Bulgarian Resource Adequacy Assessment

2022 Edition

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1. INTRODUCTION

This adequacy study is performed pursuant to Article 24 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity[1]. It has a regional scope and it is based on the methodology referred to in Article 23(3) in particular in points (b) to (m) of Article 23(5) of the mentioned Regulation.

Bulgarian resource adequacy assessments (BGRAA) contain the reference central scenarios as referred to in point (b) of Article 23(5) that cover projected demand and supply including the phase-out and mothballing of lignite power plants, and commissioning of new innovative low- and zero-carbon technologies for generation, consumption and energy storage. The central reference scenario contains targets for energy efficiency and electricity interconnection, as well as suitable sensitivity to developments in the price of carbon and wholesale pricing and extreme weather occurrences.

Separate scenarios in the BGRAA reflect the various probabilities of resource sufficiency issues, such as diversifying the gas supply and quickly replacing high-emissions supply with RES penetration. It falls short of the scope specified in the legislative package for "Clean Energy for All Europeans." Because a lot of specific information is needed to forecast and optimize a power system's functioning, the BGRAA 2022 scenarios and outcomes should not be interpreted or used under this new legal framework. Even with the greatest data available, the results are subject to significant ambiguity, which makes it challenging for market participants to make decisions.

Figure 1 illustrates the main elements of the BGRAA 2022 methodology and their impact on adequacy. The adequacy assessment considers, among others, generation, demand, demand-side response, storage and network infrastructure.

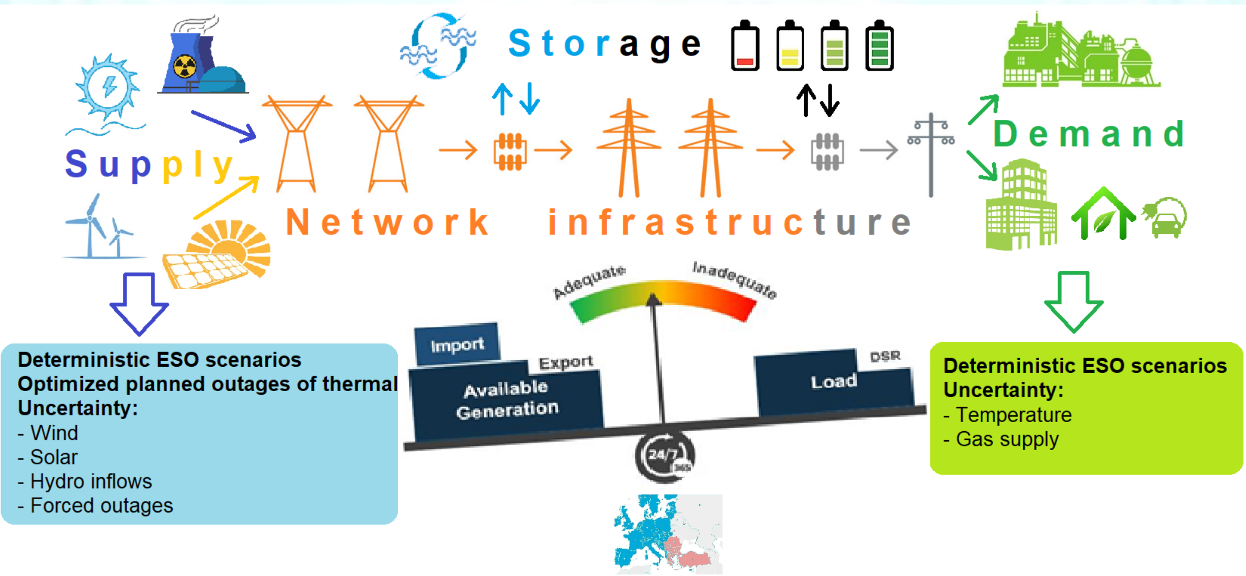

Figure 1: Overview of the BGRAA 2022 methodological approach.

[1] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN

2. MAIN FRAMEWORK

2.1. Geographical scope

The current investigation focuses on the surrounding biding zones that are connected to the Bulgarian power system. Zones are explicitly modelled, represented by market nodes that take into account all available information while using the highest input data resolution (e.g. information regarding generating units and demand). Only anticipated hourly trades between these market nodes and their environing explicitly modelled nodes are taken into consideration.

As shown in Figure 2, the goal of a BGRAA is to evaluate the supply's ability to fulfill demand over the mid to long-term while taking into account interconnections between the Bulgarian power system and its neighbors.

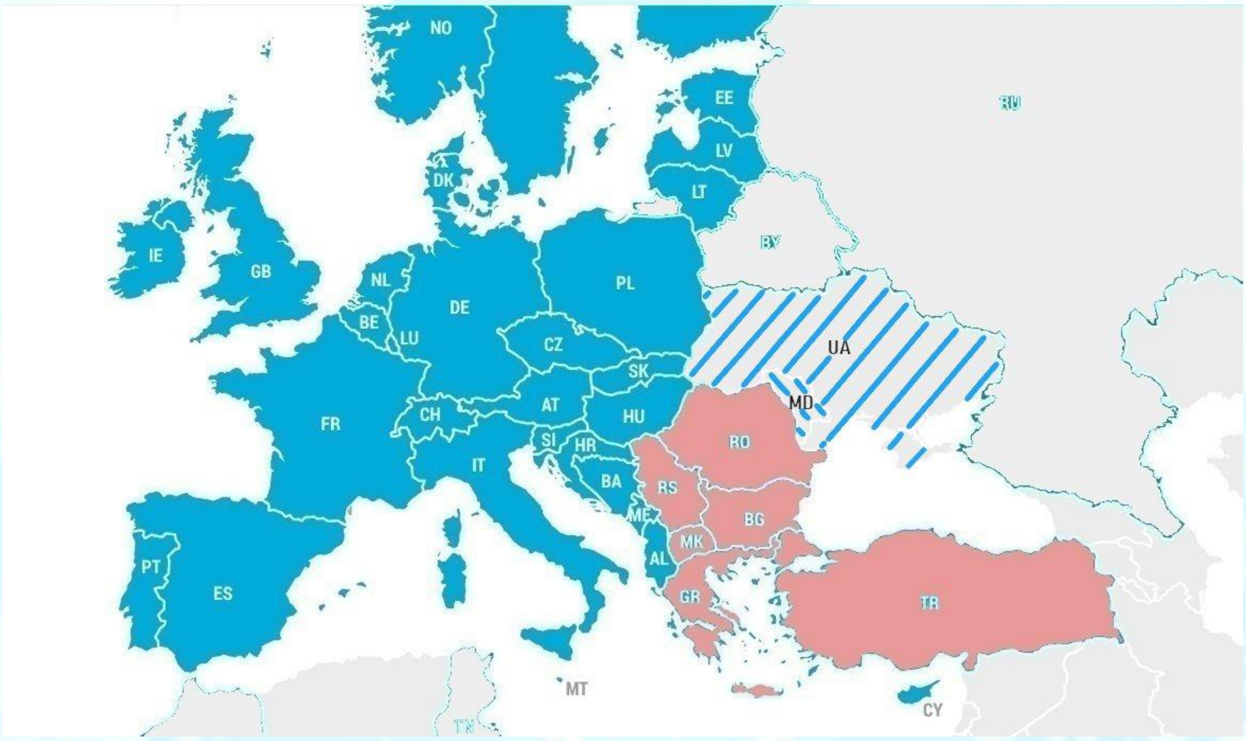

Figure 2: The interconnected Bulgarian power system modelled in the BGRAA 2022 (red color).

In total, 6 bidding zones in 6 countries are modelled explicitly in BGRAA 2022. The BGRAA only models interconnections between market/bidding zones and makes an abstraction of intrazonal grid topologies. Explicitly modelled member countries/regions and bidding zones include: Bulgaria (BG00); Greece (GR00); North Macedonia (MK00); Romania (RO00); Serbia (RS00) and Turkey (TR00). Non-modelled countries are the rest ENTSO-E bidding zones.

2.2. Target years and resolution

The BGRAA aims to identify adequacy risks up to 10-year ahead and thus assists stakeholders in making well-informed investment decisions. The BGRAA 2022, as the first edition of a stepwise implementation, focuses on target years (TYs) 2023, 2027 and 2032, and considers techno-economic trends and policy decisions relevant for the assessed TYs (e.g. the phase-out of certain generation technologies).

An hourly simulation resolution, also referred to as an hourly market time unit, has been adopted for all TYs and scenarios. All input time series data for the unit commitment and economic dispatch (UCED) model (e.g. RES generation, demand profiles and net transfer capacities - NTCs) are consequently expressed in hourly intervals. Data provided in a seasonal format are transformed into hourly time series before being fed into the UCED model.

2.3. Modelling assumptions

The BGRAA model is a simplified representation of the neighboring biding zones connected to the Bulgarian power system that – like any model – is based on a set of assumptions, which includes:

1) **Centralized generation dispatch planning:** Based on the generation units' marginal production costs and other plant factors, the modeling tool deploys them for the chosen time horizon.
2) **UCED processing is based on perfect information:** It is assumed that all variables, including the amount of RES energy available, thermal capacity, demand-side response (DSR) capacity, grid capacity, and demand, are perfectly known in advance and that there are no discrepancies between projected and actual usage. Furthermore, all factors determining the best hydro dispatch are considered to have perfect foresight.
3) **Demand is aggregated by bidding zone[2]:** Individual end users or groups are not modelled.
4) **Demand elasticity regarding climate and price:** Demand levels and weather are somewhat connected. For instance, changes in the use of electrical heating/cooling systems will impact demand levels as a result of temperature differences. Demand is thought to be inelastic to price, meaning it will remain stable regardless of the price of energy. The latter also includes new consumers, such as heat pumps and electric vehicles (EVs), which are modelled based on a consumption pattern that is inelastic to price.
5) **Energy markets modelling only:** The BGRAA only models resources that are readily available to the market. The reference scenarios do not model non-market resources like strategic reserves. From a day-ahead/intraday market standpoint, sufficiency is assessed. Since inadequacy is the BGRAA's main concern, it should be assumed that the system is not structurally balanced, at least during some hours and/or days. Furthermore, forward/futures markets and contracts between market participants are not modeled. Thus, they have no impact on resource capacities that have been modelled.
6) **RES production depends on climate:** Solar, wind and hydro power generation directly depend on climate conditions.
7) **Forced outages (FOs) only affect thermal generation:** In a certain TY, a power plant's net generating capacity is not always assured. Planned grid outages are included in the NTCs provided by TSOs, whereas FOs are randomly created for thermal assets within the modeling tool. Finally, FOs have no effect whatsoever on planned maintenance.
8) **Upcoming FOs considered in UCED:** With a one-day look-ahead horizon, FOs are generated at random but are known at the time of the UCED. As a result, the units are deployed appropriately to prevent or reduce load loss.

[2] https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/Demand%20Dataset.7z

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9) **Optimization of planned maintenances of thermal units:** Unlike planned thermal unit maintenance, which is scheduled during the least crucial times since it has perfect foresight of the demand pattern, FOs happen at random across time (i.e. periods with likely supply surplus rather than supply deficit). The maintenance optimization is based on typical climate conditions and takes into account country-specific limits like the maximum number of units that can be maintained simultaneously.

10) **NTC approach:** The relative NTC between the market nodes serves as a limiter for electricity exchanges between market nodes, which are optimized as part of the UCED model optimization. The NTC approach solely takes into account bilateral power flows and ignores the effects of flows in neighboring regions.

11) **Electrolysers are not modelled:** Electrolysers are not explicitly simulated because it is thought that they have little effect on adequate parameters. Due to high market pricing, electrolysers are thought to not use any electricity during times of scarcity.

3. PROBABILISTIC ASSESSMENT

According to the European Resource Adequacy Assessment (ERAA) 2021 Executive Report[3], the majority of member states use probabilistic adequacy indices to track the reliability of their power systems, most frequently the loss of load expectation (LOLE). Therefore, a contemporary adequacy assessment must take into consideration the system's uncertain variables and provide a probabilistic indication of the situation's adequacy under a variety of likely realizations of the variables' uncertainty. The so-called Monte Carlo (MC) simulation approach is the most recent way for calculating LOLE and expected energy not served (EENS) in adequacy investigations. A huge number of scenarios, each with a random realization of unforeseen outages, make up the applied MC simulation. Assets used for generating and transmission experience these disruptions. For each scenario of the predicted environment, the random outages of assets are chosen in the ERAA 2021. A broad range of potential system states can be studied as a result of the combination of random outages and climate conditions. Then, results can be evaluated based on probability, meeting the needs of volatile modern power systems. The assessed indicators, used MC simulation, and convergence criteria are all presented in this section.

3.1. Monte Carlo Adequacy Assessment

MC simulations are based on Antares-Simulator[4] which is at the core of the BGRAA. In order to reflect consistent historical climatic years, a number of distinct climate scenarios are established. Then, a number of random forced outage realizations are coupled with each climate year. The forced outage distributions for generating and interconnection assets are used to generate each forced outage realization. An MC year is a sequence of model runs that is carried out for a single climate year and all associated random forced outage realization.

As a first step, climate years[5] from 1982 – 2016 are selected one-by-one (N climate years). Each climate year represents a consistent set of time series:

- Temperature-dependent demand;
- Wind and solar load factors;

[3] ERAA 2021 Executive Report
[4] https://antares-simulator.org/
[5] https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/ERAA/Climate%20Data.7z

- Hydro generation, inflows, minimum/maximum generation or pumping capacity, and minimum/maximum reservoir level (where applicable);
- Climate-dependent for other RES and other non-RES generation.

Keep in mind that the data for the climate year listed above may vary depending on the target year chosen.

For each climate year, numerous sets of randomly generated FO realizations (hourly time series) are created as a second phase (M=20 forced outage samples per climate year). FOs for thermal generation units are included in the sets of FO realizations. The schedules for the planned maintenance are unaffected by FO realizations. In Section 2.3, the convergence is covered in more detail. The combination of N (35) climate years and M (20) forced outage realizations per climate year results in a total of N x M model runs (700 for BGRAA). Each model run is optimized individually. Figure 3 illustrates the described MC approach for each TY studied.

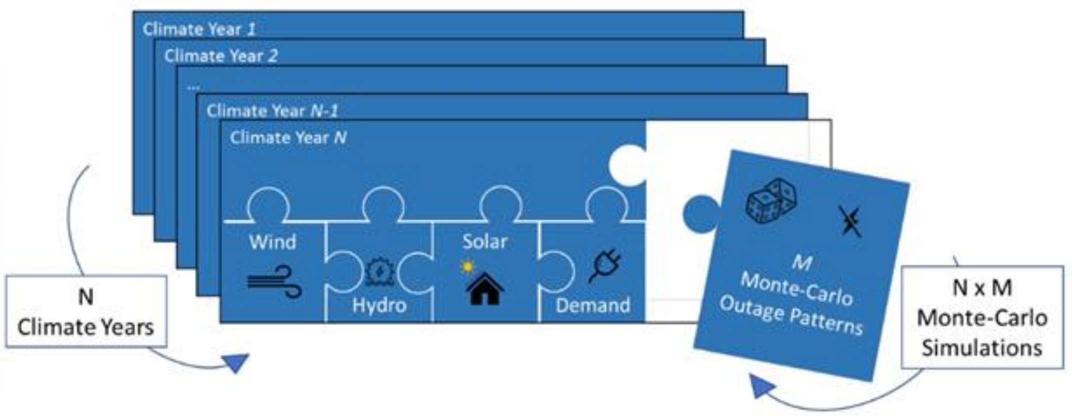

Figure 3: Monte Carlo simulation principles for a given target year (source: ERAA 2021).

3.2. Adequacy Indicators

According to Article 23 (5) of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity, the following indicators and their derivative are used to assess the adequacy levels for a given geographical scope and for a given time horizon:

- **Loss of load duration (LLD) [h] –** the duration in which resources (such as production capacity, imports, and demand flexibility) are not enough to meet demand. It does not convey how severe the deficit is (ENS). Consider that the LLD indicator's granularity is also transferred to the model's hourly time resolution.
- **LOLE [h] –** the anticipated number of hours across several scenario runs, such as climatic years and/or FO realizations, during which resources won't be enough to meet demand. According to Eq. (1), LOLE can be determined as the mathematical average of the relevant LLD over the taken model runs: For J the total number of considered model runs and LLD_j the LLD of model run j, then

$$LOLE = \frac{1}{j}\sum_{j=1}^{j} LLD_j \quad (1)$$

- **ENS [GWh]** – the total amount of electricity demand that, due to a lack of resources, cannot be met. The total ENS of all the nodes in a geographical scope is referred to as the ENS for that scope. An empty ENS indicates that there are no adequacy issues.

- **EENS [GWh]** – the electricity demand which is expected not to be supplied due to insufficient resources. The total EENS of all the nodes in a geographical scope is referred to as the EENS. According to Eq. (2), EENS can be calculated as the mathematical average of the corresponding ENS over the taken model runs: For J the total number of considered model runs, and ENS_j the Energy Not Served of model run j, then

$$EENS = \frac{1}{j}\sum_{j=1}^{j} ENS_j \qquad (2)$$

4. MAIN INPUTS AND UNCERTAINTIES

4.1. Supply/Resource side

In the BGRAA 2022, generation units are classified as RES, Non-RES, storage and DSR. Table 1 shows the categorization and spatial granularity of considered generation technologies.

Table 1: Classification of supply units

Category	Technology	Granularity
RES	Wind	aggregated in PECD zones; onshore and offshore wind capacities are collected and modelled separately
	Solar	aggregated in PECD zones; solar PV and solar thermal with and without storage are collected and modelled separately
	Hydro RoR and Pondage	aggregated in market nodes
	Hydro with traditional reservoir	aggregated in market nodes
	Other RES	aggregated in market nodes
Non-RES	Coal/Lignite	unit-by-unit
	Gas	unit-by-unit
	Nuclear	unit-by-unit
	Other Non-RES	aggregated in technology bands
Storage	Batteries	aggregated in market nodes
	Open-Loop PSP	aggregated in market nodes
	Closed-Loop PSP	aggregated in market nodes
DSR	DSR	aggregated in technology bands

Generation data are provided by concerning TSOs through the Pan-European Market Modelling Data Base[6] (PEMMDB). The Pan-European Climate Database (PECD) includes climate-dependent data such as hydro inflows, solar and wind production time-series. In the absence of any necessary input parameter, Common Data gathered by ENTSO-E is used as a default.

4.1.1. Non-RES

Major thermal units are modelled unit-by-unit, as can be seen in Table 1 above. For the adequacy simulation, only units that are currently on the market are taken into account. Thermal units are dispatched in accordance with other plant factors, such as associated expenses for CO_2 emissions, and their marginal output costs. All TYs will have carbon costs of €90 per ton. For biofuel units, the price of CO_2 emissions is set at 0 Euro/MWh. Central heating power plants (CHP) and industrial co-generation are modelled based on their yearly profiles on hourly granularity.

[6] https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/PEMMDB%20National%20Estimates.xlsx

According to the BGRAA 2022, Table 2 outlines the consideration of unit-specific technical factors as modelled, non-modelled, or simplified modeling. Technical factors that are thought to significantly affect resource adequacy are explicitly modelled or made simpler. The simulation ignores variables that are irrelevant or have no bearing on the availability of resources. For all TYs, the gas cost is set at €120 per MWh/d.

Due to the simulations' assumption of perfect foresight, the effects of ramp rates and minimum up/down times on adequacy indices are minimal. Situations of scarcity are foreseen beforehand, and units are ramped up early enough to handle any risk of inadequacy and the ensuing high cost. Start-up Times are modeled in an oversimplified way, only after a unit has a forced outage. In certain circumstances, Start-up Time restrictions may affect sufficiency since the outage prevents the unit from beginning earlier.

Table 2: List of modelled and non-modelled technical parameters of thermal units

Parameter	Description	Consideration
Forced Outage Rate	Likelihood of an unplanned outage	Modelled
Must-run [MW]	Hourly constraint for single or group of units to produce at least a certain amount of MW	Modelled
Min Stable Level [MW]	Minimal operation level of a unit.	Modelled
Derating [MW]	Hourly constraint for single or group of units to reduce the capacity offered to the market	Modelled
Start-up Time [h]	Time interval required to start a unit from 0 to Min Stable Level	Modelled
Ramp Rates [MW/h]	Limitation on the increase/decrease of the generation level within one hour for a unit that is already dispatched.	Modelled
Min Up / Down Time [h]	Minimum time interval that a unit should be in/out of operation by technical reasons	Modelled
Balancing Reserve Procurement	Balancing reserves that are procured to serve for operational stability purposes	Modelled

The technology Other Non-RES includes numerous bands of aggregated Non-RES technologies for each market node in addition to unit-by-unit thermal generators. In time series of aggregated capacity with an hourly derating profile, similar smaller plants are grouped together by technology and given a must-run status. Co-generation units, waste incineration facilities, non-dispatchable thermal generation, and any other facilities that cannot be delivered on a unit-by-unit basis are typically included under Other Non-RES.

4.1.2. RES (no hydro)

The total installed capacity for wind, solar, and other RES technologies is specified at the PECD zone level and equals the total of all individual plant and aggregated capacity. Additionally, TSOs' individual units and/or aggregated capacity can be given hourly generation curves. Climate affects solar and wind generation, which is caused by, respectively, solar irradiation and wind conditions. The hourly time series already includes scheduled and unforeseen outages for RES and Other RES, thus they are not explicitly modelled. The optimization model decides whether to inject free energy from RES and other RES into the grid or to reduce their availability.

4.1.3. Hydro

Hydro capacities are combined by technology type and bidding zone. The pan-European Hydropower Modelling Database that supplements the PECD[7] (also known as the "PECD Hydro

[7] Hydropower modelling - New database complementing PECD

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database") contains information on the availability of hydro energy inputs, extra hydro limitations, and the criteria for capacity aggregation. In total, hydropower plants fall into four different technological subcategories:

1. Run-of-river (RoR) and pondage;
2. Reservoir;
3. Open-loop pumped storage power plant (PSP) reservoir;
4. Closed-loop PSP reservoir.

The RoR and pondage category includes RoR generators that include pondage, swell RoR, and modest daily storages, i.e., without pumping capabilities and with a ratio of reservoir size [MWh] to net generation capacity [MW] less than 24 hours. Major hydro storage facilities that lack pumping capabilities are grouped with conventional reservoirs. PSPs are classified as either open-loop PSP reservoirs, which have natural inflows, or closed-loop PSP reservoirs, which have no inflows at all.

Hydro inflows, minimum and maximum generation, and reservoir level restrictions all place limits on the maximum and minimum power that can be used for turbining. The (weekly) maximum generation limits include forced outages or maintenance of hydro technologies. Depending on the input data supplied in PEMMDB for the unusual generation mix of the market nodes within their control zones, data availability varies.

Hydro Inflows – Given the hourly resolution of the simulation, the available cumulative daily or weekly energy lots are equally distributed over 24 or 168 hours, respectively. Depending on the hydropower category, inflows are either promptly dispatched (such as in the case of pure RoR generation) or retained in the hydro reservoirs and released in accordance with the modeling tool's optimum reservoir management. The modelling tools may opt to release the excess input if the available hourly inflows are more than the trajectories for the maximum reservoir level or the dispatch needs.

Minimum and Maximum Generation (output power or energy) constraints regulate the hourly hydropower dispatch. Maximum generation is set to equal total installed capacity and minimum power is presumed to be zero if not explicitly specified. Since RoR generating is by definition not dispatchable, the daily intakes are turbined at a fixed hourly output throughout the day. The dispatch flexibility is given in accordance with the minimum and maximum generation profiles, which represent the dispatchable swell or pondage share of the aggregated capacity and the non-dispatchable RoR, respectively, if a non-zero reservoir size is specified for the RoR and pondage category. The minimum and maximum generated energy constraints are weekly restrictions on the energy output that are implemented in an intertemporal way, i.e., the total generation over the course of the entire week has to be lower (or higher) than the relevant week's maximum (or lowest) energy constraint.

Reservoir Level Restrictions are handled as discrete hard constraints that must be applied by the modeling tool on the first hour of the week. However, due to the inherent complexity of maximizing hydropower generation from hydro reservoirs with seasonal and/or climate-dependent restrictions and inflow patterns, there is occasionally a risk of punctual impossibility. These impossibilities typically result from the solver's rigid enforcement of the starting reservoir level (or minimum/maximum level) at the start of the week. When these problems are found, the typical answer is to give the solver the ability to treat the reservoir level trajectories as soft restrictions that can be broken only with a significant penalty. The solution will prioritize the dispatch of hydro resources and inflows during hours of generating shortage to prevent ENS if potentially in conflict with hard reservoir restrictions by setting the penalty cost sufficiently high but still below the value of lost load.

Minimum and Maximum Pumping are treated analogously to a minimum and maximum power output constraints.

4.1.4. Battery storage

Battery storages are being used more frequently as a way to give the grid flexibility. This adaptability can be applied either behind the meter or in the market. Market-participating batteries are explicitly modeled, and the probabilistic modeling optimizes their dispatch. The following are the primary criteria taken into account for this technology type:

- Installed output capacity (MW);
- Storage capacity (MWh);
- Efficiency (default: 90% per cycle).

Batteries that are not market participants are not explicitly modelled but are exogenously incorporated in the demand profiles based on data from PEMMDB.

4.1.5. DSR

While the bulk of demand acts as a constant input and is expected to be inelastic to power prices generated by the model, a portion of demand is explicitly treated as price-elastic DSR.

The DSR capacity varies by market node and by time of day. The TSOs in PEMMDB have submitted a dataset that consists of:

- the maximum DSR capacity [MW];
- the actual availability [MW] for all hours of the year;
- the maximum number of hours the DSR source can be used per day (default: 24 hours).

DSR is equivalent to all other generating assets from a modeling standpoint, but it has an activation price that is greater than the marginal cost of the majority of other generation categories and an availability rating that restricts its actual capacity in any given hour.

4.1.6. Balancing Reserves

Ancillary services, also known as balancing reserves, are power reserves that TSOs hire to stabilize or restore the grid's frequency after minor or significant interruptions caused by things like unexpected plant failures, changes in load, and RES. Only manual frequency restoration reserve (mFRR) and replacement reserves (RR) are taken into account as being available for adequacy reasons in the BGRAA, despite the fact that they are essential to a power system's stability. BGRAA does not examine events that take place within each hour; instead, it analyzes structural deficiencies that become apparent in time steps of one hour or greater. Operational reserves (FCR and aFRR) are set aside for operational purposes in order to prevent scheduling them for time increments of an hour or more, which would prevent them from serving their intended purpose.

In terms of modeling, reserves can be taken into account in two different ways: by lowering the corresponding thermal generation capacity or by raising demand by include the hourly reserve capacity requirements. In order to make the market models easier to implement, the reserves were taken into account by adding them as a flat demand rather than by reducing the generation capacity. However, as "virtual consumption" has been introduced, doing so has the drawback of altering the stated energy balance. Hydropower generating provides reserves in several bidding zones. They are used in these situations to limit the maximal hydro production. When necessary, demand reduction agreements or specialized backup power plants are in place between a TSO and significant electrical consumers, for example, reserve specifications are directly coordinated with the TSO data correspondent under those unique circumstances. However, mFRRs and RRs are taken into account while determining the BGRAA's adequacy.

4.2. Grid side

The BGRAA 2022 did not centrally optimize planned maintenance for transmission lines; instead, it was regarded as integrated into the NTC hourly availability, as reported by TSOs. The same deterministic planned outages and random FOs that are modeled for generation resources also affect transmission levels. In the event that TSOs do not offer specified FOR values, default assumptions of 0% for HVAC are used.

Due to FB modeling automation being lacking, the FB approach is now only used in the BGRAA 2022 during the hours with adequacy problems. Simple NTC modeling is in effect for the remaining hours.

4.3. Demand side

Hourly demand profiles are based on TRAPUNTA[8], an external ENTSO-E tool that enables the reconstruction of whole daily load profiles, overcoming the shortcomings of conventional techniques. Through mathematical analysis of the supplied integral load profiles, key load components are intended to be isolated. By using a mathematical strategy, TRAPUNTA is able to extract a set of a few orthogonal basis functions that may be applied to rebuild various load profiles for a single node, including:

- Identification of dependencies linked to various groups of days;
- Prediction of the entire daily load profile;
- Analysis of the changes in the entire daily load profile over the course of the year;
- Recognition and display of bank holidays in particular market nodes;
- Recognizing seasonal patterns, such as those related to daylight saving time and the summer vacation period.

The final load time series for Bulgarian biding zone are linearly up-scaled based on yearly demand forecast in Bulgarian NECP[9] and ERAA 2021 input load time series.

5. OPTIMIZATION AND ECONOMIC DISPATCH

5.1. Maintenance profiles

Maintenance profiles are only generated for thermal units with a unit-by-unit resolution. The maintenance of renewables, other non-renewables and storages are considered to be included in the collected infeed time series of these generators.

The ANTARES tool generates maintenance profiles of thermal power plants (clusters in ANTARES) on the basis of user-defined 365-day arrays of:

- planned outage rates (POR, lies in [0, 1]);
- planned outage duration (POD, lies in [0, 1]);
- minimum number of units in a planned outage (PO Min Nb - integer lies in [0, PO Max Nb]);
- maximum number of units in a planned outage (PO Max Nb – integer lies in [PO Min Nb, Number of available units in the cluster].

[8] Demand Forecasting Methodology
[9] https://energy.ec.europa.eu/system/files/2020-06/bg_final_necp_main_en_0.pdf

The resulting distribution of maintenance is consequently translated back to the maintenance schedules of individual units. The maintenance is consequently optimized for each bidding zone separately.

5.2. Forced outages

For each generation unit or interconnector, forced outage rates (FOR) are represented as a single percentage. Within each modeling tool, FO are generated at random for each stochastic component of the simulation. Unit-by-unit generators and connecting lines are stochastic components in the BGRAA 2022 that need to be taken into account. TSOs offer the following details to define the outage behavior:

- FOR – i.e. the likelihood of a forced outage;
- Mean Time To Repair – i.e. the duration of a forced outage.

FORs are taken into account for each individual thermal unit and depend on the technology and unique features of the plant. The best historical estimate for the technology is utilized as the default value if the TSO does not supply a FOR for a specific thermal unit. Interconnections use the same technique.

5.3. Storage optimization

After creating the FO pattern and prior to the UCED optimization, the modeling tool performs an additional optimization phase for storage assets. A weekly time resolution is used to optimize the stored energy that is available. When there is a sufficient supply of energy, it is stored and made accessible for use when there is a high demand and insufficient supply of energy at the same time. The optimization is simultaneously constrained by exogenously provided weekly hydro energy targets.

5.3.1. Hydro storage

The most challenging aspect of storage optimization is hydro storage. They are limited by daily reservoir level restrictions in addition to hourly available generation and storage capacity. The minimum and maximum daily reservoir levels represented by these limits are historical or technical, according to TSOs. To pre-define the reservoir level at the start of each week, TSOs can also offer deterministic weekly trajectories per climate year. If both are available, minimum and maximum reservoir trajectories are chosen over deterministic climate-dependent weekly trajectories because they give the system more flexibility. 0% and 100% of the total reservoir size serve as continuous maximum and minimum hard restrictions over the whole simulated time period when both are absent. As stated by TSOs, the initial reservoir level is used as the fixed trajectory value during week 1. The average between the minimum and maximum level trajectory at week 1 is used if it is not available. If any or both of the data are missing, 50% of the reservoir's capacity is taken as the default value. TSOs can offer fixed trajectory values for the ultimate reservoir level in a manner similar to this. Standard values are used as the mean between the minimum and maximum reservoir restrictions, or 50%, if the value is unavailable or inconsistent. It is assumed that the pumping-turbining cycle efficiency is equivalent to 70%.

Prior to the hourly UCED optimization, the modeling tool performs a pre-optimization phase for hydro storages at a coarser time granularity. In this pre-optimization, the energy profile of hydro storage assets that are currently available is optimized in daily energy lots so that hydro resources are saved and stored in the reservoirs over the course of the year and made available to each daily UCED sub-problem related to the corresponding electricity requirements of each bidding zone. Reservoir pre-optimization distributes the energy from hydro storage assets that are available over the course of the year in the best possible way, minimizing system costs (also known as generating costs).

5.3.2. Batteries

TSOs give battery data that is divided into in-market and out-of-market batteries. The BGRAA 2022 process only models commercial batteries. Consequently, the BGRAA does not take into account behind-the-meter battery storage (integrated with PV systems).

Two characteristics of batteries are their output capacity (measured in MW) and their storage capacity (measured in MWh). It is assumed that the battery is first charged to 50% of its storage capacity at the beginning of the experiment. Additionally, a 90% charging efficiency assumption was used, and a 100% discharge efficiency assumption was made. Energy delivered from the battery to the market is valued at zero cost, however energy used by the batteries (demand) is valued at market price. Overall optimization aims to discharge batteries at high electricity prices and charge them at low electricity rates in order to reduce total system expenses.

5.3.3. P2X

Only power-to-gas devices are covered by P2X data in the current PEMMDB version. Electrolyzers are not included in the adequacy simulation in the BGRAA 2022 since it is believed that they won't use power during times of scarcity or when costs are high, having little of an effect on the adequacy indicators.

5.4. Economic Dispatch

The UCED optimization is a two-step process with a system cost reduction goal; in other words, it seeks to reduce the total cost[10] of producing energy while keeping in mind that power consumption must be met. To account for inter-temporal restrictions that may last across the entire year, an annual optimization for the target year is performed in the first step. Included in this is hydro optimization. To handle the big optimization problem in a fair amount of computation time, numerous hours are pooled and optimized in blocks in this pre-optimization. Pre-optimization anticipates and takes into account the best maintenance plan for thermal equipment

For objects having annual constraints, the results of this first optimization phase are more precise daily target values. This results in daily reservoir targets for hydro units, which are established as soft boundaries to the total hydro energy available throughout the course of the day for the next, more precise optimization stage.

The units that are dispatched at each hour of the TY and the appropriate dispatch level for each unit are then determined using the UCED optimization in smaller time steps (for example, one day). A certain TY is separated into various UCED optimization time steps/horizons for optimization. Based on the profiles of its available thermal net generation capacity, RES available energy, grid NTCs, and demand, each UCED problem that results is optimized. Each UCED problem is then given the previous UCED problem's final system state. In fact, optimizing a particular UCED problem with a different initial dispatching state while maintaining the same other parameters might provide various outcomes.

Utilizing reservoirs and PSPs as variable hydro storage resources, the UCED optimization problem solver takes advantage of marginal price gain opportunities from the perspective of overall welfare. The solver takes into account the reservoir level trajectories and exogenously supplied generation limitations. The current hydropower modeling methodology does not explicitly account for water

[10] Methodology for calculating the value of lost load, the cost of new entry and the reliability standard

values or exogenous shadow prices for water. Final marginal prices are set equal to the greatest marginal cost (merit order) of the dispatched resources (e.g., RES, thermal, DSR, imports, etc.) to fulfill the hourly domestic demand as a direct result of the hourly optimization of hydro storages. As a result, the residual load is matched with the hydro resources and least-cost resource capacity, a process known as "Hydro-Thermal" optimization. It follows logically that pumping operations are scheduled for periods of low demand and/or resource surplus, whereas turbining happens during periods of high demand and/or low available generation (high marginal price).

5.5. Capacity mechanisms

Different support schemes are in place in the region. Some are applied in Non-EU countries, respective not in line with EU legislation, others are based on green deals in EU members. Due to this complexity, in BGRAA 2022 all scenarios are considered without capacity mechanisms in the concerned bidding zones.

6. LIMITATIONS

The present BGRAA uses a highly sophisticated probabilistic market modeling methodology. However, it has inherent limits, which are as follows, just as every modeling approach:

- **Thermal planned maintenance optimization:** For isolated market nodes, maintenance optimization of thermal generation assets is carried out individually. Additionally, it is only optimized using one reference climate year, disregarding the contribution from solar and wind energy.
- **NPP planned maintenance:** It is fixed in advance, depending on nuclear fuel cycles.
- **DSR limitations:** Shiftable load is not yet taken into account in the simulations, and DSR is simply modelled as a potential demand drop in the event of high pricing. Demand can be rescheduled from a time of high prices to one of reduced costs thanks to shiftable load. For the time being, the demand forecasting approach takes shiftable load, such as the desire for EVs, into account. Additionally, the current methodology takes into account that some of the demand is price-elastic, but no other factors.
- **Thermal and grid assets are not affected by climate conditions:** In reality, thermal and grid assets capacities may vary with air temperature and humidity, for example.
- **Internal grid limitations within a bidding zone are not considered.**
- **No FO sampling is done for RES:** No random outage draws are considered for RES.
- **FOs are assumed to not affect planned outages:** Planned outages of generation units are typically scheduled months or years in advance. They could still alter, though, based on the contractual and operational restrictions placed on each plant owner. In practice, the planned outage may be moved at a different time or even combined if a FO occurs relatively close to it.
- **Procurement of ancillary services:** As a simplified assumption, only balancing services for FCR and aFRR as part of ancillary services are modelled by adding a fixed demand. This has an impact on the simulated market prices. mFRRand RR are assumed to be used in scarcity situations, in order to cover the reference incident - the largest imbalance that may result from an instantaneous change of active power of a single power generating module, demand facility, or from tripping of an AC line within the LFC block.

- **Sectoral integration:** Sectoral integration technologies, such as those for converting electricity into gas and hydrogen as well as electricity converted into other media, are not taken into account.
- **Network:** The BGRAA 2022 is built on the NTC approach for the representation of grid elements. FB approach will be applied only in cases where LOLE>0 in the Bulgarian bidding zone.
- **Must-run units:** Must-run plants are typically small hydro, biogas, CHP plants or co-generations linked to an industrial consumer. They are presented with a fixed hourly profile.
- **Mothballing, refurbishment, and retrofitting of generation resources** are not considered.

7. SCENARIOS

The central reference scenario is based on the Bulgarian NECP and it is applied to all TYs (2023, 2027 and 2032). All neighbor bidding zones are modeled based on inputs of ERAA 2021[11].

The alternative scenario is based on the outcomes of the national recovery and resilience plan (NRRP) for Bulgaria[12], where projections for CO_2 emissions from lignite power plants reduction by 40%, higher RES penetration and huge storage deployment by the end of 2026, is envisaged. Two TYs are considered under the NRRP - 2027 and 2032 (no further development of conventional, renewable or storage assets is foreseen between 2027 and 2032, only phase out of additional coal units).

Another green ambition scenario is defined by modifying the NRRP for TY2032 scenario with decommissioning of all lignite-fired power plants in Bulgaria.

Due to the ongoing war in Ukraine and the possible scarcity of natural gas supply additional gas crisis scenario is modeled for 2023. Co-generation and gas-fired district heating plants in the Bulgarian bidding zone maintain alternative fuels, such as gas oil and naphtha, which can be used by the respective boilers for the heat supply needs and can provide up to 60% of the heat load during the winter season. In addition, even in the event of a complete curtailment of gas supply, some of the cogeneration plants can use alternative fuels for limited electricity generation. Furthermore, the Bulgarian gas transmission network is connected to those of neighboring countries, which allows the use of alternative gas supply routes, as well as partial diversification of supply, insofar as Bulgaria is not currently entirely dependent on a single supplier. In other words, under any scenario, it cannot be expected that the entire heat load will be provided by increased electricity consumption. Due to the significant range of partial gas supply interruption scenarios and the myriad of combinations for securing the heat load, including through increased electricity consumption, a gas crisis scenario with the following assumptions has been adopted for the purposes of the electricity system adequacy assessment:

- 100 MW band reduction in industrial users' electrical load during winter;
- Reduction of electricity generation from Co-generation by 40% (currently in the Industrial co-gen the reduction is 25%);
- 40% of district heating clients (domestic and tertiary sector) switch to electric heating;
- 100% of clients (domestic and tertiary sector) using direct gas for heating switch to electric heating.

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[11] ERAA 2021 - Input Data
[12] http://nextgeneration.bg/14

- for Serbia and North Macedonia, a commensurate additional load is assumed relative to Bulgaria's annual consumption and the same daily profile;
- for Romania, Greece, and Turkey no additional load is assumed due to the availability of local gas fields in Romania and the possibilities for diversification of gas sources for the other two countries.

A detailed description of the used methodology is provided in Annex I.

All investigated scenarios in BGRAA for respective TYs are presented at table 3.

Table 3: BGRAA scenarios and TYs

Scenarios / Target years	2023	2027	2032
National Energy and Climate Plan (NECP)	Y	Y	Y
National Recovery and Resilience Plan (NRRP)	N	Y	Y
Geen Ambition (lignite closure)	N	N	Y
Gas crisis	Y	N	N

8. RESULTS

The results represent only the Bulgarian bidding zone for different scenarios and TYs. More detailed results for the Bulgarian bidding zone are presented in Annex II for the following scenarios: Gas crisis 2023; NRRP 2027 and Green ambition 2032.

8.1. Adequacy results

No adequacy concerns in the Bulgarian bidding zone were detected in each set of 700 MC simulations for different scenarios and TYs.

Table 4: BGRAA adequacy results

Scenarios / Target years	2023		2027		2032	
	LOLE	ENS	LOLE	ENS	LOLE	ENS
National Energy and Climate Plan (NECP)	0	0	0	0	0	0
National Recovery and Resilience Plan (NRRP)			0	0	0	0
Green Ambition (lignite closure)					0	0
Gas crisis	0	0				

8.2. Economic and ecological outcomes

Economic and ecology results don’t include the costs of co-generation on gas, where yearly profiles are used instead of UCED.

The results represent in the next tables are the average values of each set of 700 MC simulations for different scenarios and TYs. The regional scope of BGRAA predetermines lower marginal prices and lower export from the Bulgarian bidding zone for 2023 than expected, compared to the present internal market situation. In fact, the huge fleet of gas-fired power plants that determines the price of market coupling is concentrated in central Europe. Therefore, for 2023 it can be expected that the lignite fleet in Bulgaria will still operate at maximum capacity as it is cheaper than the gas fleet in central Europe and the marginal prices will be higher than the presented ones.

Table 5: Average yearly marginal price – Bulgarian bidding zone

Scenarios / Target years	Marginal price yearly ave, [EUR/MWh]		
	2023	2027	2032
National Energy and Climate Plan (NECP)	135.11	144.87	163.19
National Recovery and Resilience Plan (NRRP)		169.55	113.49
Green Ambition (lignite closure)			115.96
Gas crisis	146.59		

Note: Co-gen on gas not incl.

Table 6: Yearly operational costs – Bulgarian bidding zone

Scenarios / Target years	Operational costs, [bln. EUR/year]		
	2023	2027	2032
National Energy and Climate Plan (NECP)	1,76	2,22	1,5
National Recovery and Resilience Plan (NRRP)		1,64	0,89
Green Ambition (lignite closure)			0,188
Gas crisis	1,9		

The results show that a gas crisis would not affect the adequacy of the Bulgarian bidding zone in the short term. It should be noted though that the Bulgarian power system operates synchronously with the rest of continental Europe, i.e. any disturbance outside is reflected in the real-time control. In addition, the market coupling in Europe implies that the generated electricity is distributed according to the supply and demand curve between the different bidding zone with the only constraint of interconnection capacities. In this respect, it is necessary to assess the risks in each country at ENTSO-E and ENTSO-G levels, develop a common action plan, and identify preventive measures in the short and long term.

The earlier reduction of CO_2 in 2027 as planned in the NRRP is possible at 17% higher prices but at lower operational costs.

Complete lignite closure in 2032 is relevant, due to the lower price spread between NRRP and Green ambition scenarios and the lower operational costs.

Table 7: Yearly CO_2

Scenarios / Target years	MtCO2		
	2023	2027	2032
National Energy and Climate Plan (NECP)	15,58	22,10	13,12
National Recovery and Resilience Plan (NRRP)		13,47	7,25
Green Ambition (lignite closure)			0,00
Gas crisis	16,93		

Note: Co-gen on gas not incl.

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In the Green ambition scenario, the Bulgarian bidding zone is turned into a big net importer (more than 20% of demand should be supplied by imports) instead of a net exporter, as it has been usually during the last two decades. This raises a diversification issue that should be considered when developing the Bulgarian energy strategy.

Table 8: Exchanges with neighbor bidding zones, [TWh]

Target years / Scenarios	2023		2027		2032	
	Export	Import	Export	Import	Export	Import
National Energy and Climate Plan (NECP)	-3,082	0,156	-8,451	0,034	-5,523	0,074
National Recovery and Resilience Plan (NRRP)			-4,798	0,622	-1,093	2,250
Green Ambition (lignite closure)					-0,680	8,316
Gas crisis	-4,427	0,188				

8.3. Comparison with ERAA 2021

The BGRAA 2022 adequacy results are consistent with the ERAA 2021 outcomes. Concerning market results, the regional scope of BGRAA doesn't cover the market coupling (SDAC & SIDC) in Europe as it is done in ERAA 2021. Nevertheless, the economic and ecological outcomes of BGRAA provide sufficient arguments in the decision-making process for further development of the Bulgarian energy sector and the setting of future emission targets.

9. CONCLUSIONS

No adequacy concerns in the Bulgarian bidding zone were detected in each set of 700 Monte-Carlo simulations for different scenarios and TYs. Even gas crisis, CO_2 reduction, and lignite fleet closure don't affect the adequacy of the Bulgarian bidding zone, respectively in the short, medium, and long term.

The Green ambition scenario raises a diversification issue that should be considered when developing the Bulgarian energy strategy. In addition, after lignite closure, the ancillary services should be provided by new limited energy resources, which have active and reactive power limitations (duration, subsequent activations and etc.) and need to be integrated with new innovative technologies that should simulate synchronous rotating mass, in order to provide voltage stability, reactive power balance and to prevent cascading outages in the transmission networks.

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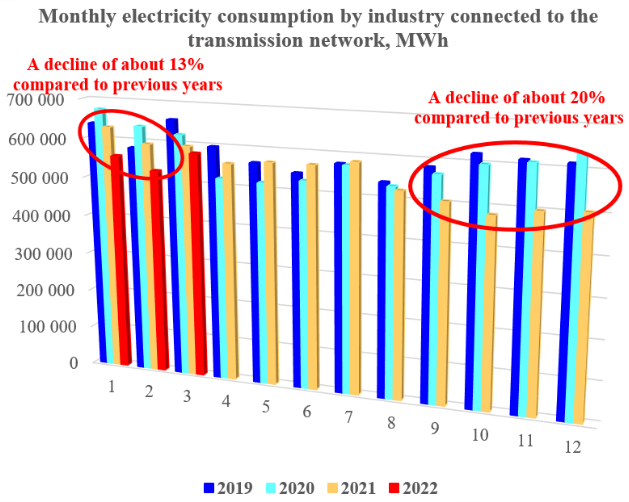
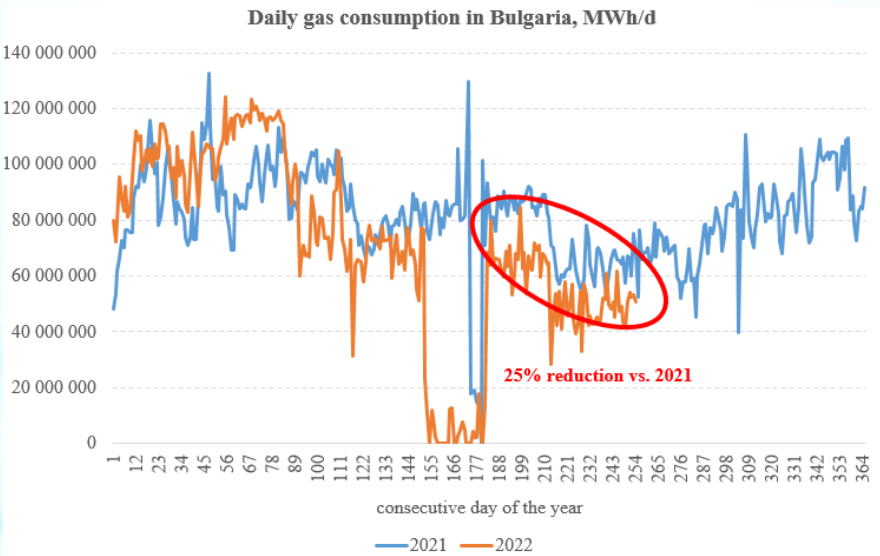
ANNEX I: Gas crisis scenario methodology

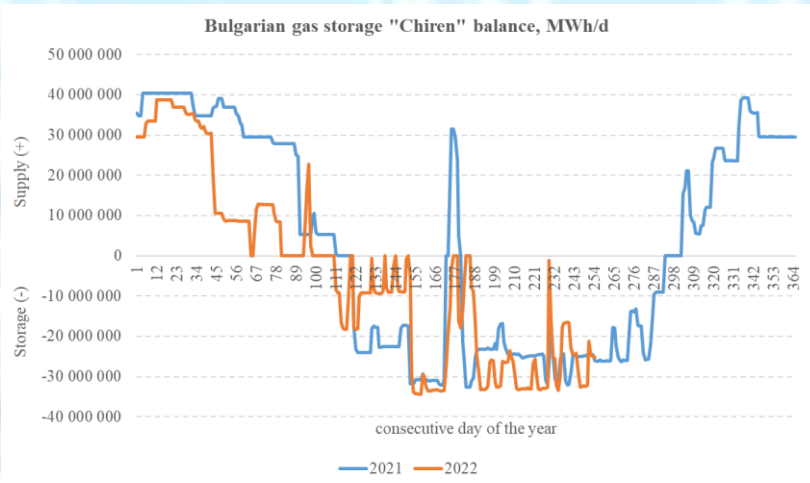
Some historic data



Source: ESO EAD



Source: ENTSO-G Transparency platform



Source: ENTSO-G Transparency platform

CHP operation assumptions

Co-generation and gas-fired district heating plants in the Bulgarian bidding zone maintain alternative fuels, such as gas oil and naphtha, which can be used by the respective boilers for the heat supply needs and can provide up to 60% of the heat load during the winter season. In addition, even in the event of a complete curtailment of gas supply, some of the cogeneration plants can use alternative fuels for limited electricity generation. Furthermore, the Bulgarian gas transmission network is connected to those of neighboring countries, which allows the use of alternative gas supply routes, as well as partial diversification of supply, insofar as Bulgaria is not currently entirely dependent on a single supplier. In other words, under any scenario, it cannot be expected that the entire heat load will be provided by increased electricity consumption. Due to the significant range of partial gas supply interruption scenarios and the myriad of combinations for securing the heat load, including through increased electricity consumption, the gas scenario with the following assumptions has been adopted for the purposes of the electricity system adequacy assessment:

- 100MW reduction in industrial users' electrical load;
- Reduction of electricity generation from Co-generation by 40% (currently in the Industrial co-gen the reduction is 25%);
- 40% of district heating clients (domestic and tertiary sector) switch to electric heating;
- 100% of clients (domestic and tertiary sector) using direct gas for heating switch to electric heating.

Space and water heating energy calculation

The input data for 2017 from the EC report[13] is used. The extreme case of 0% gas supply is considered.

- **<u>Households district heating</u>**

Dwellings (clients) number with district heating (CHP) is provided by the Ministry of Energy of Bulgaria[14]. District heating is deployed in the big cities and therefore multi-family homes (MFH) are considered. The annual final energy (including equipment losses) for water and space heating is used before conversion efficiency for heating (useful/final) for different types of equipment (heat pumps, boilers, ovens and etc.). The water heating is all year round and doesn't depend seasonally, while space heating starts when the daily average temperature is below around 18^{o}C [15]. Therefore, both types of heating energy, when district heating households switch to electricity, are calculated separately:

$$E_{H,SH} = \frac{N_{Dwell} * SFS * E_{H,spec}}{10^6}, \text{[TWh/a]} \qquad /1/$$

where:

$E_{H,SH}$ - annual energy for space heating in households that used district heating;
N_{Dwell} - dwellings (clients) number with district heating;
SPS - specific floor space in cities for MFH, [m^2/dwell.];

[13] Renewable space heating under the revised Renewable Energy Directive, ENER/C1/2018-494 - final report, https://op.europa.eu/en/publication-detail/-/publication/16710ac3-eac0-11ec-a534-01aa75ed71a1/language-en/format-PDF/source-261025885
[14] https://me.government.bg/files/useruploads/files/registri/dolkad_td&fdr-statistika-publikacija_08_07_15.pdf
[15] Eurostat, Heating and cooling degree days - statistics, https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Heating_and_cooling_degree_days_-_statistics#By_Member_State

$E_{H,spec}$ - space heating final energy for MFH, [kWh/m^2/a].

$$E_{H,WH} = \frac{N_{Dwell} * SFS * E_{W,spec}}{10^6}, [TWh/a] \qquad /2/$$

where:

$E_{H,WH}$ - annual energy for water heating in households that used district heating;
N_{Dwell} - dwellings (clients) number with district heating (CHP);
SPS - specific floor space in cities for MFH, [m^2/dwell.];
$E_{W,spec}$ - water heating final energy for MFH [kWh/m^2/a].

- **<u>Households directly using natural gas</u>**

The data concerning the number of households that directly use natural gas is not available. In the case of available data, the previously described calculations are applicable. An alternative approach for calculation is applied for Bulgarian case. The first step is a calculation of the ratio $R_{gas,CHP}$ between direct gas consumption E_{gas} and heat consumption by district heating for residential H_{CHP}:

$$R_{gas,CHP} = \frac{E_{gas}}{H_{CHP}}, [TWh/a] \qquad /3/$$

The total annual space and water heating, based on direct gas consumption, converted into energy is:

$$E_G = R_{gas,CHP} * \left(E_{H,SH} + E_{H,WH}\right), [TWh/a] \qquad /4/$$

In order to split water and space heating, the proportion between water and space heating final energy for MFH is used ($E_{H,spec}/E_{W,spec}$). Then the annual energy for space $E_{G,SH}$ and water $E_{G,WH}$ heating, when direct gas consumed households switch to electricity are:

$$E_{G,SH} = E_G * \frac{E_{H,spec}}{E_{W,spec} + E_{H,spec}}, [TWh/a] \qquad /5/$$

$$E_{G,WH} = E_G * \frac{E_{W,spec}}{E_{W,spec} + E_{H,spec}}, [TWh/a] \qquad /6/$$

- **<u>Tertiary sector - district heating by CHPs and direct gas usage</u>**

In case of no district heating by CHPs and direct gas usage, the schools and the universities will go online from home. Therefore, the energy for education ΣE_{Edu} has to be extracted. It can be expected that some portions $C_{ext,TR}$ and $C_{ext,Other}$, respectively of medium and large commercial areas and public administration, will not switch to electrical heating. The first is due to the lack of enough electrical equipment and the need for huge space heating, leading to additional investments, and the second is due to working online from home. Water heating is crucial for hotels, restaurants, and hospitals where the proportion between water and space heating final energy for MFH can be used ($E_{H,spec}/E_{W,spec}$). The rest types of the subtypes of the tertiary sector don't have significant sensitivity to water heating and can be neglected.

$$\Sigma E_{TER} = \Sigma E - \Sigma E_{Edu} - C_{ext,TR} * \Sigma E_{TR} - C_{ext,Other} * \Sigma E_{Other}, [TWh/a] \qquad /7/$$

where

ΣE_{TR} - annual energy for trade;
ΣE_{Other} - annual energy for other non-residential buildings;

ΣE - total annual energy for the tertiary sector.

The water $\Sigma E_{TER,WH}$ and space $\Sigma E_{TER,SH}$ heating in the tertiary sector, when switching to electricity in case of 0% gas supply, are as follows:

$$\Sigma E_{TER,WH} = (\Sigma E_T + \Sigma E_H) * \frac{E_{H,spec}}{E_{W,spec}+E_{H,spec}}, \text{[TWh/a]} \qquad /8/$$

$$\Sigma E_{TER,SH} = \Sigma E_{TER} - \Sigma E_{TER,WH}, \text{[TWh/a]} \qquad /9/$$

where

ΣE_T - annual energy for tourism;

ΣE_H - annual energy for health.

- **<u>Summary</u>**

Based on above mentioned the total energy for space $\Sigma E_{H\&TER,SH}$ and water $\Sigma E_{H\&TER,WH}$ heating in households and the tertiary sector in case of no gas supply are calculated:

$$\Sigma E_{H\&TER,SH} = E_{H,SH} + E_{G,SH} + \Sigma E_{TER,SH}, \text{[TWh/a]} \qquad /10/$$

$$\Sigma E_{H\&TER,WH} = E_{H,WH} + E_{G,WH} + \Sigma E_{TER,WH}, \text{[TWh/a]} \qquad /11/$$

Normalization of space heating energy. Down and Upscaling

Each time series of the electric loads corresponds to an average daily temperature time series. If the average daily temperature is below the base temperature (around 18°C), the difference defines the heating process. The aggregation of all such days defines annual data of heating degree days (HDD). The values vary year by year. The benchmark for normalization of final energy is the annual data of heating degree days (HDD) by country, provided by Eurostat[16].

The period covers only 10 years, but it can be accepted that its average value HDD_{ave} defines a normal heating year for each country. HDD_{min} and HDD_{max} define the extreme values for the period under consideration. Taking into account that available data used in the previous section refer to 2017, the normalization of annual space heating energy $\Sigma E^N_{H\&TER,SH}$ is calculated:

$$\Sigma E^N_{H\&TER,SH} = \Sigma E_{H\&TER,SH} * \frac{HDD_{ave}}{HDD_{2017}}, \text{[TWh/a]} \qquad /12/$$

Then upscaling and down scaling of the space heating energy for the temperature (corresponding load) time series *i*, will be:

$$\Sigma E^i_{H\&TER,SH} = \Sigma E^N_{H\&TER,SH} * \frac{HDD^i}{HDD_{ave}}, \text{TWh} \qquad /13/$$

Additional recalculation can be made in case of actual data (for the last year) concerning the trends of district heating and direct gas use, if available.

[16] Eurostat, Cooling and heating degree days by country - annual data, https://ec.europa.eu/eurostat/databrowser/view/nrg_chdd_a/settings_1/table?lang=en

Hourly distribution of additional load due to switching from gas to electricity

○ <u>Daily distribution of space and water heating energy</u>

The water heating daily distribution is accepted to be equal for all days during the year for each time series:

$$\Sigma E^{d}_{H\&TER,WH} = \frac{\Sigma E_{H\&TER,WH}}{365}, \text{ TWh} \qquad /14/$$

The daily space heating energy distribution is based on the share of daily $HDD^{d,i}$ to yearly $HDD^{y,i}$ for the time series i:

$$\Sigma E^{d,i}_{H\&TER,SH} = \frac{HDD^{d,i}}{HDD^{y,i}} \Sigma E^{i}_{H\&TER,SH}, \text{ TWh} \qquad /15/$$

○ *<u>Daily profiles of heating energy</u>*

Several pieces[17] of research were considered, but the most relevant profiles for space heating in the tertiary sector and households provides the research that covers more EU MS[18], including Bulgarian bidding zone.

The hourly demand factors (HDF) for space heating for both MFH and COM can be extracted take into account the ratio between space heating energy in households and tertiary sector ($\Sigma E_{TER,SH}/\Sigma E_{H,SH}$). Then for each hour h during the day d the distribution of daily space heating energy is:

$$\Sigma P^{h,i}_{H\&TER,SH} = \Sigma E^{d,i}_{H\&TER,SH} * HDF^{h}_{MFH,COM}, \text{ TWh} \qquad /16/$$

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[17] Pieces of research:

- Ruhnau, O., Hirth, L. & Praktiknjo, A. Time series of heat demand and heat pump efficiency for energy system modeling. Sci Data 6, 189 (2019). https://doi.org/10.1038/s41597-019-0199-y
- Runming Yao, Koen Steemers, A method of formulating energy load profile for domestic buildings in the UK, Energy and Buildings, Volume 37, Issue 6, 2005, Pages 663-671, ISSN 0378-7788, https://doi.org/10.1016/j.enbuild.2004.09.007
- https://www.esru.strath.ac.uk//EandE/Web_sites/17-18/gigha/heat-demand-profile.html
- Jenny Love, Andrew Z.P. Smith, Stephen Watson, Eleni Oikonomou, Alex Summerfield, Colin Gleeson, Phillip Biddulph, Lai Fong Chiu, Jez Wingfield, Chris Martin, Andy Stone, Robert Lowe, The addition of heat pump electricity load profiles to GB electricity demand: Evidence from a heat pump field trial, Applied Energy, Volume 204, 2017, Pages 332-342, ISSN 0306-2619, https://doi.org/10.1016/j.apenergy.2017.07.026.
- Ninoslav Holjevac, Tomislav Capuder, Igor Kuzle, Adaptive control for evaluation of flexibility benefits in microgrid systems, Energy, Volume 92, Part 3, 2015, Pages 487-504, ISSN 0360-5442, https://doi.org/10.1016/j.energy.2015.04.031.
- Schlemminger, M., Ohrdes, T., Schneider, E. et al. Dataset on electrical single-family house and heat pump load profiles in Germany. Sci Data 9, 56 (2022). https://doi.org/10.1038/s41597-022-01156-1
- David Fischer, Tobias Wolf, Johannes Scherer, Bernhard Wille-Haussmann, A stochastic bottom-up model for space heating and domestic hot water load profiles for German households, Energy and Buildings, Volume 124, 2016, Pages 120-128, ISSN 0378-7788, https://doi.org/10.1016/j.enbuild.2016.04.069

[18] Ruhnau, O., Hirth, L. & Praktiknjo, A. Time series of heat demand and heat pump efficiency for energy system modeling. Sci Data 6, 189 (2019). https://doi.org/10.1038/s41597-019-0199-y

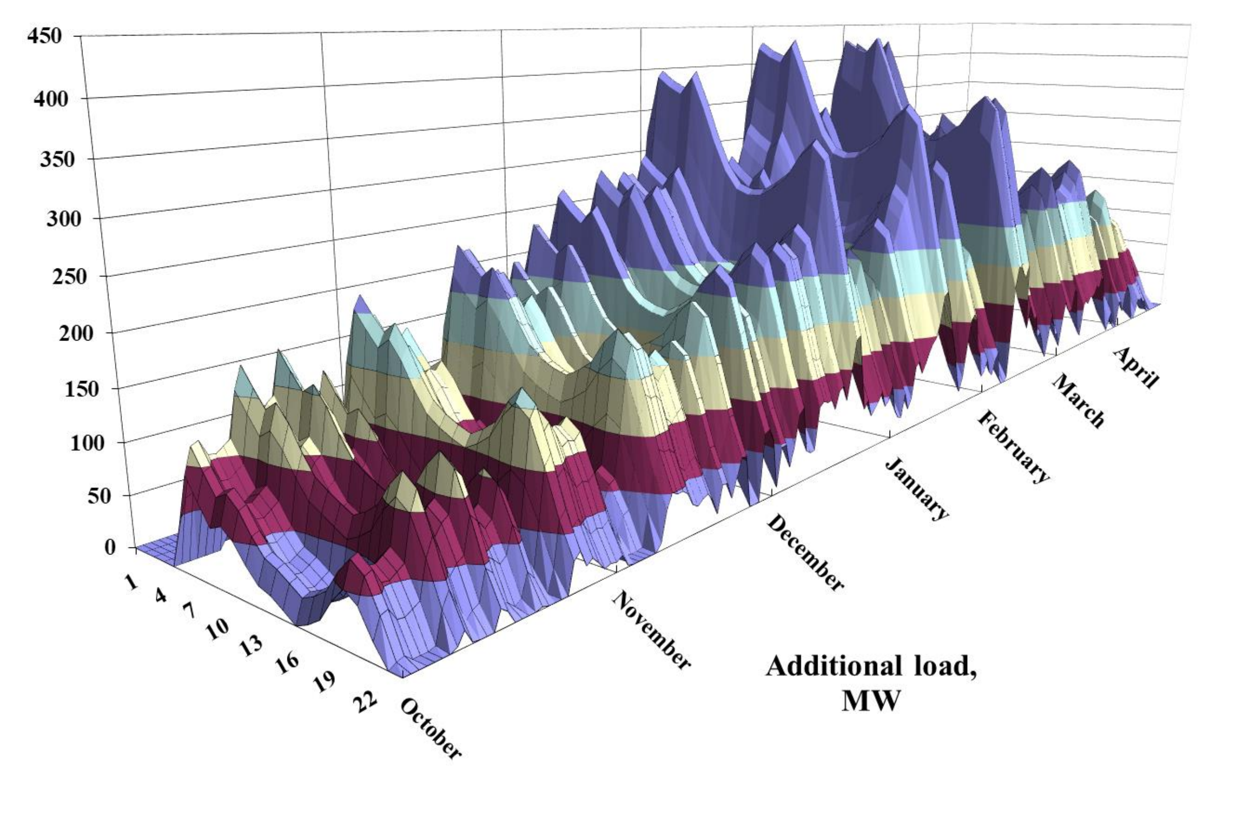
Concerning water heating, HDF_W are extracted from the most relevant research[19].

$$\Sigma P^{h,i}_{H\&TER,WH} = \Sigma E^{d,i}_{H\&TER,WH} * HDF^{h}_{W}, \text{TWh} \qquad /17/$$

The sum of $\Sigma P^{h,i}_{H\&TER,SH}$ and $\Sigma P^{h,i}_{H\&TER,WH}$ represents the hourly additional load in case of 0% gas supply in households and tertiary sector. In the case of a partially curtailed gas supply, these values have to be recalculated by the relevant coefficient $C_{gas,curt}$, respectively multiplied by (100% - $C_{gas,curt}$).

If there are available actual daily space and/or water heating profiles, the respective HDF should be updated.

Example – Additional load winter period CYs 2022-2023



[19] David Fischer, Tobias Wolf, Johannes Scherer, Bernhard Wille-Haussmann, A stochastic bottom-up model for space heating and domestic hot water load profiles for German households, Energy and Buildings, Volume 124, 2016, Pages 120-128, ISSN 0378-7788, https://doi.org/10.1016/j.enbuild.2016.04.069.

ANNEX II: Detailed results for Bulgarian bidding zone - Gas crisis 2023; NRRP 2027 and Green ambition 2032

Net energy balances, [MWh]

- ***Gas crisis 2023***

Net Generation							Net Demand			Import	Export
NPP	Co-gen & Biomass	Lignite	HPP	Wind	PVs	TOTAL	without Pumps	Pumps	TOTAL		
15 702 340	2 303 385	14 519 620	3 712 489	1 404 279	1 910 562	**39 552 675**	35 313 713	0	**35 313 713**	**188 338**	**4 427 300**

- ***NRRP 2027***

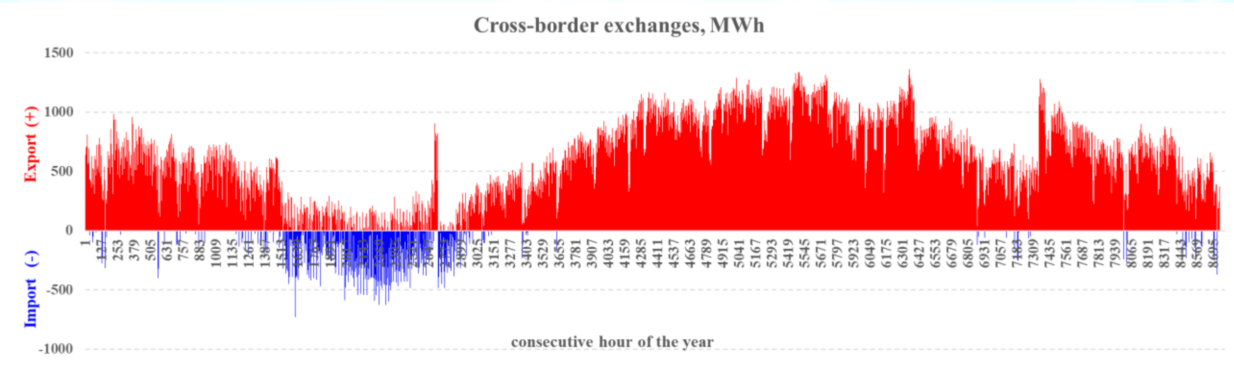
Net Generation								Net Demand				Import	Export
NPP	Co-gen & Biomass	Lignite	HPP	Wind	PVs	Battery discharge	TOTAL	without Pumps	Pumps	Battery charge	TOTAL		
15 757 366	3 562 604	10 347 316	4 103 782	2 875 973	5 532 580	1 260 759	**43 440 380**	37 281 891	559 664	1 422 883	**39 264 438**	**622 323**	**4 798 265**

- ***Green ambition 2032***

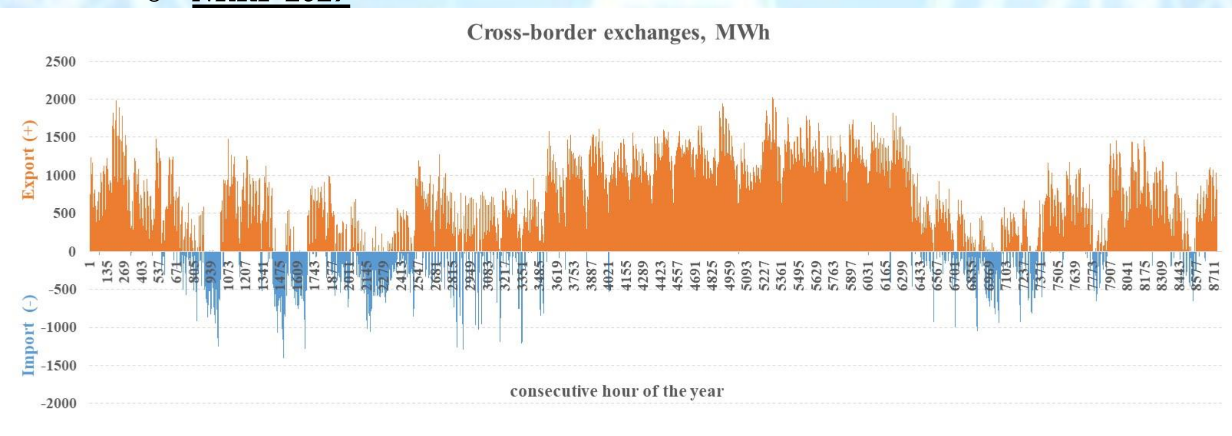
Net Generation								Net Demand				Import	Export
NPP	Co-gen & Biomass	Lignite	HPP	Wind	PVs	Battery discharge	TOTAL	without Pumps	Pumps	Battery charge	TOTAL		
15 877 509	3 676 705	0	3 564 219	3 042 201	5 524 928	1 096 342	**32 781 904**	38 740 619	460 583	1 218 172	**40 419 374**	**8 316 581**	**679 111**

Cross-border exchanges

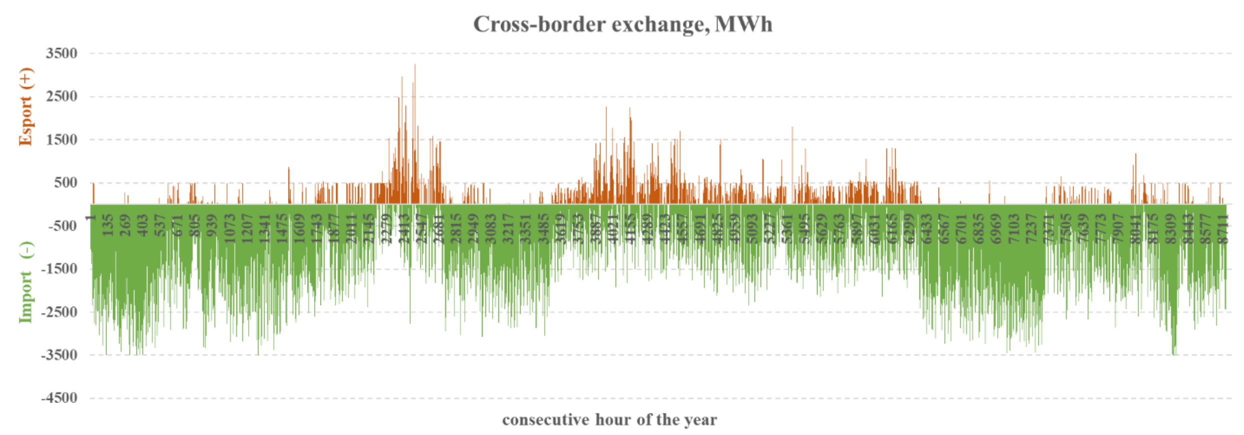
- ***Gas crisis 2023***



- ***NRRP 2027***



- *__Green ambition 2032__*

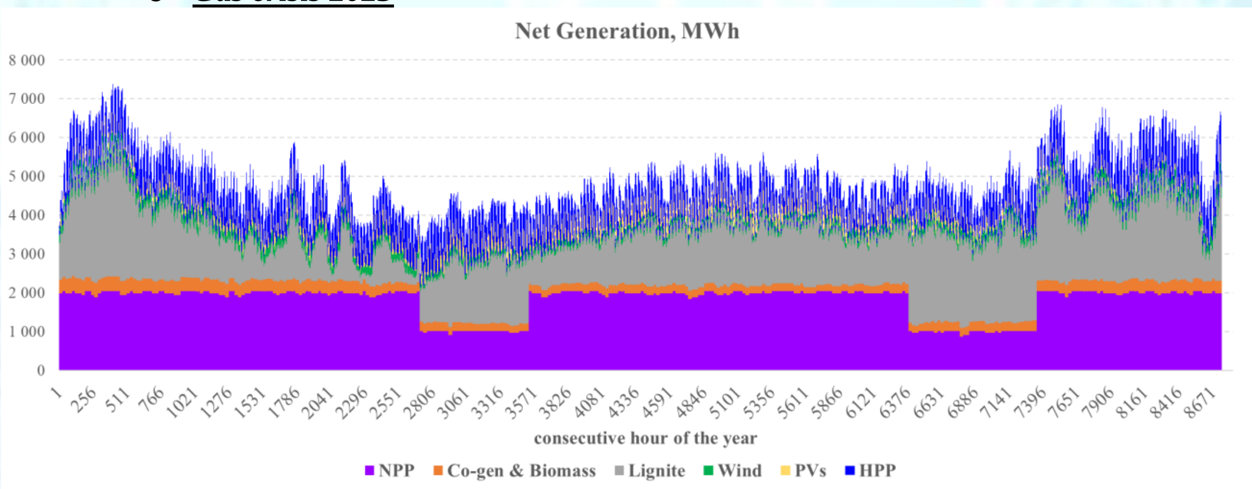


Spill energy (generation surplus curtailment)

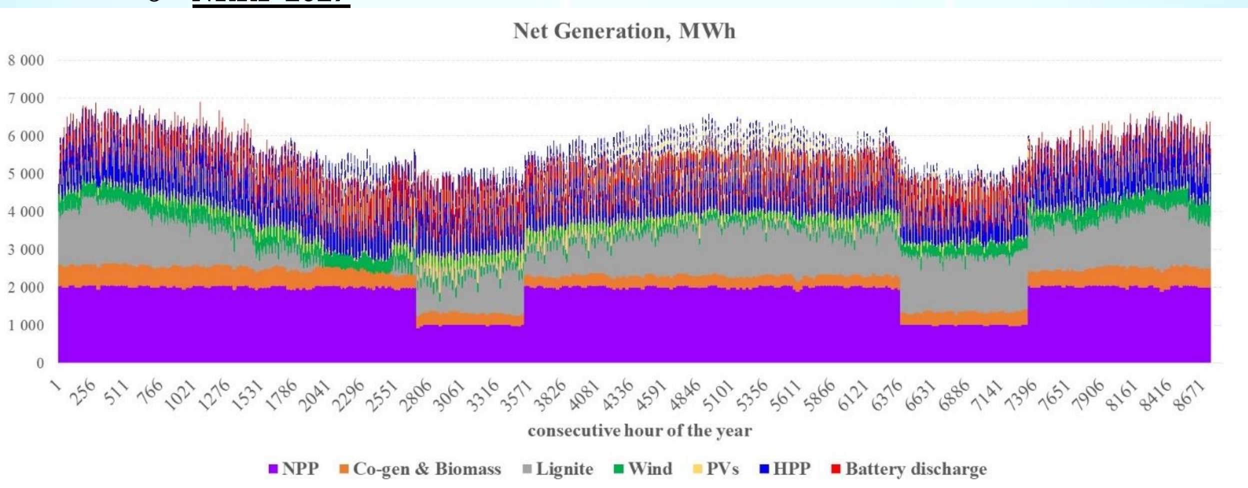
- *__Gas crisis 2023 – No spill of energy__*
- *__NRRP 2027 – No spill of energy__*
- *__Green ambition 2032 – No spill of energy__*

Generation hourly profiles

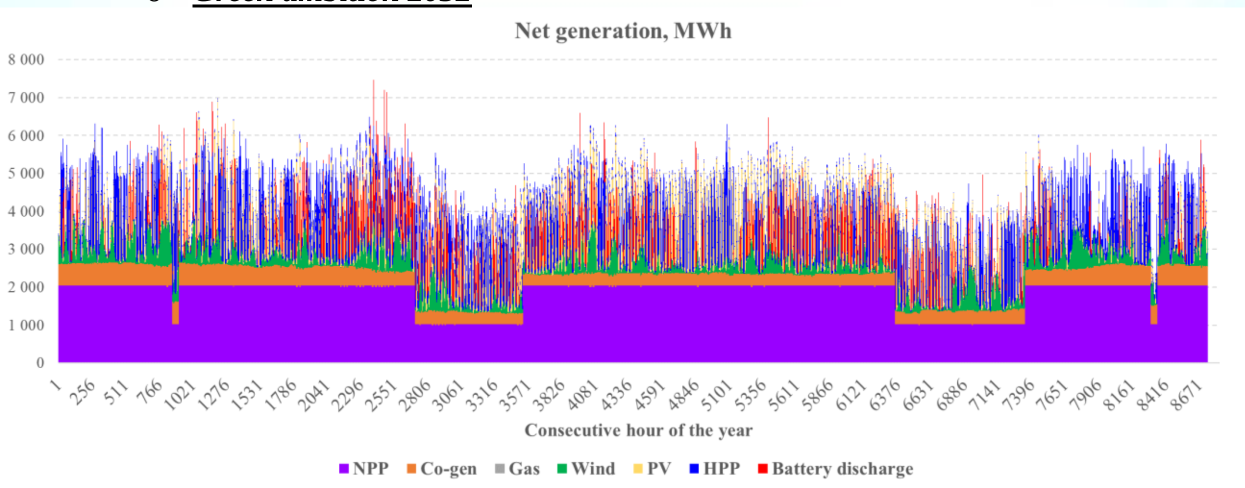
- *__Gas crisis 2023__*



- *__NRRP 2027__*

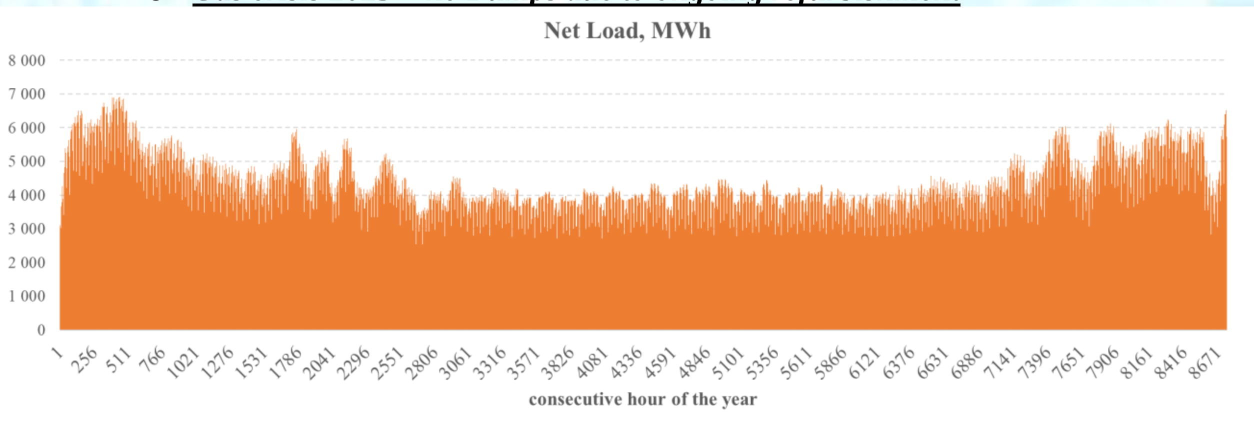


- *__Green ambition 2032__*

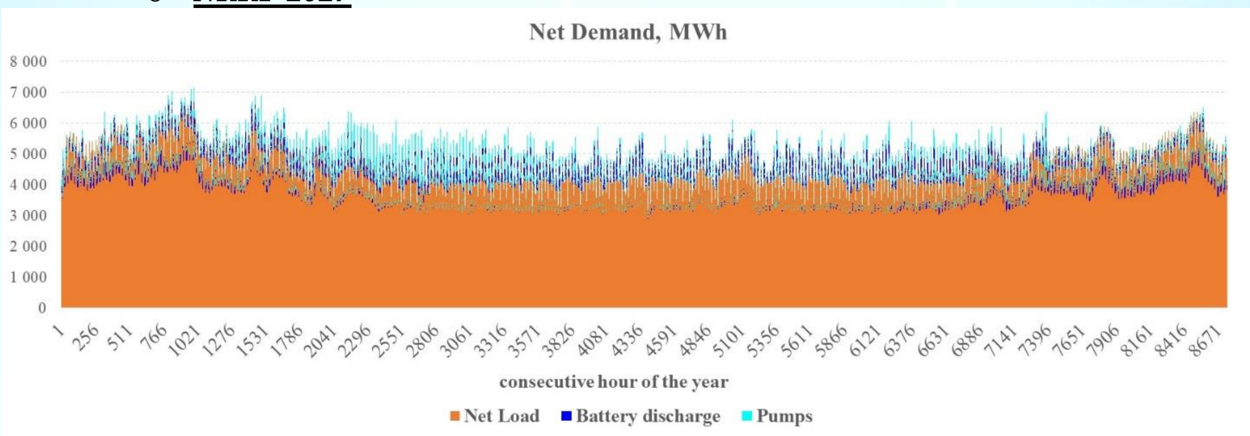


Load and Pumps profiles

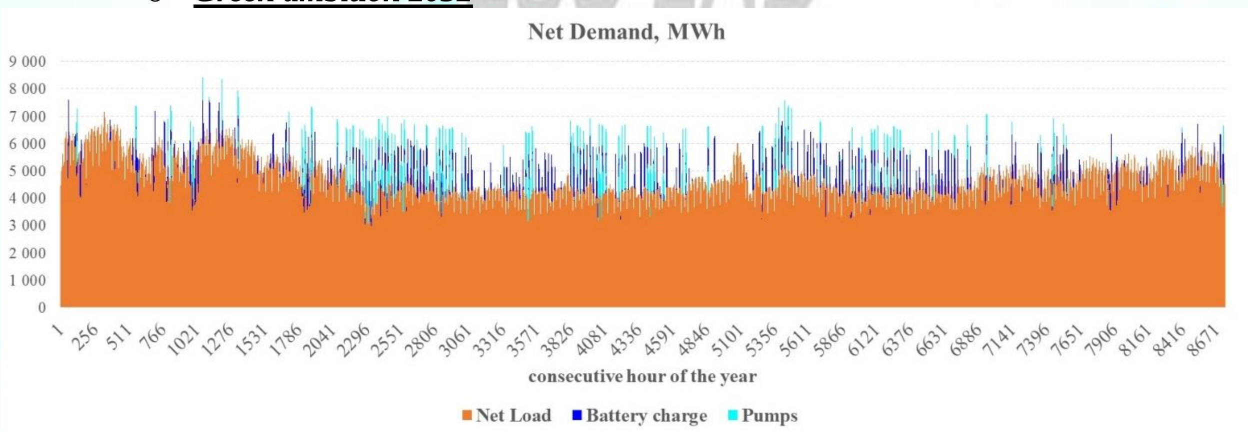
- *__Gas crisis 2023 – no Pumps due to ongoing refurbishment__*



- *__NRRP 2027__*



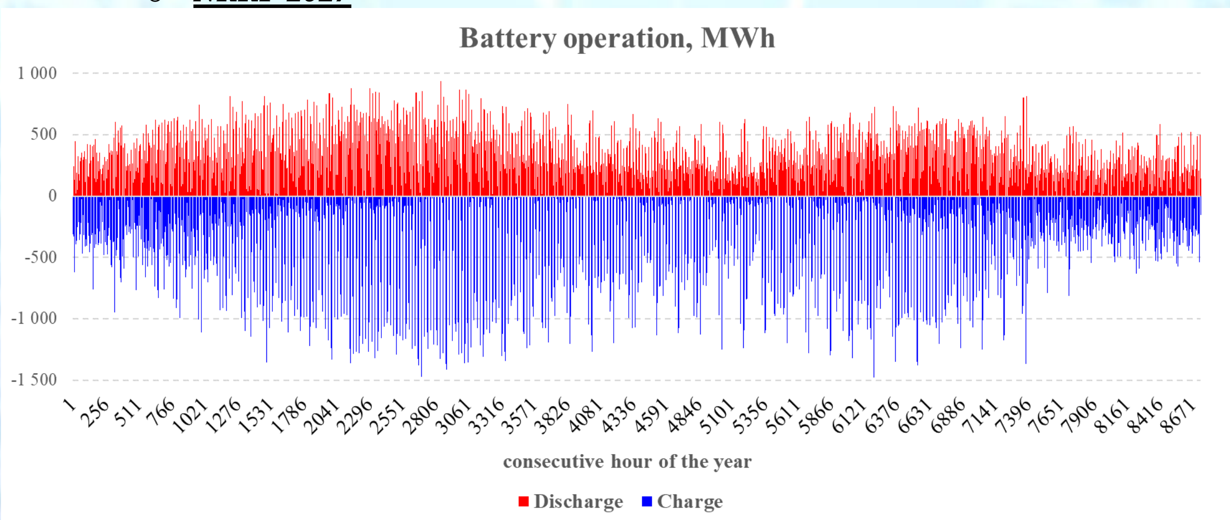
- *__Green ambition 2032__*



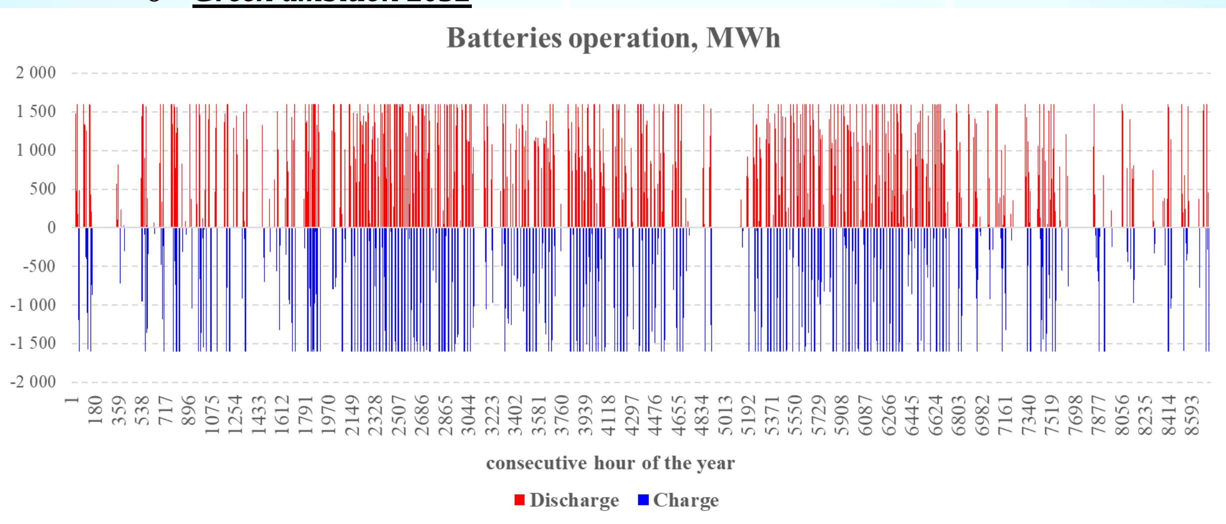
Battery profiles

- *__Gas crisis 2023 – No battery installed__*

- *__NRRP 2027__*

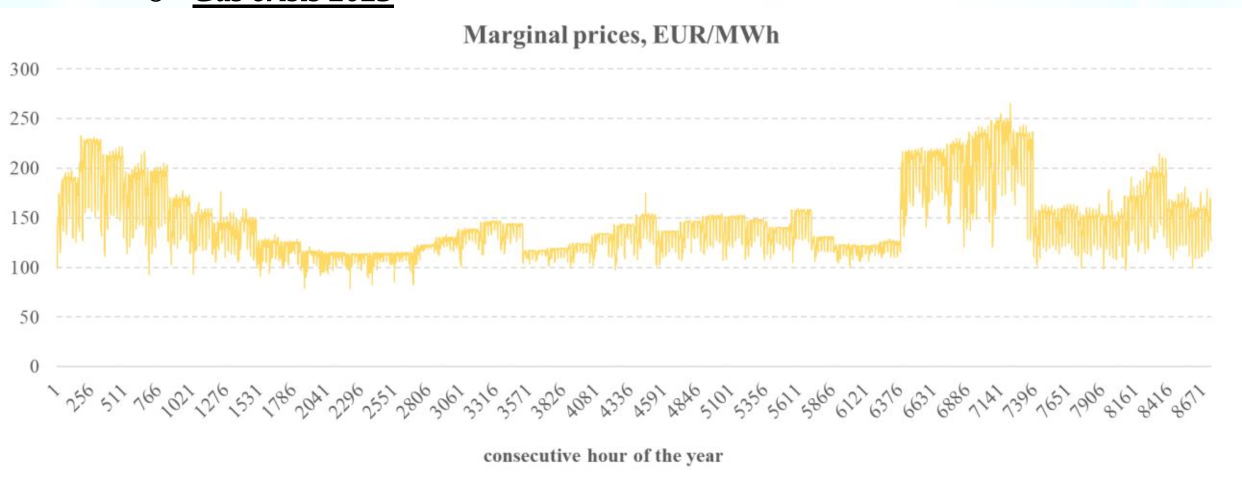


- *__Green ambition 2032__*

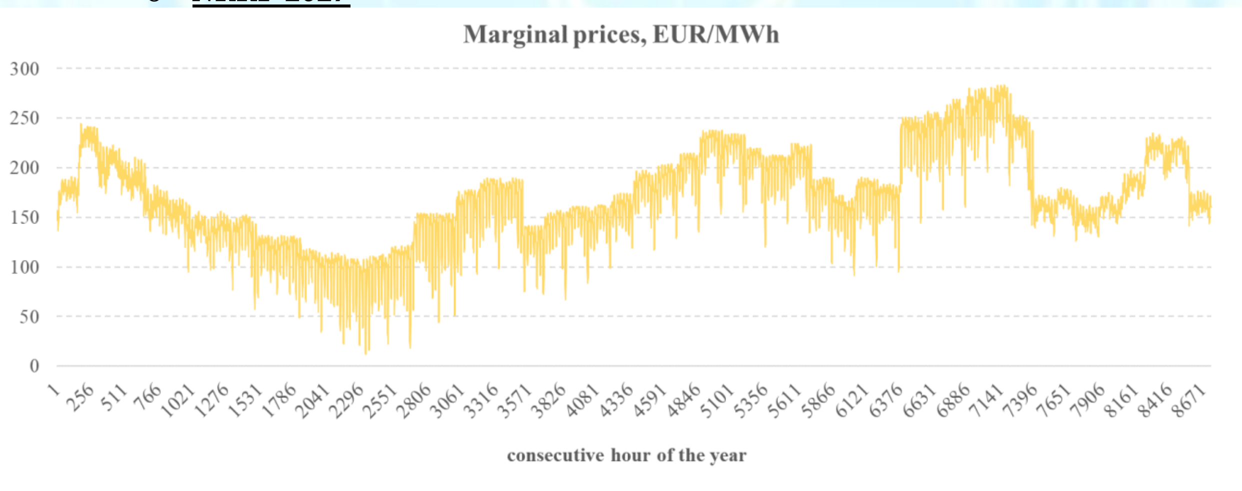


Hourly marginal prices

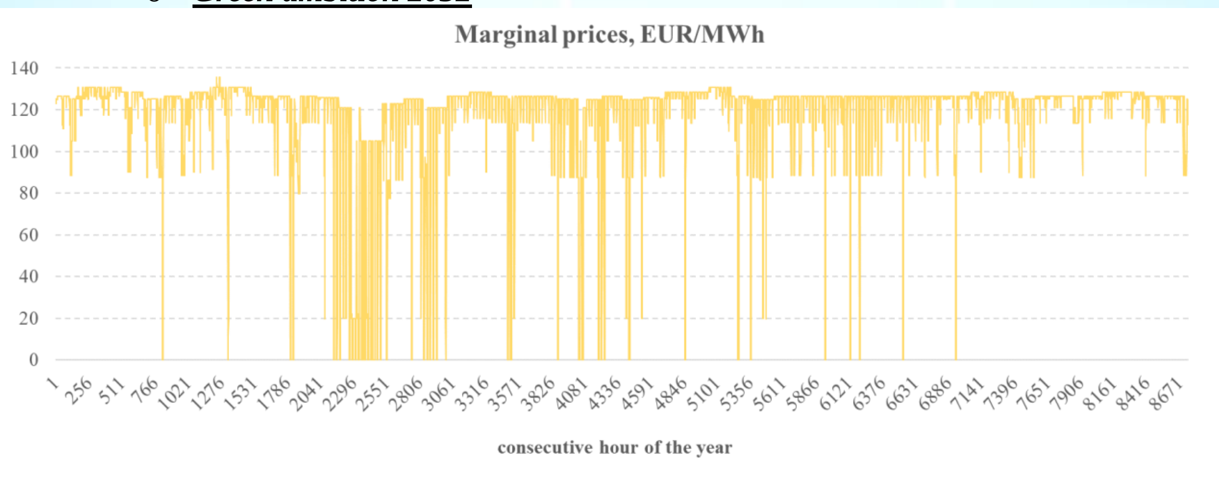
- *__Gas crisis 2023__*



- *__NRRP 2027__*

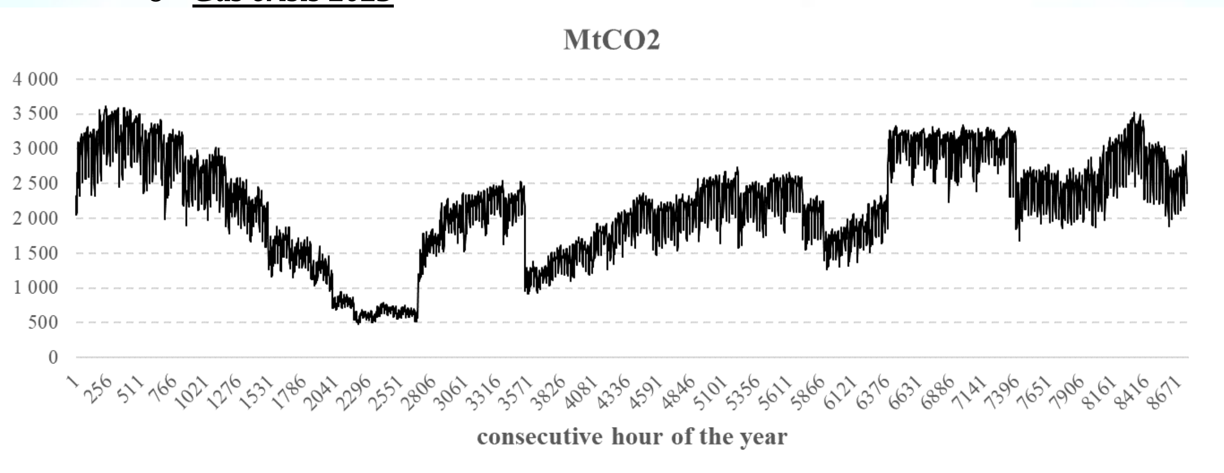


- *__Green ambition 2032__*

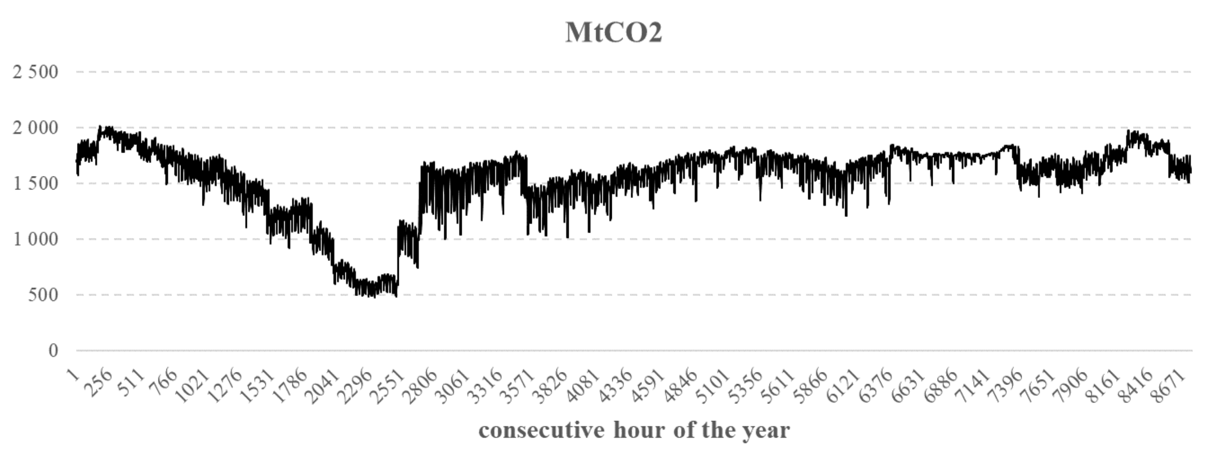


Hourly emitted CO_2

- *__Gas crisis 2023__*



- *__NRRP 2027__*



- *__Green ambition 2032 – No CO_2 (only lignite are considered)__*

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