Executive Summary

ECCO International ("ECCO") was awarded a contract by Hellenic Energy Exchange (HEnEx) to investigate the demand-side market power that could be potentially exercised by Public Power Corporation (PPC) by simulation scenarios using various actual and forecasted operational and other market data from the Greek wholesale electricity market. The key Market Power Index which is studied and analyzed is the maximum threshold of the Forward Hedge Ratio (FHR) to be imposed on large suppliers (currently PPC only, following recent RAE Decision 1014/2021), following the provisions of the Day-Ahead Market and Intra-Day Market Trading Rulebook of the Greek wholesale electricity market, that will not substantially reduce the DAM liquidity resulting in lack of price discovery. Other buyer-side market power indices were also calculated.

In this report we present the assumptions deployed in the study as approved by HEnEx, the basic methodology we have followed in order to determine key market power indices to analyze the potential for market power abuse by PPC, the simulation results and a recommendation regarding the maximum FHR Index.

The study was based on detailed hourly simulation results for the study period July 2022 - December 2025 using a specialized day-ahead market simulation software. ECCO performed the required analysis considering the evolution of the PPC retail market share over the said study period as well as 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, CO_2 prices, future lignite-fired and gas-fired units' availability, interconnection of islands with the Mainland power system, etc.

The assumptions of this study were mainly based on the commitments that are included in the National Plan for Energy and Climate (NECP) that was approved by the Greek State and the European Commission at the end of 2019, the assumptions of the new National Resource Adequacy Assessment of Greek IPTO (ADMIE) that were put in public consultation in July 2021, the assumptions of the latest Ten-Year Network Development Plan 2023-2032 of ADMIE that was recently submitted to the Regulatory Authority for Energy for approval (April 2022) and related updated information. According to these sources, major transformations are expected to take place in the Greek power system in the forthcoming period, including among others the commercial operation of the new lignite unit Ptolemaida 5 in January 2023, the withdrawal of most existing lignite-fired power plants by the end of 2023, the aggressively increasing RES generation, the full interconnection of Crete and West Cyclades complex by 2025, the construction and operation of new highly efficient and flexible gas-fired units, the gradual introduction of battery energy storage systems, the operation of new cross-border interconnection lines with neighboring countries, etc.

The main assumptions of this study for the period July 2022 – December 2025 include the following:

1. **Electricity load forecast:** A single (1) scenario regarding the total electricity consumption and the peak load forecast for the Greek interconnected power system for the period July 2022-December 2025 has been formulated, which is identical with the NECP Scenario of the Ten-Year Network Development Plan 2023-2032 that has been finalized by ADMIE and recently submitted to RAE for approval (April 2022).
2. **RES installed capacity:** A single (1) scenario has been formulated, where a particularly aggressive development plan regarding mainly PV and secondarily wind plants penetration has been considered from 2022 onwards as compared to the provisions of NECP 2019, leading to ~57% RES share in the final electricity consumption in 2025 (also including the electricity generation of large hydro plants). This scenario has been formulated on the basis that a notably high share of the pending applications for wind and mainly PV installations will be finally materialized. In this context, this scenario is fully aligned with the updated and more ambitious targets to be set in the revised NECP (currently under drafting) regarding RES installations, according to which RES share is expected to exceed 70% of the final electricity consumption in 2030.
3. **Hydro and pumped storage plants:** Besides the existing hydro system, one new large hydro plant is expected to enter commercial operation during the course of the study period, namely “Metsovitiko” (+29 MW) in January 2025. Regarding pumped-storage technology, apart from the two existing Pumped Storage Plants (PSP) owned by PPC, namely Sfikia (3 x 110 MW) and Thesavros (3 x 125 MW), no additional pumped-storage unit is expected to enter commercial operation in the Greek power system during the course of the study period.
4. **Energy Storage Systems:** New energy storage systems in the form of Battery Energy Storage Systems (BESS) are expected to be gradually incorporated into the Greek interconnected power from January 2024 onwards. In this study, a single (1) BESS penetration scenario has been considered, according to which the total installed capacity of BESS will steadily increase from January 2024 onwards and will reach 1.0 GW in December 2025. BESS are considered to have an overall round-trip efficiency of 88% and their daily operation in the day-ahead market was simulated similarly to the rationale adopted for the 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).

5. **Construction/withdrawal of power generating units:** The evolution of the conventional (thermal and hydro) generation capacity in monthly analysis during the study period is illustrated in Figure A. The analytical timeline for the construction / withdrawal of the conventional thermal generating units is presented in Annex A (see Table 1).

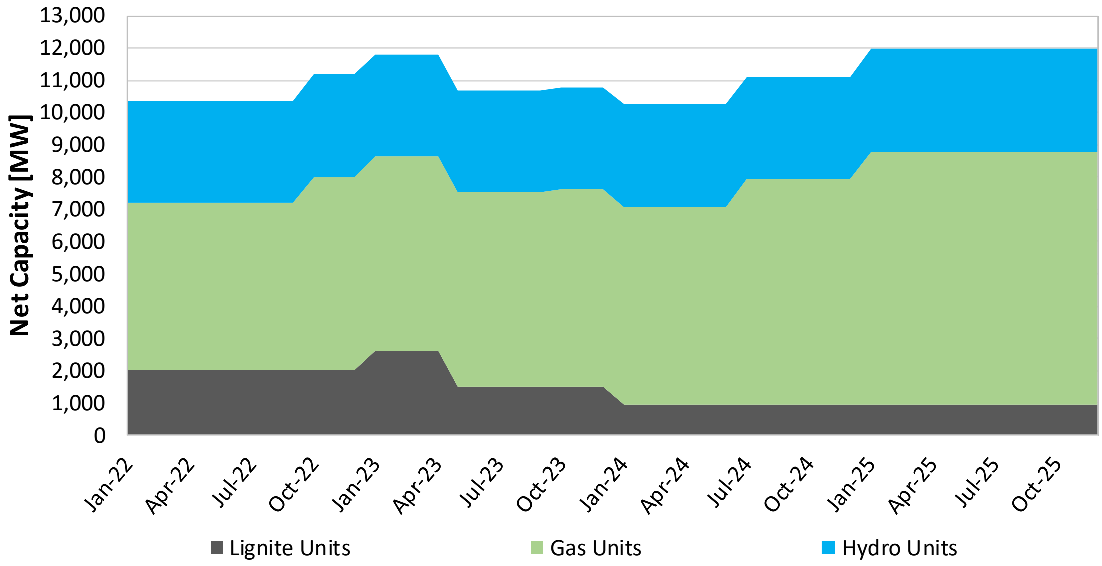

Figure A. Evolution of conventional generation capacity

6. **Fuel prices:** A single (1) scenario regarding the evolution of gas supply prices on the basis of oil (Brent) and Dutch TTF future price indicators (which jointly determine historically the average gas supply price in Greece). Specifically, the following core assumptions have been considered:

   i. The available monthly Brent futures prices from the ICE Stock Exchange (data collection on 03 June 2022) have been used for the period July 2022-December 2025, according to which the Brent price decreases steadily from ~120$/bbl in July 2022 to ~78.2 $/bbl in December 2025.

   ii. The available monthly Dutch TTF futures prices from the ICE Stock Exchange (data collection on 03 June 2022) have also been used for the period July 2022-December 2025, according to which the TTF price decreases from ~83.1 €/MWh in July 2022 to ~47.3 €/MWh in December 2025.

7. **Emissions (CO_2) prices:** A single (1) scenario regarding the evolution of CO_2 (ETS) prices has been formulated on the basis of the available EEX EUA futures prices (data collection on 03 June 2022). For those months that no futures prices were available, linear interpolation has been used. ETS

price increases from 86.53 €/tn CO_2 in July 2022 to 99.06 €/tn CO_2 in December 2025.

8. **Unit energy offers:** In principle, for the purposes of this study the energy offers (sell orders) of all market entities (thermal, hydro, PSPs, BESS) in the DAM are created on the basis of the Minimum Variable Cost (MVC) of the available thermal units., which is differentiated on a monthly basis, following the monthly variation of the respective fuel (gas) cost and the monthly variation of the respective CO_2 cost. Using thermal units' MVC as a starting point, realistic DAM offers for all market entities, namely thermal, hydro, PSPs and BESS units, and for the entire study period were formulated, also considering their recent past bidding behavior in the Greek day-ahead market. For this purpose, indicative DAM offer data for all current market participants and for the week 07-13/03/2022 have been provided by HEnEx to ECCO under a non-disclosure agreement to be used exclusively for the purposes of this study. These data were appropriately taken into account in the formulation of the analytical bidding strategy for all market entities.

9. **Cross-border interconnections:** Detailed multi-step priced import offers and multi-step priced export bids have been formulated for all cross-border interconnections for the entire study period July 2022-December 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. The new (second) Extra High-Voltage (400 kV) interconnection line that is being constructed between Greece and Bulgaria and is expected to enter commercial operation in January 2023 allowing for increased electricity flows in the Greek-Bulgarian borders in both directions has also been taken into account.

In the above framework, seven (7) scenarios were formulated and simulated, which are differentiated solely in terms of the maximum allowed FHR for PPC, which was assumed to be equal to 0%, 10%, 20%, 25%, 30%, 35% and 40%. In other words, it is considered that PPC is permitted to physically contract 0%,10%, 20%, …, 40% of its hourly represented load in the forward market. Afterwards, the respective amount of forward physical quantities were removed from the quantity part of PPC's thermal units' hourly offers.

According to Section 4.4.2.2 of the Day-Ahead Market and Intra-Day Market Trading Rulebook of HEnEx:

"1. Για κάθε Προμηθευτή με μερίδιο λιανικής αγοράς που υπερβαίνει ένα όριο Χ% και για κάθε Αγοραία Χρονική Μονάδα, το ποσοστό των ποσοτήτων ενέργειας που περιλαμβάνονται στις επικυρωμένες Δηλώσεις Προγραμμάτων Φυσικής Απόληψης και που αντιστοιχούν σε ποσότητες ενέργειας επί συναλλαγών Ενεργειακών Χρηματοπιστωτικών Μέσων εντός της Ενεργειακής Χρηματοπιστωτικής Αγοράς ή διμερώς, επί του συνόλου των ποσοτήτων ενέργειας που αγοράστηκαν με αποδεκτές

Εντολές Αγοράς στην Αγορά Επόμενης Ημέρας, δεν δύναται να ξεπερνά ένα όριο Α%. Οι τιμές Χ% και Α% ορίζονται σε ετήσια βάση με απόφαση της ΡΑΕ, κατόπιν εισήγησης του ΕΧΕ.

2. Σε περίπτωση παραβίασης του περιορισμού του Μέγιστου Ποσοστού Ενεργειακών Χρηματοπιστωτικών Μέσων με Φυσική Παράδοση από ένα Προμηθευτή p για Αγοραία Χρονική Μονάδα h της Ημέρας Εκπλήρωσης Φυσικής Παράδοσης D, με την κοινοποίηση των αποτελεσμάτων της Αγοράς Επόμενης Ημέρας το ΕΧΕ υπολογίζει για τον εν λόγω Προμηθευτή και για αυτή την Ημέρα Εκπλήρωσης Φυσικής Παράδοσης D Χρεώσεις Μη Συμμόρφωσης $NCC_{p,h}$, ως εξής:

$$NCC_{p,h} = \max\left(\left[\sum_{z} PON_{z,p,h} - A\% * \sum_{z}\left(Y_{z,p,h}\right)\right] * CAP, 0\right)$$

όπου:

$PON_{z,p,h}$: η Δήλωση Προγραμμάτων Φυσικής Απόληψης που υποβάλλεται στη Ζώνη Προσφορών z από τον Προμηθευτή p για μια Αγοραία Χρονική Μονάδα h της Ημέρας Εκπλήρωσης Φυσικής Παράδοσης D,

$Y_{z,p,h}$: οι αποδεκτές ποσότητες ενέργειας του Προμηθευτή p στην Αγορά Επόμενης Ημέρας για μία Αγοραία Χρονική Μονάδα h της Ημέρας Εκπλήρωσης Φυσικής Παράδοσης D,

Α%: το ισχύον μέγιστο όριο του ανωτέρω περιορισμού,

CAP: η Ανώτατη Τιμή Εντολής της Αγοράς Επόμενης Ημέρας.

3. Η χρέωση είναι αθροιστική για όλες τις Αγοραίες Χρονικές Μονάδες μιας Ημέρας Εκπλήρωσης Φυσικής Παράδοσης και κοινοποιείται από το ΕΧΕ στον Φορέα Εκκαθάρισης σε χρόνο και με διαδικασία που ορίζονται σε σχετική Τεχνική Απόφαση του ΕΧΕ.

4. Για τον υπολογισμό της ανωτέρω Χρέωσης Μη Συμμόρφωσης δεν λαμβάνονται υπόψη οι Εντολές Αγοράς με Αποδοχή Τιμής και Προτεραιότητα Εκτέλεσης που υποβάλλονται από το ΕΧΕ, σύμφωνα με την υποενότητα 4.1.3.2, εκ μέρους κάθε Προμηθευτή που εκπροσωπεί καταναλωτές στο Μικρό Συνδεδεμένο Σύστημα Κρήτης κατά τη διάρκεια λειτουργίας του Μικρού Συνδεδεμένου Συστήματος Κρήτης".

It is important to keep in mind that the dominant player will continue to be a net buyer in the DAM in the foreseeable future and as such, in principle, it will continue to implement strategies that result in as low day-ahead market clearing prices as possible in order to minimize the cost of purchasing energy from third parties (IPPs and imports) to serve its retail portfolio.

Based on our experience from the analysis of similar markets around the world, the ability of the dominant player to exercise buyer-side market power will depend upon its ability to withhold demand from the spot market while relying on enough of its generation to satisfy its load

requirements (e.g. through bilateral contracts) while keeping energy expenditures down. The key factor will be the cost of the generation of the dominant player relative to what would be considered competitive generation. If PPC generation has a higher cost than competitive generation, but not too high, then such a strategy is possible. If PPC generation is much more expensive than competitive generation, then it may be more difficult to successfully pull off this market strategy. This analysis brings to the fore the design options adopted for integrating forward positions in the Day-Ahead market. Specifically, if the PPC generation backing forward contracts is more expensive than the DAM price, it is preferable for PPC to buy energy from the market to support its bilateral contracts.

For each FHR scenario the DAM liquidity was calculated along with the hours where the liquidity drops to zero. Furthermore, the profile of the DAM prices for each scenario was analyzed.

The key conclusion is that the DAM liquidity is rapidly decreasing as the FHR Index is increasing from 0% to 40%. Specifically, already from Scenario 2 (FHR=10%) the DAM liquidity is less than 50% on average for the entire study period, whereas in Scenario 5 (FHR=30%) DAM liquidity drops below 40% on average for the entire study period. However, this observation is masking the fact that for certain hours during the year RES injections need to be curtailed. This can be equivalently regarded as DAM liquidity dropping to zero during these periods.

Simulation results show that, in general, for years 2022 and 2023 there are no RES curtailments, except for a very limited number of hours in 2023 in Scenarios 6 and 7, where FHR reaches its highest values (35% and 40%, respectively). It is concluded that the annual number of hours with non-zero RES curtailments increase as the considered FHR index increases, with most RES curtailments taking place during low net-load months (e.g. March, April, May, August, November). This is a strong indication that for these hours the wholesale market is not working properly and does not produce DAM clearing prices that express the short-term marginal generation cost.

Based on the above, the maximum threshold of the FHR should be between 25% and 30%, but clearly not higher than 30%.

ECCO is concerned however, that the imposition of this strict activity rule, while beneficial for the DAM liquidity and price discovery, in the long term may have negative impact on market efficiency as a whole and may introduce market distortions. It will obviously expose the uncovered sales of PPC and possibly of other Market Participants in the DAM in the long-term, to a spot price volatility risk, absent the application of other hedging instruments. International experience from the US and elsewhere clearly indicates that in the long term such an activity rule on the forward trading makes the market position of Market

Participants risky, especially in the absence of alternative hedging opportunities. It further reduces the liquidity of the Forward Market, making it less attractive for hedging by smaller players.

ECCO believes that a key issue affecting the DAM liquidity and performance is the physical delivery of the forward contracts through priority-price taking orders in DAM. We recommend to modify the design with respect to this parameter and neglect the automatic submission of priority-price-taking orders related to forward contract nominations in DAM. Instead, all physical bilateral contract volume should be free to be offered with priced economic offers in the DAM. This proposal is also consistent with the design in most energy markets around the world. The seller and the buyer of forward contracted quantities will continue to exchange cash payments based on the difference between the agreed contract price and the DAM price (swaps or contracts for differences – CfD). However, either the seller or the buyer would have the ability to re-evaluate the physical delivery decision through their daily forecasting on market prices vs their marginal costs allowing them to exempt the physical delivery obligation of PPT orders.

This proposal would ideally require that the MVC rule be reinstated so as to avoid to the most possible extend any price-dumping strategies. We recognize that the implementation of such an ex-ante floor level deviates from the approved current design options. Even for such a case **an ex-post price analysis of the forward contracted quantities offered in DAM and the concluded bilateral agreements would enable any regulatory intervention for keeping a level playing field**. ECCO believes that such a design proposal, under strict monitoring conditions, could have similar results to the existing FHR in terms of market power mitigation while at the same time could enhance the market efficiency allowing competitive supply/demand to take over the physical obligations of sellers/buyers depending on the short-term economic conditions in a market optimal manner. Obviously, in the absence of the proposed optimal design and strict price monitoring, the imposition of the maximum threshold of the FHR, as a transitional market power mitigation measure, remains an important design option.

Annex

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

Table 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	01/01/2023	Ag. Dimitrios 1	Lignite	274	30/04/2023
MYT_New CCGT	NG	803	01/10/2022	Ag. Dimitrios 2	Lignite	274	30/04/2023
Kardia_CHP	NG	105	01/10/2023	Ag. Dimitrios 3	Lignite	283	30/04/2023
TERNA-MORE CCGT	NG	858	01/07/2024	Ag. Dimitrios 4	Lignite	283	30/04/2023
New CCGT_IPP 1	NG	858	01/01/2025	Ag. Dimitrios 5	Lignite	342	31/12/2025
Metsovitiko	Water	29	01/01/2025	Megalopoli 4	Lignite	256	31/12/2023
				Meliti	Lignite	289	31/12/2023
Sum		**3,268**		**Sum**		**2,001**	