**INVESTIGATION OF THE EFFECT OF BEHIND-THE-METER BATTERY ENERGY STORAGE SYSTEMS (BESS) ON THE GREEK WHOLESALE ELECTRICITY MARKET AND ON THE TOTAL RETAILERS’ WHOLESALE MARKET COST IN THE YEAR 2025**

***Full Report***

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# Terms and Abbreviations

|  |  |
| --- | --- |
| **Term / Abbreviation** | **Definition** |
| BESS | Battery Energy Storage System |
| CCGT | Combined Cycle Gas Turbine |
| DAM | Day-Ahead Market |
| DAPEEP | RES plants & Guarantees of Origin Operator |
| EEFORd | Effective Equivalent Demand Forced Outage Rate |
| FCR | Frequency Containment Reserve |
| FRR (a/m) | Frequency Restoration Reserve (a: automatic, m: manual) |
| HENEX | Hellenic Energy Exchange |
| IPP | Independent Power Producer |
| IPTO (ADMIE) | Independent Power Transmission Operator (ADMIE) |
| ISP | Integrated Scheduling Process |
| LP | Linear Programming |
| LTSx | Long-Term Scheduling Extended |
| MVC | Minimum Variable Cost |
| MILP | Mixed Integer Linear Programming |
| NECP | National Energy and Climate Plan |
| NTC | Net Transfer Capacity |
| PPC | Public Power Corporation |
| PSP | Pumped Storage Plant |
| PX | Power Exchange |
| RAE | Regulatory Authority for Energy |
| RES | Renewable Energy Sources |
| RTBEM | Real-Time Balancing Energy Market |

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# Introduction – Project Scope

The scope of the present study is the investigation of the effect that the introduction of Battery Energy Storage Systems (BESS) would have on the operation of the Greek wholesale electricity market and the total wholesale market cost for the electricity Retailers and, subsequently, the end-consumers for the year 2025.

This study was carried out for the Panhellenic Federation of Photovoltaic Electricity Producers Associations (in Greek: “Πανελλήνια Ομοσπονδία Συλλόγων Παραγωγών Ηλεκτρικής Ενέργειας από Φωτοβολταϊκά – ΠΟΣΠΗΕΦ”).

Specifically, in this study we quantify the effect that the introduction of 1000 MW of BESS would have on the outcome of the Greek wholesale electricity market in terms of the market clearing prices as well as on the projected total wholesale market cost for the electricity Retailers for the year 2025. For the purposes of this study, the total wholesale market cost for electricity retailers comprises the following components:

* *Day-ahead market electricity procurement cost:* This is the electricity procurement cost undertaken by the Retailers for buying electricity directly from the DAM. For the scope of this study, it has been considered that Retailers will exclusively use this option in order to fully cover their electricity retail portfolio needs (end-consumers).
* *Uplift Account Charges (UAs):* These are additional charges that have to be undertaken by all Retailers to compensate for the transmission system losses costs (UA-1), the reserves provision costs (UA-2) and the balancing market financial neutrality costs (UA-3). The latter is used to allocate to Balance Responsible Parties (BRPs) any remaining balance after the calculation of the debits and credits calculated by the Greek TSO for the activated balancing energy for mFRR and aFRR, the energy activated for purposes other than balancing and Imbalance Settlement.

In this framework, we performed the required analysis considering a probable scenario regarding the evolution of the most significant electricity market and system parameters, namely system load demand, RES installed capacity, natural gas prices, CO2 prices, future conventional generating units’ availability, etc. for the year 2025.

Two (2) simulation scenarios were formulated and executed, which are differentiated solely in terms of the installed capacity of BESS that will be operational in the Greek interconnected power system in 2025: In Scenario 1, no BESS are considered to operate in the Greek power system (zero BESS capacity), whereas in Scenario 2, 1000 MW of 2-h BESS are considered to be fully operational during the entire year.

The analysis of the simulation results indicates in quantitative terms the cost savings that could be obtained for the end-consumers during 2025 by the presence and full operation of BESS in the Greek wholesale electricity market.

The remainder of this report is as follows: Chapter 2 presents in detail the main assumptions, the analytical input data used in the mid-term simulations of the Greek wholesale electricity market and the simulation methodology. Chapter 3 presents the simulation results along with an ex-post analysis regarding the estimation of the potential cost savings for the end-consumers on the basis of these simulation results. Chapter 4 contains the bibliography used in this study, while Chapter 5 is the Annex of the study.

# Greek Wholesale Electricity Market and Balancing Market Simulation for the year 2025

## Introduction

Since November 1st, 2020 the Greek wholesale electricity market has been transformed from a centralized mandatory pool (where the Market Operator solved on a daily basis a short-term unit commitment problem for the following day (also known as “Day-Ahead Scheduling” or DAS), performing co-optimization of energy and reserves (primary, secondary)) to a decentralized market, based on the establishment of a simple voluntary day-ahead Power Exchange (PX). Hellenic Energy Exchange (HEnEx) is currently the Operator of the Energy Derivatives Market, the Day-Ahead Market and the Intra-Day Market (according to the provisions of the Energy Derivatives Market Rulebook [1] and the Day-Ahead Market & Intra-Day Market Trading Rulebook [2] that is compliant with the provisions of the European Target Model). In addition, the conclusion of bilateral contracts between the market participants (e.g. producers, suppliers, traders, RES Aggregators, etc.) for the sale of electricity constitutes a basic feature of the new target model, in parallel with the operation of the PX.

In the restructured Day-Ahead Market, the participants (e.g. producers, suppliers) submit simple energy quantity (MWh)-price (€/MWh) offers/bids (hybrid orders) and block orders for the energy they want to sell/buy for each hour of the next day. Additionally, producers are allowed to submit block orders (multi-hourly products to sell electricity) in order to obtain feasible operation schedules for their units during the dispatch day. The Market Operator (MO) creates the aggregated supply and demand curves and clears the DAM, without considering any unit operating constraint neither the system reserve requirements.

Once the initial solution of the DAM is acquired, the System Operator (ADMIE) executes a centralized scheduling model (where the cleared import/export/pumping quantities yielded from the DAM solution are considered as fixed input data), taking into account the precise techno-economic data of the production units (e.g. technical operating limits, minimum up/down time, operating limits under Automatic Generation Control, system reserve requirements, etc.). This model is called “Integrated Scheduling Process (ISP)” and it is also used in this study for the determination of the unit commitment. Following ISP, a Real-Time Balancing Energy Market (RTBEM) takes place, where a Linear Programming (LP) model that provides the dispatch instruction to every Balancing Service Provider (e.g. conventional units and/or RES dispatchable portfolios and/or Load dispatchable portfolios, etc.) is solved every 15-min during the day. This market sequence is based on the current Greek electricity market regulatory framework and is also used in this study.

## Mid-term simulation model of the electricity market

Two methods are widely used for the simulation of the wholesale electricity market: a) the analytical method, and b) the chronological method.

The first method uses the load duration curve at an annual level and the price duration curve of a power market, in order to attain the production and operation hours of each unit, according to the variable cost of the corresponding technology (with given fuel cost and CO2 prices). This method provides approximate results since it disregards the actual operation of the power system.

The second method simulates chronologically the real market operation, solving the daily optimization problem of the objective function regarding a day-ahead market. This method provides more accurate results and, therefore, it is used in this study.

For the purposes of this study, an analysis of the future full implementation of the Greek electricity market has been performed using the specialized software platform “Long-Term Scheduling” (LTSx). This software can simulate in detail the wholesale market and the Balancing Market in a mid-/long-term horizon (ranging from one month to several years in the future), by solving sequentially:

1. The Day-Ahead Market (DAM)
2. The Integrated Scheduling Process (ISP), and
3. The Real-Time Balancing Energy Market (RTBEM)

In this study, the above optimization problems are solved on a day-by-day basis under suitable time steps i.e. 1 hour for DAM, 30-min for ISP and 15-min for RTBEM for the entire year 2025.

## Input Data

In this Section, the input data of the simulation software that are used in the simulation cases are presented. These data comprise the units’ (thermal, hydro, RES, BESS, PSP) basic technoeconomic data, data that define the Greek interconnected power system and its physical characteristics, as well as data related to the electricity market. It is noted that the data described in the following Sections correspond merely to the interconnected system, unless otherwise stated.

The data taken into account for the formulation of the present long-term energy scheduling problem are the following:

1. the system load and the load of each operating zone
2. the RES energy injections
3. the pumping schedule of the pumped-storage stations
4. the inter-zonal constraints between Mainland-Crete and the other insular power systems that will be interconnected
5. the operation of new units and the withdrawal of old units
6. the generating units’ technoeconomic data (including the thermal units’ emissions cost)
7. the equivalent forced outage rate and the periods of the units’ schedule maintenance
8. the units’ energy offers, which take into account the fuel costs and the CO2 emissions costs as well as potential bidding strategies that will be implemented in the DAM, ISP and RTBEM in order to maximize their energy revenues
9. the mandatory hydro injections
10. electricity flow on cross-border interconnections

The technical maximum, the equivalent forced outage rate and the maintenance schedule of each unit determine the maximum availability that is taken into account in the solution of the long-term energy scheduling problem.

### System Load

In general, the total electricity consumption as well as the peak load demand of the Greek interconnected power system is expected to increase significantly from 2024 onwards, not only due to the anticipated positive prospects of the Greek economy but also due to the scheduled interconnections of almost all Greek insular power systems with the mainland. Specifically, according to the latest Ten-Year Network Development Plan 2024-2033 of ADMIE that was recently set in public consultation by the Regulatory Authority for Energy (RAE) in 27/10/2023 [3], until the end of 2025 the islands that will be fully interconnected with mainland Greece comprise Crete (mid-2024) and West Cyclades (2025).

A single (1) scenario regarding the total electricity consumption and the peak load forecast of the Greek power system for the year 2025 has been considered, which is based on the NECP Scenario of the Ten-Year Network Development Plan 2024-2033 of ADMIE [3]. However, the recent energy crisis has resulted in a surge of the end-consumers electricity bills, which, in turn, has led to a drastic decrease of the total electricity consumption during the last twelve months (~ -6.0% with respect to the previous 12-month period). In parallel, taking into account the urgent EU measures to ensure the security of energy supply in the entire EU in the forthcoming years, we considered a mild and gradually decreasing drop of the electricity consumption (in TWh and MWp) in the forthcoming years as compared to the TYNDP 2024-2033 forecasts. In this context, the total electricity consumption of 2025 has been considered equal to **55.0 TWh** and the peak load forecast has been considered equal to **10,471 MW**.

The monthly electricity consumption of the Greek interconnected power system during the year 2025 is illustrated in Figure 2‑1.



***Figure 2‑1.*** *Electricity consumption of the Greek interconnected power system during 2025*

### RES Installed capacity

A single scenario regarding RES installed capacity has been formulated. The projected installed capacity per RES technology for each month of the study is shown in Table 2‑1 and follows relevant estimations made by the author of this report on the basis of the current market trend, especially as regards the wind and PV plants’ penetration. It is also noted that in the framework of this study the operation of a new solar-thermal power plant with installed capacity of 52 MW that will be constructed in Crete has been taken into account. The connection of this plant is scheduled for late 2024 and for the purposes of this study it is taken into account in the simulations.

The projected hourly injections per RES technology for each hour of the scheduling period are derived by multiplying relevant historical hourly profiles (in MWh injected/installed MW) with the projected installed capacity per RES technology, as shown in Table 2‑1.

The projected hourly injections of RES are inserted as simple hybrid offers (with zero energy offer price) in the optimization models of the LTSx simulation software, according to the modeling and solution rules of the Greek wholesale electricity market. Table 2‑2 presents the projected total annual electricity injections (in MWh) per RES technology for the year 2025.

**Table 2‑1. Forecasted installed capacity per RES technology for the year 2025**

| **Month** | **Wind Capacity [MW]** | **Small Hydros [MW]** | **Biomass / Biogas [MW]** | **PVs (ground-mounted) [MW]** | **PVs** **(roof-mounted) [MW]** | **Small Co-generation [MW]** | **TOTAL [MW]** |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **January** | 5,311 | 289 | 157 | 7,902 | 371 | 141 | **14,171** |
| **February** | 5,331 | 289 | 159 | 8,032 | 371 | 141 | **14,322** |
| **March** | 5,351 | 289 | 160 | 8,162 | 371 | 141 | **14,474** |
| **April** | 5,371 | 289 | 162 | 8,292 | 371 | 141 | **14,625** |
| **May** | 5,391 | 289 | 163 | 8,422 | 371 | 141 | **14,777** |
| **June** | 5,411 | 289 | 165 | 8,552 | 371 | 141 | **14,928** |
| **July** | 5,431 | 290 | 166 | 8,682 | 371 | 141 | **15,081** |
| **August** | 5,451 | 290 | 168 | 8,812 | 371 | 141 | **15,232** |
| **September** | 5,471 | 290 | 169 | 8,942 | 371 | 141 | **15,384** |
| **October** | 5,491 | 290 | 171 | 9,072 | 371 | 141 | **15,535** |
| **November** | 5,511 | 290 | 172 | 9,202 | 371 | 141 | **15,687** |
| **December** | 5,531 | 290 | 174 | 9,332 | 371 | 141 | **15,838** |

**Table 2‑2. Forecasted annual injections per RES technology**

|  |  |
| --- | --- |
| **RES Technology**  | **Annual Injections [MWh]** |
| Wind | 12,025,442 |
| PV (Ground & Roofs) | 13,553,625 |
| Biogas / Biomass | 769,176 |
| Small Hydros | 737,832 |
| Small Cogeneration | 275,400 |
| Solar Thermal | 143,368 |
| **TOTAL** | **27,504,843** |

### Construction/Withdrawal of conventional generating units

The timeline and processes regarding the construction of new thermal generating units have been based on the published business plans of power producers in Greece. Furthermore, it has been considered that all existing lignite units (except for the new lignite unit Ptolemaida 5) will extend their lifetime until 2025 (following relevant Decisions of the Ministry of Energy and Environment that were issued on 27/12/2021 [4] and 14/12/2022 [5]), instead of their premature decommissioning by the end of 2023, as initially planned. The new lignite unit Ptolemaida 5 is considered to continue operating as a lignite unit by the end of 2028 and then be permanently withdrawn following the provisions of the National Climate Law 4936/2022, which requires that electricity generation produced by solid fossil fuels will be prohibited after 31/12/2028 and the associated generating units’ production licenses cease to apply after that date [6].

Based on these assumptions, for the purposes of this study a probable scenario regarding the evolution of the thermal generation mix has been formulated accordingly. Specifically:

1. Lignite Units: The assumed withdrawal schedule for the seven existing lignite plants that are still available is as follows:
* Ag. Dimitrios 1-2 are going to be decommissioned on 30/06/2025.
* Ag. Dimitrios 3-5, Megalopoli 4 and Meliti are going to be decommissioned on 31/12/2025.

The new lignite unit Ptolemaida 5 has already entered into commissioning operation since December 2022 and is expected to enter into commercial operation soon. Based on the aforementioned discussion, for the purposes of this study the new lignite unit Ptolemaida 5 is considered to be fully available during the entire 2025.

1. Combined-Cycle Gas Turbines (CCGT) Units:

Currently, there are two new CCGT units that either have already entered commissioning operation or are in advanced construction phase, as follows:

* The new gas-fired generating unit of Mytilineos Group in Viotia, which was granted a production license in March 2019 (NCAP ≈ 806 MW, net efficiency ≈ 63.0%), has entered commissioning operation in early 2023 and is expected to enter commercial operation soon.
* The new gas-fired generating unit of TERNA-MORE joint venture in Rodopi, which was granted a production license in June 2019 (NCAP ≈ 858 MW, net efficiency ≈ 63%) and is currently in advanced construction phase, is considered to enter into commercial operation in September 2024.

Based on the above, both these new CCGT units are considered to be fully available during the entire year 2025.

1. Combined Heat and Power (CHP) Plants: Besides the existing CHP plant of Mytilineos Group that operates baseload at 127.9 MWel, a new gas-fired CHP plant (Kardia CHP) with net capacity equal to 105 MWel is considered to be constructed by PPC in Western Macedonia and enter commercial operation in October 2024 to meet the district heating needs of the region, once the existing lignite units that are currently in charge of this service are decommissioned. In the framework of this study, this new plant is considered to follow a baseload generating profile (i.e. constant power output at 90 MWel/h) for ~5,000 hours/year (operation period: 01/10 – 30/04) during 2025.
2. Other thermal units: Once the full interconnection of Crete with the mainland enters into commercial operation (mid-2024), the entire net system load of Crete is expected to be undertaken by the generating units’ fleet that is located in mainland. However, for the purposes of this study, it is considered that the five most efficient generating units currently operating in Crete, namely the four units in the Atherinolakkos power station (Atherinolakkos Steam units 1,2 and ICE units 1, 2) and the CCGT unit located in Chania, will continue to be available until the end of 2030 (31/12/2030) in cold reserve to support the operation of the Cretan power system in case of emergency. For the purposes of this study, these five thermal generating units have been considered as fully available during the year 2025.
3. Hydro Units: Besides the existing hydro system that comprises 16 large hydroplants with a total installed capacity of 3171 MW, the total hydro installed capacity of the Greek power system will be increased by 29 MW in January 2025 following the commercial operation of the new hydro unit “Metsovitiko”.

The evolution of the conventional (thermal & hydro) generation capacity of the mainland in monthly analysis during 2025 is illustrated in Figure 2‑2. The analytical timeline for the construction/withdrawal of the conventional (thermal & hydro) generating units until the end of 2025 is presented in Table 5‑1 of the Annex.



***Figure 2‑2.*** *Evolution of conventional generation capacity*

### Energy Storage Systems

In this study it is assumed that BESS will be incorporated into the Greek interconnected power system and be commercially available during 2025. Two (2) distinct scenarios have been formulated regarding BESS penetration, as follows:

* Base Scenario: In this scenario, zero BESS capacity has been considered during the entire year 2025.
* High Scenario: In this scenario, 1000 MW of BESS are considered to be fully operational during the entire year.

All BESS units are considered to have a 2-h energy capacity and overall round-trip efficiency equal to 88%. Their daily operation in the wholesale and balancing markets was simulated similarly to the rationale that is currently adopted for pumped-storage plants (i.e. they absorb electricity (charging mode) during low net-load demand periods and produce back to the grid (discharging mode) during high net-load demand periods to provide flexibility).

### Fuel prices

A single (1) scenario has been formulated regarding the evolution of the natural gas (NG) supply price (in €/MWh HHV) for all gas-fired units of the Greek interconnected power system. The price of the Dutch TTF future from the ICE Stock Exchange (data collection on 16 October 2023) has been used for the formulation of the gas supply price for the period January 2025-December 2025 [[1]](#footnote-1) . It is noted that an additional NG premium equal to 1 €/MWh\_th has been considered to formulate the final supply price for the relevant gas-fired generating units for the entire 2025. Table 2‑3 presents the monthly fuel supply price forecasts that have been used in this study.

**Table 2‑3. Monthly fuel prices forecasts for the year 2025**

| **Year** | **Month** | **Dutch TTF price forecast****[€/MWh HHV]** | **NG premium****[€/MWh HHV]** | **Final gas supply price****[€/MWh HHV]** |
| --- | --- | --- | --- | --- |
| 2025 | January | 56.67 | 1.0 | **57.67** |
| 2025 | February | 55.69 | 1.0 | **56.69** |
| 2025 | March | 53.97 | 1.0 | **54.97** |
| 2025 | April | 45.26 | 1.0 | **46.26** |
| 2025 | May | 43.16 | 1.0 | **44.16** |
| 2025 | June | 42.49 | 1.0 | **43.49** |
| 2025 | July | 42.55 | 1.0 | **43.55** |
| 2025 | August | 43.00 | 1.0 | **44.00** |
| 2025 | September | 43.24 | 1.0 | **44.24** |
| 2025 | October | 43.29 | 1.0 | **44.29** |
| 2025 | November | 44.57 | 1.0 | **45.57** |
| 2025 | December | 45.57 | 1.0 | **46.57** |

### CO2 emissions price

Carbon cost is another vital component in the formulation of the thermal generating units’ variable costs and further significantly affects the wholesale electricity market outcome. In this context, the mid-term evolution of CO2 (ETS) prices has been estimated for the year 2025 on the basis of the available EEX EUA futures price (data collection on 16 October 2023 [[2]](#footnote-2)). The annual ETS price considered in this study is equal to 92.37 €/tn for the entire year 2025.

### Cross-border interconnections

The precise calculation of the electricity flows on the cross-border interconnections of Greece with all neighbouring countries on an hourly basis would require the analytical simulation of the entire European power system and integrated European electricity market. Acknowledging the inherent difficulty of implementing this complex solution efficiently in a mid-term framework, for the scope of this study, a realistic alternative approach has been adopted, where detailed multi-step priced import offers and multi-step priced export bids have been formulated for all cross-border interconnections for the entire year 2025 in order to capture the inherent price dynamics between the interconnected countries and, thus, estimate the respective importing/exporting power flows to/from Greece. In this study, we also take into account the new (second) Extra High-Voltage (400 kV) interconnection line that has recently entered commercial operation allowing for increased electricity flows (up to 1100 MW/h) in the Greek-Bulgarian borders in both directions.

Regarding offer quantities, we use average historical cross-border hourly energy flow profiles for each interconnection (and each direction), which are differentiated in terms of type of the day (Monday to Sunday) and month of the year, also taking into account maintenance periods of the interconnection lines.

Regarding offer prices, appropriate offer/bid prices have been formulated for all cross-border interconnections aligned with the commodities (natural gas and CO2) price scenario used in this study.

Especially for the coupled interconnections (GR-IT, GR-BG) special attention has been paid in order to formulate multi-step import offers and export bid curves that are not overlapped, in order to simulate as close as possible the actual operation of the respective interconnection lines (implicit allocation of Physical Transmission Rights).

## Scenarios Formulation

In order to investigate the effect that the introduction of BESS would have on the operation of the Greek wholesale electricity market and the total wholesale market cost undertaken by the electricity Retailers and, subsequently, the end-consumers for the year 2025, two (2) scenarios were formulated and simulated, which are differentiated solely in terms of the installed capacity of BESS that will be operational in the Greek interconnected power system in 2025: In Scenario 1, no BESS are considered to operate in the Greek power system (zero BESS capacity), whereas in Scenario 2, 1000 MW/2000 MWh of BESS are considered to be fully operational during the entire year. The scenarios matrix is presented in Table 2‑4.

**Table 2‑4. Scenarios matrix**

| **Scenario** | **BESS** **Capacity**  | **System****Load** | **RES penetration** | **Gas****prices** | **CO2****prices** |
| --- | --- | --- | --- | --- | --- |
| **Scen. 1** | Zero | Base | Base | Base | Base |
| **Scen. 2** | 1000 MW / 2000 MWh |

# Simulation Results

## Day-ahead market results

The average monthly DAM clearing prices for both simulation scenarios are presented in tabular form in Table 3‑1 and are graphically illustrated in Figure 3‑1.

**Table 3‑1. Average monthly DAM clearing prices**

| **Month** | **Average monthly DAM clearing prices [€/MWh]** | *Difference [%]* |
| --- | --- | --- |
| **Scen. 1** | **Scen. 2** |
| January | 154.0 | 154.4 | **0.3%** |
| February | 146.5 | 146.5 | **0.0%** |
| March | 136.1 | 136.7 | **0.4%** |
| April | 122.5 | 123.4 | **0.7%** |
| May | 120.0 | 120.3 | **0.2%** |
| June | 121.5 | 121.5 | **0.0%** |
| July | 121.9 | 122.2 | **0.2%** |
| August | 119.9 | 120.3 | **0.4%** |
| September | 124.7 | 125.1 | **0.3%** |
| October | 121.3 | 121.3 | **0.0%** |
| November | 129.6 | 129.9 | **0.2%** |
| December | 128.9 | 128.9 | **0.0%** |
| **Average** | **128.8** | **129.1** | **0.2%** |



***Figure 3‑1.*** *Average monthly DAM clearing prices*

Simulation results show that among other factors (including system load demand and RES generation), the average monthly DAM clearing prices are highly dependent on the fuel prices, which directly define the thermal generating units’ variable cost during the entire study period. In this context, it is observed that during the first three-month period of the study (January-March 2025) where higher gas prices have been considered (see Table 2‑3), the resulting average monthly DAM clearing prices are significantly higher than during the remaining months of the year.

The negative effect that RES (especially PV) generation already has on the resulting daily profile of the DAM prices is illustrated in Figure 3‑2. It is clearly shown that the very large amounts of PV generation that are going to be injected gradually in the Greek wholesale market until 2025, will amplify the well-known “PV duck-effect” (which is already present in the Greek wholesale market, especially during low net system load demand months, e.g. April, May, October), causing severe RES overgeneration conditions mostly during the noon and early afternoon hours which, in turn, will lead to significantly lower DAM clearing prices during this period of the day. However, simulation results also indicate that the introduction of BESS is expected to partially counterbalance the PV duck-effect and lead to higher DAM clearing prices during early morning (hours 3-5) and, especially, during noon hours (hours 12-15), when BESS will normally charge. On the contrary, lower prices are expected mainly during the evening peak load hours (hours 18-21), when BESS will normally discharge. The net result would be a slight increase of the average monthly/annual DAM clearing prices (see Table 3‑1), which, however, would be accompanied by decreasing RES curtailments, as shown by the comparison of Table 5‑2 and Table 5‑3 in Annex.



***Figure 3‑2.*** *Effect of BESS on DAM clearing prices*

As already described in the Introduction, the total wholesale market cost for electricity Retailers comprises the DAM electricity procurement cost (which is directly affected by the average monthly/annual values as well as the daily profile of the DAM clearing prices over the year) and the additional Uplift Account Charges (UAs). Figure 3‑3 illustrates the breakdown of the annual Retailers’ wholesale market cost into the individual components, namely DAM procurement cost, UA-1 cost, UA-2 cost and UA-3 cost. It is clearly shown that the slight increase of DAM clearing prices that would be caused by the introduction of BESS in the Greek wholesale electricity market would unavoidably lead to a slight annual increase in the DAM procurement cost (~ +15.3 million €/y). Similarly, UA-1 cost that is directly dependent on the DAM clearing prices is also expected to present a marginal increase (~ +0.4 million €/y). However, UA-2 and UA-3 are expected to be notably reduced, since BESS will be eligible to provide valuable balancing services to the power system and, therefore, they are expected to increase competition in the provision of balancing capacity (equivalently, contribution to system reserves), which directly defines the UA-2 cost, as well as in the provision of upward/downward balancing energy in real-time, which directly defines the UA-3 cost. In quantitative terms, the introduction and operation of BESS is expected to reduce UA-2 by ~26.7 million €/y and UA-3 by ~66.0 million €/y.

Therefore, the estimated net wholesale market cost savings for electricity Retailers for 2025 will be equal to ~77.1 million € (or equivalently, ~1.44 €/MWh), which is analyzed to the aforementioned components as shown in Figure 3‑4. The analytical simulation and calculation results regarding the Retailers’ wholesale market cost on a monthly basis for both simulation scenarios are shown in Table 3‑2 and Table 3‑3.



***Figure 3‑3.*** *Annual Retailers’ wholesale market cost for 2025*



***Figure 3‑4.*** *Annual Retailers’ wholesale market cost savings due to BESS for 2025*

**Table 3‑2. Monthly Retailers’ wholesale market cost for 2025 (in €)**

| **Month** | **DAM Cost** **(million €)** | **UA-1 Cost** **(million €)** | **UA-2 Cost** **(million €)** | **UA-3 Cost** **(million €)** | **TOTAL Cost****(million €)** |
| --- | --- | --- | --- | --- | --- |
| **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | ***Diff.*** |
| January | 780.7 | 781.0 | 18.6 | 18.6 | 10.0 | 8.0 | 29.2 | 32.9 | **838.4** | **840.5** | ***2.1*** |
| February | 639.2 | 638.2 | 15.3 | 15.2 | 8.1 | 6.8 | 28.7 | 23.7 | **691.3** | **683.9** | ***-7.4*** |
| March | 588.9 | 591.0 | 14.2 | 14.3 | 9.1 | 6.2 | 47.9 | 30.7 | **660.1** | **642.2** | ***-18.0*** |
| April | 466.3 | 469.7 | 11.4 | 11.5 | 9.0 | 6.5 | 30.0 | 19.2 | **516.7** | **506.9** | ***-9.8*** |
| May | 492.9 | 494.9 | 12.0 | 12.0 | 8.6 | 6.5 | 32.9 | 24.3 | **546.4** | **537.7** | ***-8.8*** |
| June | 530.4 | 530.8 | 12.8 | 12.8 | 9.2 | 7.1 | 28.7 | 24.0 | **581.0** | **574.7** | ***-6.3*** |
| July | 638.4 | 640.5 | 15.1 | 15.2 | 9.3 | 7.3 | 29.4 | 25.7 | **692.2** | **688.7** | ***-3.5*** |
| August | 580.9 | 584.2 | 13.9 | 13.9 | 9.0 | 6.8 | 31.2 | 26.6 | **635.0** | **631.6** | ***-3.4*** |
| September | 535.3 | 537.6 | 12.9 | 13.0 | 9.1 | 6.8 | 20.4 | 14.5 | **577.7** | **571.9** | ***-5.8*** |
| October | 488.3 | 488.7 | 11.9 | 11.9 | 9.4 | 7.0 | 29.0 | 22.7 | **538.6** | **530.4** | ***-8.2*** |
| November | 560.8 | 561.6 | 13.5 | 13.5 | 9.4 | 7.1 | 26.9 | 26.1 | **610.6** | **608.2** | ***-2.4*** |
| December | 658.1 | 657.2 | 15.6 | 15.6 | 9.6 | 7.0 | 21.8 | 19.7 | **705.2** | **699.5** | ***-5.7*** |
| **TOTAL** | **6960.2** | **6975.5** | **167.2** | **167.5** | **109.9** | **83.1** | **356.1** | **290.1** | **7593.3** | **7516.2** | ***-77.1*** |

**Table 3‑3. Monthly Retailers’ wholesale market cost for 2025 (in €/MWh)**

| **Month** | **DAM Cost** **(€/MWh)** | **UA-1 Cost** **(€/MWh)** | **UA-2 Cost** **(€/MWh)** | **UA-3 Cost** **(€/MWh)** | **TOTAL Cost****(€/MWh)** |
| --- | --- | --- | --- | --- | --- |
| **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | **Scen.1** | **Scen.2** | ***Diff.*** |
| January | 156.52 | 156.58 | 3.72 | 3.72 | 2.00 | 1.61 | 5.85 | 6.59 | **168.09** | **168.51** | ***0.42*** |
| February | 148.68 | 148.44 | 3.55 | 3.55 | 1.89 | 1.57 | 6.67 | 5.50 | **160.79** | **159.06** | ***-1.73*** |
| March | 136.97 | 137.46 | 3.31 | 3.32 | 2.11 | 1.45 | 11.15 | 7.13 | **153.55** | **149.36** | ***-4.18*** |
| April | 122.35 | 123.25 | 2.99 | 3.01 | 2.37 | 1.70 | 7.88 | 5.04 | **135.59** | **133.01** | ***-2.58*** |
| May | 118.93 | 119.41 | 2.89 | 2.90 | 2.07 | 1.56 | 7.95 | 5.86 | **131.84** | **129.73** | ***-2.11*** |
| June | 120.88 | 120.99 | 2.91 | 2.91 | 2.09 | 1.62 | 6.55 | 5.47 | **132.42** | **130.99** | ***-1.43*** |
| July | 121.40 | 121.80 | 2.88 | 2.89 | 1.77 | 1.38 | 5.58 | 4.89 | **131.63** | **130.95** | ***-0.67*** |
| August | 119.11 | 119.79 | 2.84 | 2.86 | 1.85 | 1.40 | 6.39 | 5.46 | **130.20** | **129.51** | ***-0.69*** |
| September | 124.24 | 124.77 | 2.99 | 3.01 | 2.11 | 1.59 | 4.74 | 3.37 | **134.08** | **132.74** | ***-1.34*** |
| October | 121.63 | 121.74 | 2.97 | 2.97 | 2.35 | 1.76 | 7.22 | 5.66 | **134.17** | **132.13** | ***-2.05*** |
| November | 130.85 | 131.03 | 3.15 | 3.16 | 2.20 | 1.65 | 6.28 | 6.08 | **142.47** | **141.92** | ***-0.55*** |
| December | 130.72 | 130.53 | 3.11 | 3.10 | 1.91 | 1.39 | 4.33 | 3.92 | **140.06** | **138.94** | ***-1.12*** |
| **TOTAL** | **129.59** | **129.87** | **3.11** | **3.12** | **2.05** | **1.55** | **6.63** | **5.40** | **141.38** | **139.94** | ***-1.44*** |

It is therefore concluded that the added value brought by the introduction and operation of 1000MW BESS with 2-h energy capacity during the year 2025 would be noteworthy, since it would lead to annual cost savings for the electricity Retailers, and subsequently, for the end-consumers, that are equal to ~**77.1 million €.**

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# Annex – Technical and Modeling Aspects

In the following paragraphs, (a) the analytical timeline for the construction/withdrawal of thermal generating units, (b) the detailed unit techno-economic data that are used as input data in the simulation models, (c) the formulation of the thermal generating units’ heat rate and cost functions, (d) the bidding strategy assumed for all entities participating in the new electricity market, and e) analytical input data used in the market simulations, are presented.

## Construction/withdrawal of conventional generating units

Table 5‑1 presents the analytical timeline for the construction/withdrawal of conventional (thermal and hydro) generating units that was considered in this study.

**Table 5‑1. Timeline for the construction/ withdrawal of conventional generating units**

| **Unit Name** | **Fuel** | **Net Capacity****[MW]** | **Commercial Operation** **Date** | **Unit Name** | **Fuel** | **Net Capacity****[MW]** | **Withdrawal Date** |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Ptolemaida 5 | Lignite | 615 | 01/12/2023 | Ag. Dimitrios 1 | Lignite | 274 | 30/06/2025 |
| New CCGT Mytilineos | NG | 806 | 01/12/2023 | Ag. Dimitrios 2 | Lignite | 274 | 30/06/2025 |
| New CCGT TERNA-MORE | NG | 858 | 01/09/2024 |  |  |  |  |
| Kardia\_CHP | NG | 105 | 01/10/2024 |  |  |  |  |
| Metsovitiko | Hydro | 29 | 01/01/2025 |  |  |  |  |
| **Sum** |  | **2,413** |  | **Sum** |  | **548** |  |

## Unit data and cost functions

### Unit techno-economic data

The unit techno-economic data used for the solution of the mid-term scheduling of the Greek electricity market are acquired from publicly available sources, and comprise the following:

1) the unit technical maximum, , in MW

2) the unit technical minimum, , in MW

3) the minimum up time, in hours

4) the minimum down time, in hours

5) the ramp-up rate, in MW/min

6) the ramp-down rate, in MW/min

7) the maximum output under Automatic Generation Control (AGC), in MW

8) the minimum output under Automatic Generation Control (AGC), in MW

9) the ramp rate under AGC (both upwards and downwards), in MW/min

10) the secondary reserve range, in MW

11) the maximum capability to provide primary reserve, in MW

12) the maximum capability to provide tertiary spinning reserve, in MW

13) the maximum capability to provide tertiary non-spinning reserve, in MW

14) the fuel type of the unit

15) the start-up cost, in €/start-up

16) the shut-down cost, in €/shut-down

17) the fuel cost in standby mode, in order to be ready to provide tertiary spinning reserve, in €/MWh

18) the maintenance and operation cost in standby mode, in order to be ready to provide tertiary non-spinning reserve, in €/MWh

In case of thermal units, in addition to the above the following techno-economic data have been considered:

1) special cost for raw materials (except from fuel), in €/MWh

2) special cost for maintenance and operation (O&M) above the fixed maintenance costs, in €/MWh

3) special cost for additional human resources (except from the fixed human resources cost), in €/MWh

4) special cost for fuel improvement materials, in €/MWh

5) the unit emission rate (for CO2), in T/MWh

6) the unit heat rate function for the ten output levels between technical minimum and technical maximum.

Figure 5‑1 presents a typical heat rate function of a thermal unit.



***Figure 5‑1.*** *Typical heat rate function of a thermal unit*

### Thermal units’ variable cost

The variable cost of a thermal unit *thr* is computed as follows:

 [€/MWh] (5.1)

where

 the points of the heat rate function of the thermal unit *thr*, in ten output levels from the technical minimum to the technical maximum, in GJ/MWh

 the fuel cost*[[3]](#footnote-3)* *f* used by the thermal unit *thr*, in €/Ton or €/103 lt or €/Norm m3; without loss of accuracy, it is supposed here that each thermal unit uses one fuel (primary fuel)

 the lower heating value (LHV) of fuel *f* used by the thermal unit *thr*, in GJ/tn or GJ/103 lt or GJ/Nm3

The fuel cost and the lower heating value are determined on a monthly basis, while the points of the heat rate function are determined as fixed values throughout the optimization horizon. The unit *u* variable cost is computed at the unit metering point (hereinafter “meter point”) as follows:

 [€/MWh] (5.2)

where

 the special cost for raw material (except from the primary fuel) of the thermal unit *thr*, in €/MWh

 the cost for maintenance and operation (O&M) above the fixed maintenance costs of the thermal unit *thr*, in €/MWh

 special cost for additional human resources (except from the fixed human resources cost) of the thermal unit *thr*, in €/MWh

 special cost for fuel improvement materials of the thermal unit *thr*, in €/MWh

 the special emission cost (CO2) of the thermal unit *thr*, in €/MWh

The special emission cost (CO2) of the thermal unit *thr*, , is computed as follows:

 [€/MWh] (5.3)

where

 the CO2 emissions rate for each produced MWh by the thermal unit *thr*, in tn/MWh; this value is fixed for each thermal unit

 the CO2 emissions price, in €/tn

The unit variable cost has the same form with the heat rate function shown in Figure 5‑1. The minimum value of the ten points of the variable cost curve is defined as the **Minimum Variable Cost** of the thermal unit *thr*, , This value is used here for the initialization of the priced energy offers of the thermal units, as described in more details in par. 5.3.

### Thermal units’ hourly cost

The hourly cost of a thermal unit *thr* at the “meter point” is computed as follows:

 [€/h] (5.4)

In Figure 5‑2 a typical hourly cost curve of a thermal unit is presented.



***Figure 5‑2.*** *Typical hourly cost curve of a thermal unit*

## Formulation of unit energy and reserve offers

### Day Ahead Market (DAM)

In principle, the energy offers of the conventional (thermal and hydro) production units in the DAM are created based on their Minimum Variable Cost (MVC), with the following main assumptions:

1. PPC submits block offers with quantity equal to the unit’s technical minimum and price at most equal to the MVC, for the lignite units and all available PPC gas-fired units. This way, PPC safeguards a minimum share of competitive annual gas-fired generation to serve its own retail load, thus mitigating electricity procurement from third parties. In this context, given that PPC will probably continue to operate as a net buyer in the wholesale market for the entire study period, for the remaining capacity of all gas-fired units, PPC is considered to submit multi-step hybrid offers mainly priced at the MVC of each unit in order to drive market clearing prices downwards as much as possible and, thus, minimize the cost of purchasing energy from third parties (IPPs and imports. A small price mark-up (e.g. 2-10 €/MWh) is applied in the last price-quantity pairs for some inflexible units (e.g. Megalopoli 5, Lavrio 4, Komotini).
2. The existing IPP gas-fired generating units (Heron\_CC, Protergia\_CC, Korinthos Power, Elpedison Thess and Elpedison Thisvi) as well as the three new IPP CCGT units (i.e. New CCGT MYT, New CCGT TERNA-MORE, New CCGT Alexandroupolis) are considered to submit hybrid offers with multiple blocks, where their technical minimum is offered at their own MVC and their remaining capacity is offered with a notable price mark-up (e.g. 5-25 €/MWh), aiming at increasing the resulting SMP during scarcity periods, following current practice in the DAM.
3. In all scenarios, the Market Operator submits on behalf of units “ALOUMINIO” and “Kardia\_CHP” a price-taking energy offer for the first 127.9 MWh and 90 MWh, respectively, (accounting for the operation of the high-efficiency co-generation gas-fired unit), and the remaining capacity is assumed to be submitted by the associated Producers at the respective units’ variable cost.
4. The hydro units' energy offers are formulated slightly above the higher available thermal unit’s offer, in order to minimize the additional injections from hydro units (above the mandatory injections).
5. The bidding strategies for energy injection and withdrawal of PSPs and BESS were formulated according to the X% rule, according to which electricity consumption (for pumping operation or BESS charging) takes place when the DAM clearing price does not exceed the X% of the market clearing price of those hours that the corresponding electricity injection takes place (where X% stands for the round-trip efficiency of the PSPs pumping/injection cycle and BESS charging/discharging cycle, e.g. 70% or 88%, respectively) and which fully ensures the efficient utilization of PSPs and BESS in the DAM framework. Under this rule, the offer price for energy absorption is selected to be lower than the offer price of the cheapest thermal unit that is available and the offer price for the corresponding energy injection is formed at significantly higher levels under the X% rule, as discussed above. Obviously, this bidding strategy renders BESS entities much more competitive than the PSPs, given their significantly higher round-trip efficiency.

### Integrated Scheduling Process (ISP) and Real-Time Balancing Energy Market (RTBEM)

According to the strategic behavior of PPC and IPPs already observed in the current real-time balancing market (ISP solutions made publicly available by ADMIE), in this study the balancing energy offers have been formulated according to the following main assumptions:

1. Regarding PPC lignite and gas-fired units, these are supposed to submit upward balancing energy offers higher than their MVC but lower than the respective estimated offers of IPP units in order to be more competitive against IPP units and increase production and profits in the RTBEM. On the contrary, they are considered to submit downward balancing energy offers significantly lower than their MVC (especially regarding lignite units) in order to follow a commitment schedule that will be as close as possible to their validated market schedule.
2. Regarding IPPs’ gas-fired units, these are supposed to submit high upward balancing energy offers, especially during peak months (January, February, June, July, November, December), to take advantage of possible high positive system imbalances that may occur during the real-time operation (e.g. due to forced outages of lignite units or unexpected increase of net system load) and, subsequently increase production and profits. On the contrary, they are considered to submit downward balancing energy offers lower than PPC’s respective offers.
3. Regarding hydro units, a similar strategy with that followed in the DAM (i.e. upward balancing energy offer slightly above the higher thermal unit’s respective offer and downward balancing energy offer slightly below the lowest thermal unit’s respective offer) has been considered, so that the deviations of hydro production in real-time as compared to the respective DAM cleared quantities are minimized.
4. Regarding the bidding strategies for the provision of upward and downward balancing energy of the PSPs and the BESS, these have been formulated as follows: The offer price for the provision of upward (downward) balancing energy of each PSP or BESS in pumping mode is marginally higher (lower) than the respective offer price for energy withdrawal in the DAM and the offer price for the provision of upward (downward) balancing energy of each PSP or BESS in generation mode is also marginally higher (lower) than the respective offer price for energy injection in the DAM, so that the rule of X% is always valid.
5. Regarding balancing reserve offers for Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR), it is expected that the increased competition among eligible generating and demand entities (especially after the introduction of the new PSPs and the increasing BESS capacities) will drive current reserve clearing prices significantly lower than the current levels. In this context, the reserve offer prices have been formulated in the range 4-12 €/MW for the various reserve products, where BESS are considered to be the most competitive entities (i.e they submit slightly lower offer prices than any other entity for all reserve products), followed by hydro plants and PSPs and followed, at last, by the thermal generating units.

## Analytical Simulation Results

Table 5‑2 and Table 5‑3 present the analytical monthly energy generation mix of the Greek interconnected power system for simulation scenarios Scen.1 and Scen.2, respectively.

**Table 5‑2. Greek interconnected power system energy generation mix – Scenario 1**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Entity / Month** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **TOTAL** |
| **Lignite Units [MWhe]** | **633,946** | **469,987** | **219,333** | **219,189** | **97,872** | **230,248** | **261,597** | **176,184** | **29,740** | **219,197** | **183,006** | **281,699** | **3,021,999** |
| *Gas Units (PPC) [MWhe]* | *609,116* | *262,326* | *168,497* | *229,317* | *158,817* | *165,960* | *256,270* | *215,085* | *357,825* | *194,997* | *430,814* | *378,827* | *3,427,851* |
| *Gas Units (IPPs) [MWhe]* | *1,732,598* | *1,138,335* | *797,736* | *744,108* | *778,370* | *1,014,190* | *1,242,118* | *915,269* | *1,345,339* | *965,529* | *1,487,045* | *1,329,746* | *13,490,383* |
| **Gas Units [MWhe]** | **2,341,714** | **1,400,661** | **966,234** | **973,424** | **937,187** | **1,180,150** | **1,498,388** | **1,130,355** | **1,703,164** | **1,160,526** | **1,917,859** | **1,708,573** | **16,918,234** |
| **Diesel / Oil Units (Non-Interc. Islands) [MWhe]** | **120** | **50** | **0** | **0** | **321** | **380** | **50** | **363** | **200** | **0** | **368** | **0** | **1,851** |
| **Large Hydros [MWhe]** | **403,378** | **313,777** | **335,511** | **366,573** | **388,149** | **476,191** | **600,365** | **516,123** | **327,899** | **380,104** | **398,124** | **468,221** | **4,974,415** |
| *Imports [MWhe]* | *329,077* | *468,724* | *784,636* | *642,007* | *667,286* | *854,822* | *688,130* | *549,464* | *595,647* | *555,008* | *498,362* | *650,700* | *7,283,863* |
| *Exports [MWhe]* | *335,719* | *183,202* | *195,111* | *278,146* | *177,779* | *73,867* | *197,093* | *352,915* | *236,307* | *328,951* | *191,823* | *191,609* | *2,742,522* |
| **Net Imports [MWhe]** | **-6,642** | **285,522** | **589,525** | **363,860** | **489,507** | **780,956** | **491,037** | **196,549** | **359,339** | **226,057** | **306,539** | **459,091** | **4,541,340** |
| **RES / Small Cogen [MWhe]** | **1,762,711** | **2,019,979** | **2,406,863** | **2,155,002** | **2,440,859** | **1,980,246** | **2,703,133** | **3,144,417** | **2,128,934** | **2,247,184** | **1,655,709** | **2,418,535** | **27,063,572** |
| *RES Curtailments [MWhe]* | *436* | *4,933* | *58,631* | *50,615* | *96,752* | *40,861* | *41,726* | *48,152* | *25,478* | *36,412* | *24,867* | *12,408* | *441,271* |
| **BESS Discharge [MWhe]** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Total Injection [MWhe]** | **5,135,227** | **4,489,975** | **4,517,465** | **4,078,049** | **4,353,896** | **4,648,170** | **5,554,571** | **5,163,990** | **4,549,276** | **4,233,068** | **4,461,605** | **5,336,120** | **56,521,412** |
| *Pumping (PPC) [MWhe]* | *69,068* | *80,819* | *143,585* | *139,131* | *148,207* | *126,540* | *132,195* | *142,939* | *109,509* | *135,407* | *109,983* | *111,295* | *1,448,676* |
| *Pumping (IPPs) [MWhe]* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* |
| **Total Pumping [MWhe]** | **69,068** | **80,819** | **143,585** | **139,131** | **148,207** | **126,540** | **132,195** | **142,939** | **109,509** | **135,407** | **109,983** | **111,295** | **1,448,676** |
| **BESS Charge [MWhe]** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **System Load (with system losses) [MWhe]** | **5,066,159** | **4,407,888** | **4,373,880** | **3,938,917** | **4,190,379** | **4,521,630** | **5,422,376** | **5,021,051** | **4,439,767** | **4,097,661** | **4,351,623** | **5,228,385** | **55,059,717** |
| Interconnection Flexibility [MWhe] | 0 | 1,269 | 0 | 0 | 15,310 | 0 | 0 | 0 | 0 | 0 | 0 | -3,560 | 13,019 |

**Table 5‑3. Greek interconnected power system energy generation mix – Scenario 2**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Entity / Month** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **TOTAL** |
| **Lignite Units [MWhe]** | **660,742** | **498,405** | **258,242** | **250,005** | **103,769** | **259,637** | **286,813** | **211,289** | **40,356** | **258,438** | **199,264** | **309,746** | **3,336,705** |
| *Gas Units (PPC) [MWhe]* | *607,482* | *245,524* | *133,450* | *187,657* | *109,672* | *154,450* | *229,195* | *192,577* | *353,967* | *186,931* | *456,955* | *357,087* | *3,214,948* |
| *Gas Units (IPPs) [MWhe]* | *1,695,909* | *1,125,875* | *734,870* | *689,612* | *762,780* | *983,972* | *1,217,049* | *888,170* | *1,307,887* | *939,292* | *1,443,540* | *1,311,803* | *13,100,758* |
| **Gas Units [MWhe]** | **2,303,391** | **1,371,399** | **868,320** | **877,269** | **872,452** | **1,138,422** | **1,446,244** | **1,080,747** | **1,661,854** | **1,126,222** | **1,900,495** | **1,668,890** | **16,315,706** |
| **Diesel / Oil Units (Non-Interc. Islands) [MWhe]** | **0** | **0** | **0** | **0** | **50** | **0** | **0** | **0** | **0** | **50** | **0** | **0** | **100** |
| **Large Hydros [MWhe]** | **408,558** | **303,340** | **322,629** | **354,699** | **384,682** | **472,651** | **594,318** | **519,704** | **314,605** | **361,770** | **382,620** | **454,879** | **4,874,456** |
| *Imports [MWhe]* | *342,690* | *469,336* | *774,469* | *639,878* | *653,410* | *847,623* | *690,787* | *531,285* | *585,568* | *531,556* | *494,764* | *647,612* | *7,208,977* |
| *Exports [MWhe]* | *325,646* | *177,450* | *169,424* | *239,830* | *156,723* | *53,962* | *172,990* | *328,017* | *205,857* | *319,237* | *179,135* | *176,968* | *2,505,240* |
| **Net Imports [MWhe]** | **17,045** | **291,886** | **605,045** | **400,048** | **496,687** | **793,660** | **517,797** | **203,268** | **379,711** | **212,320** | **315,629** | **470,644** | **4,703,738** |
| **RES / Small Cogen [MWhe]** | **1,761,858** | **2,020,865** | **2,443,377** | **2,182,320** | **2,471,065** | **1,987,440** | **2,711,080** | **3,149,183** | **2,144,420** | **2,258,011** | **1,655,004** | **2,421,631** | **27,206,253** |
| *RES Curtailments [MWhe]* | *1,289* | *4,047* | *22,117* | *23,297* | *66,546* | *33,667* | *33,779* | *43,386* | *9,992* | *25,585* | *25,572* | *9,312* | *298,590* |
| **BESS Discharge [MWhe]** | **53,540** | **49,280** | **54,560** | **52,540** | **54,560** | **52,800** | **54,560** | **54,300** | **52,800** | **54,560** | **52,800** | **54,489** | **640,789** |
| **Total Injection [MWhe]** | **5,205,134** | **4,535,174** | **4,552,173** | **4,116,881** | **4,383,266** | **4,704,610** | **5,610,812** | **5,218,491** | **4,593,746** | **4,271,371** | **4,505,812** | **5,380,278** | **57,077,747** |
| *Pumping (PPC) [MWhe]* | *78,134* | *71,286* | *116,308* | *118,259* | *130,915* | *122,980* | *126,436* | *135,735* | *93,979* | *111,710* | *94,189* | *93,534* | *1,293,464* |
| *Pumping (IPPs) [MWhe]* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* | *0* |
| **Total Pumping [MWhe]** | **78,134** | **71,286** | **116,308** | **118,259** | **130,915** | **122,980** | **126,436** | **135,735** | **93,979** | **111,710** | **94,189** | **93,534** | **1,293,464** |
| **BESS Charge [MWhe]** | **60,841** | **56,000** | **62,000** | **59,705** | **62,000** | **60,000** | **62,000** | **61,705** | **60,000** | **62,000** | **60,000** | **61,919** | **728,169** |
| **System Load (with system losses) [MWhe]** | **5,066,159** | **4,407,888** | **4,373,880** | **3,938,917** | **4,190,379** | **4,521,630** | **5,422,376** | **5,021,051** | **4,439,767** | **4,097,661** | **4,351,623** | **5,228,385** | **55,059,717** |
| Interconnection Flexibility [MWhe] | **0** | **0** | **-15** | **0** | **-28** | **0** | **0** | **0** | **0** | **0** | **0** | **-3,560** | **-3,603** |

1. <https://www.theice.com/products/27996665/Dutch-TTF-Gas-Futures/data?marketId=5132977> [↑](#footnote-ref-1)
2. <https://www.eex.com/en/market-data/environmentals/futures> [↑](#footnote-ref-2)
3. It is assumed that each thermal unit uses only one fuel. [↑](#footnote-ref-3)