibility of the Macedonian power system by adopting the Energy Community methodology to calculate different types of flexibility – daily, weekly and annual. We did so for the four most relevant scenarios (Base Case 2025 and 2030 and High RES 2025 and 2030 scenarios).

This flexibility assessment shows that flexibility needs increase with the rise in RES integration by around 30% in the Base Case scenarios, and around 80% in the High RES scenarios. We expect that with more RES, due to its variability and ramping needs, such flexibility needs will increase, and consequently, the need for suitable flexibility measures. Power system flexibility is a complex topic and revolves around metrics with no prescribed and generally accepted methodology to date. Hence, we recommend that MEPSO analyze system flexibility from under alternative day-to-day and longer term conditions in the future.

To conclude, we completed this pathbreaking ERAA with MEPSO, the first-of-a-kind in this part of Europe, one year prior to Energy Community obligations. It can serve as a sound basis for future adequacy assessments for all TSOs under ENTSO-E, with upgrades in the next iterations. With this study, MEPSO takes its place as a pioneer in the region in embracing the ERAA methodology.

7 APPENDIX

7.1 Definition of Monte Carlo years

As described in the previous chapter, each Monte Carlo year is a combination of climate conditions for wind and solar generation, load, and random samples of thermal power plant availability. Such an approach is fully compliant with the ERAA methodology. The user simulates each climatic year a number of times with the combination of random draws of power plant availability, and the model then calculates the LOLE and EENS based on the full set of simulated future states.

Figure below demonstrates the process of creating Monte Carlo years for this project. For the first 700 Monte Carlo years, we kept the correlation among Load, Wind (WPP), Solar (SPP) and Hydro (HPP) power plants constant, while changing the availability of thermal power plants (TPP). For instance, for the first 20 Monte Carlo years, we always used the same time series of Load, WPPs, SPPs and HPPs, while changing the (un)availability of TPPs. This approach takes all possible combinations of TPPs (un)availability into account for the climatic conditions reflected by the first Climatic Year. We used the same approach for the first 700 Monte Carlo Years, because there were 35 climatic years (conditions) and 20 different time series of TPPs (un)availability (35 x 20 = 700). We randomly built the remaining 300 Monte Carlo years, in which we did not maintain consistency among the Load, WPPs, SPPs and HPPs. These additional Monte Carlo years capture unexpected states of the power system, in line with ERAA best practice.

Figure 7.1 Monte Carlo years creation

CY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Load	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WPP	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SPP	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
HPP	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TPP	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

CY	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Load	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
WPP	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
SPP	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
HPP	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
TPP	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

CY	41	42	43	44				698	699	700	701	702	703	704	705	706	707	708	709	710
Load	3	3	3	3	…	…	…	20	20	20	rand	rand	rand	rand	rand	rand	rand	rand	rand	rand
WPP	3	3	3	3	…	…	…	20	20	20	rand	rand	rand	rand	rand	rand	rand	rand	rand	rand
SPP	3	3	3	3	…	…	…	20	20	20	rand	rand	rand	rand	rand	rand	rand	rand	rand	rand
HPP	3	3	3	3	…	…	…	20	20	20	rand	rand	rand	rand	rand	rand	rand	rand	rand	rand
TPP	1	2	3	4	…	…	…	18	19	20	rand	rand	rand	rand	rand	rand	rand	rand	rand	rand

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