Market Assessment Report for 3rd Quarter of 2025

26 June to 25 September 2025

November 2025

This Report is prepared by the
Philippine Electricity Market Corporation –
Market Assessment Group
and approved by the
Market Surveillance Committee

Document Information Classification: Public

EXECUTIVE SUMMARY

As of the end of Q3-2025, the total registered capacity in the Wholesale Electricity Spot Market (WESM) was recorded at 29,890.1 MW, reflecting a 165.3 MW increase or 0.56% compared to the 29,724.8 MW recorded as of 25 June 2025. On a year-on-year basis, this represents a growth of 408.8 MW or 1.39% compared to the 29,481.3 MW registered in the same period last year.

While the WESM recorded a total registered capacity of 29,890.1 MW by the end of the billing quarter, only 68.64%, or an average of 20,516.25 MW, was offered/nominated in the market. This represents a 4.23% decrease compared to Q2-2025, which averaged 21,422.38 MW. On a year-on-year basis, however, it still represents a growth of 1,379.99 MW or 7.21% compared to Q3-2024. The observed decrease from Q2-2025 in offered/nominated capacity can be attributed to the increase in capacity on outage during this period.

The capacity not offered/nominated recorded a minimal increase of 0.70% by the end of Q3-2025, averaging 5,471.33 MW, compared to 5,433.20 MW in Q2-2025. This represents 18.30% of the total registered capacity.

The capacity of plants under Commissioning Test significantly decreased during the period, dropping by 443.77 MW or 69.02% compared to the preceding quarter. This reduction translates to a 0.67% share of the total registered capacity during the quarter.

Capacities on outage for the quarter accounted for 11.76% of the total registered capacities. By the end of the period in review, the capacities on outage increased by 1,236.62 MW or 54.27%, compared to 2,278.46 MW in Q2-2025. The increase in total outages was primarily driven by coal power plants, which saw an increase of 1,307.62 MW or 189.59% compared to the preceding quarter.

Coal power plants, which held the largest share of registered capacity, consistently generated the highest portion of electricity across all monthly billing periods. Despite a decline in coal's share during Q3 compared to Q2—from an average of 59.33% to 53.33%—coal remained the dominant source of generation. Despite the decrease, this reinforces coal's role as primary source of energy.

The overall system demand decreased by an average of 6.51% during the covered period, reaching 13,995.44 MW, a decline anticipated as Q3 2025 coincided with the typhoon season. The lowest demand was recorded at 10,615.33 MW on 20 July 2025 at 0555h trading interval. Coincidentally, the heat index was at its lowest, 31.2°C, on the same day.

As of the end of Q3-2025, the load weighted average prices (LWAP) were recorded at PHP4,038.06/MWh, reflecting a 6.69% decrease compared to the preceding quarter. On a year-on-year basis, this represents a 26.17% decrease compared to Q3-2024.

The load-market participants' spot market transactions experienced a slight decrease during Q3-2025, averaging 14.90%, compared to 20.81% in Q2-2025. This indicates that majority of total energy purchases remained covered by bilateral contracts.

Table of Contents

List of Figures

List of Tables

List of Annexes

QUARTERLY MARKET ASSESSMENT REPORT

This quarterly report presents an assessment of the results of the Wholesale Electricity Spot Market (WESM) operations for the Third Billing Quarter of 2025 (Q3-2025), covering the period 26 June to 25 September 2025, and how the market performed compared with the preceding quarters.

I. SUPPLY

A. Registered Capacity

As of the end of Q3-2025, the total registered capacity in the WESM reached 29,890.1 MW, reflecting a marginal increase of 165.3 MW or 0.56% compared to the 29,724.8 MW recorded as of 25 June 2025. On a year-on-year basis, this represents a growth of 408.8 MW or 1.39% compared to the 29,481.3 MW registered in the same period last year.

The capacity growth was primarily driven by the registration of new generating plants, which contributed to an aggregated capacity of 317.5 MW (*see Table 1*). This growth was partially offset by a net decrease of 152.2 MW resulting from changes in registered capacities among 27 existing plants and the cessation of operations of one (1) plant. Further details are provided in *Annex A – Plants with Change in Capacity*.

Table 1. New Generation Facilities for Q3-2025

Plant Type	Registered Capacity (MW)	Facility Name
Luzon		
Solar	30	Arayat 3A Solar Power Project
Solar	69.9	San Manuel Solar Power Plant
Solar	90	Lumbangan Solar Power Project
Solar	50.1	Luntal Solar Power Project
Visayas		
Solar	17.5	Taft Solar Power Plant
Mindanao		
Oil-Based	60	Iligan Diesel Power Plant Units 1 to 12

This trend indicates a continued but moderate growth in market participation, suggesting that while new capacity additions remain steady, operational adjustments and plant retirements create an offsetting impact.

Figure 1 shows that the WESM registered capacity continues to be predominantly composed of coal and natural gas plants, which together account for 56.5% of total capacity as of the end of Q3 2025. On a year-on-year basis, this reflects only a marginal change of approximately 1%, indicating the sustained dominance of these fuel types in the generation mix. The illustration also presents the changes in registered capacity by plant type relative to the preceding quarter. Overall, variations across all plant types were minimal, resulting in negligible shifts in percentage shares.

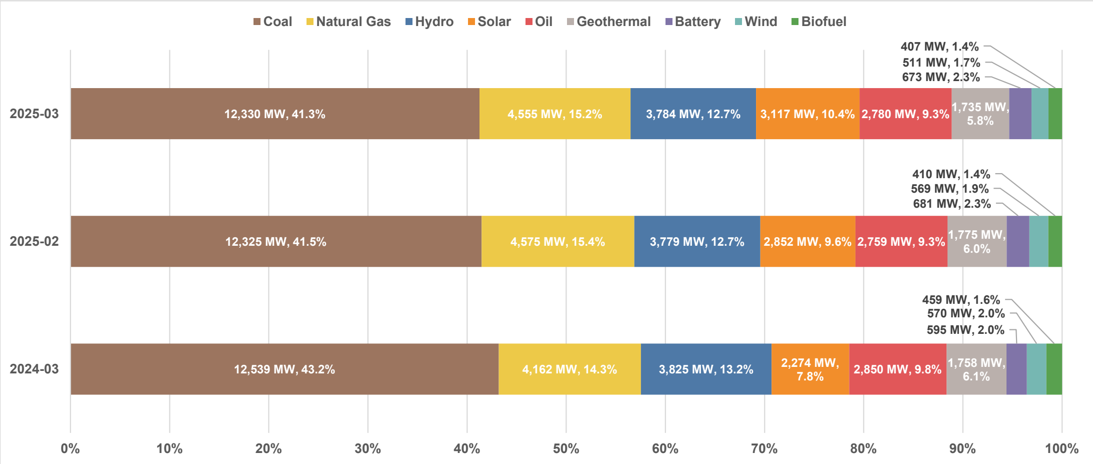


Figure 1. Registered Capacity by Plant type, as of the end of each billing quarter, Q3-2025, Q2-2025, and Q3-2024

B. Capacity Profile

This section provides an analysis and discussion on the capacity profile, encompassing capacity offered/nominated, capacity not offered/nominated, capacity on commissioning test, and capacity on outage. Further detailed statistics are provided in *Annex B – Capacity Profile*.

It should be noted that the observed gap during the covered period was related to a Market Intervention (MI) that was declared by the Market Operator (MO) on 16 and 19 September 2025. A detailed discussion of these MI events is provided in Administered Price (AP) section.

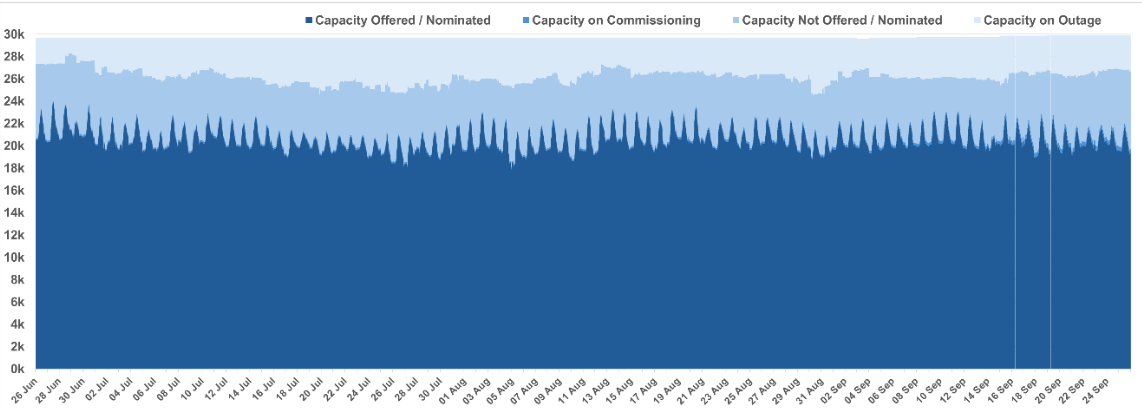
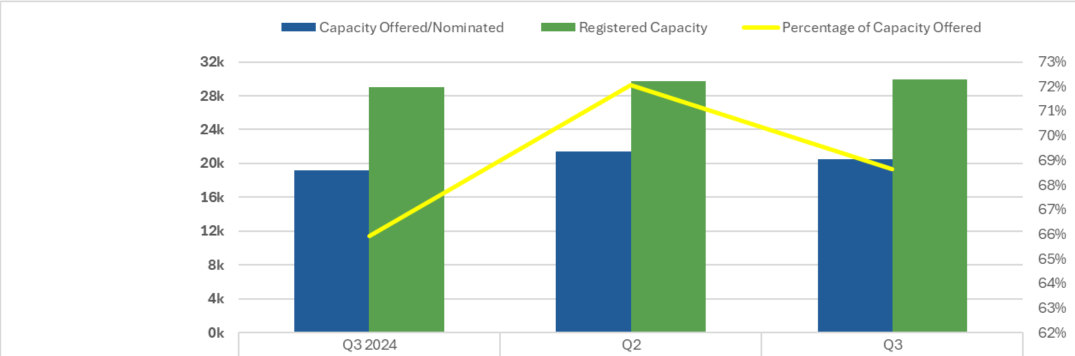


Figure 2. System: Capacity Profile, Q3-2025

Note: Missing portions represent the occurrence of Market Interventions

i. Capacity Offered/Nominated

The total registered capacity in WESM remained relatively stable during the quarter. However, the portion of capacity offered/nominated declined by 906.54 MW or 4.23% compared to the preceding quarter. Despite this slight reduction, the level of offered capacity continues to exceed that of the same period in the previous year, signaling a gradual improvement in market participation and resource utilization over time. The observed decrease can be attributed to the increase in capacity on outage during the current quarter. On a year-on-year basis, this still represents a growth of 1,379.99 MW or 7.21% compared to the total registered capacity in Q3-2024 *(see Figure 3)*.



	Q3 2024	Q2	Q3
Capacity Offered/Nominated	19,136.26	21,422.38	20,516.25
Registered Capacity	29,032.00	29,724.80	29,890.10
Percentage of Capacity Offered	65.91%	72.07%	68.64%

Figure 3. System: Offered/Nominated Capacity, Q3-2024, Q2-2025, and Q3 2025

On a per plant type basis, coal-fired power plants—holding the largest share of registered capacity—also accounted for the largest share of capacity offered/nominated at 45.98%, closely mirroring their proportion in total registered capacity. However, the average capacity offered/nominated for coal decreased by 1,451 MW compared to the preceding quarter, primarily due to an increase in capacity on outage.

Natural gas power plants ranked second, contributing an average share of 19.56% in total offered/nominated capacities, a level broadly consistent with their registered capacity share.

In contrast, Renewable Energy (RE) plants—which include geothermal, run-of-river (RoR) hydro, solar, wind, and biomass plants—accounted for approximately 23.27% of the average offered/nominated capacity during the current quarter. These resources benefit from preferential dispatch in WESM and therefore do not compete under the same conditions as conventional plants. The slight net increase in RE offers/nomination was primarily driven by significant rise from solar, hydro, and wind resources, resulting in a combined average increase of 427.92 MW.

During the quarter, several notable outages contributed to reductions in offered and nominated capacity *(see Table 2)*.

Table 2. List of Notable Outages

Date Range	Type of Outage	Plant Type	Number of Plants	Registered Capacity (in MW)
26 - 27 July 2025	Forced Outage	Coal	4	1,842.7
	Planned/Maintenance Outage	Coal	3	1,065.0
04 - 06 August 2025	Forced Outage	Coal	5	1,316.0
30 - 31 August 2025	Forced Outage	Coal	2	1,294.0
	Forced Outage	Natural Gas	2	611.0
	Planned/Maintenance Outage	Coal	1	688.0
23 - 25 September 2025	Forced Outage	Coal	2	938.0

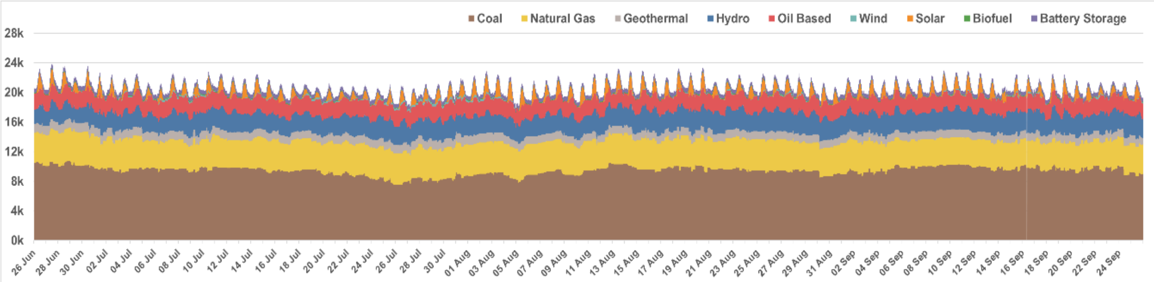
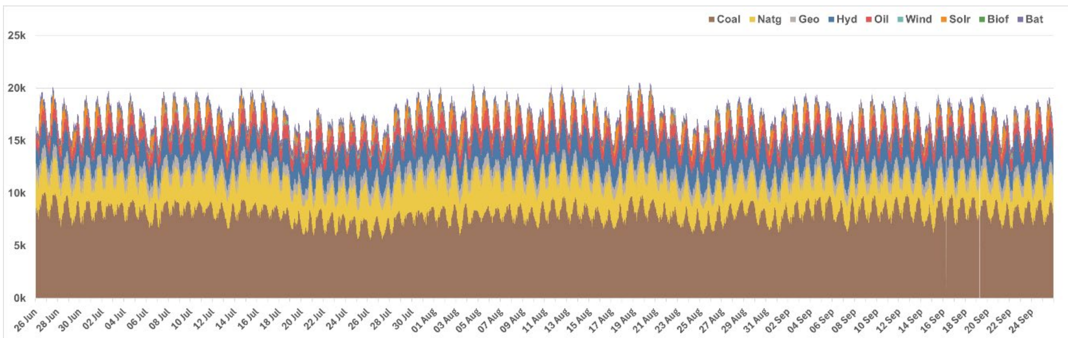


Figure 4 System: Offered/Nominated Capacity by Plant Type, Q3-2025

For the covered period, the average effective supply[1] was recorded at 17,025.61 MW, reflecting a 5.54% decrease compared to the preceding quarter. This decline suggests a reduction in available generation resources, largely influenced by increased outage levels among major plant types during the review period. Despite this quarter-on-quarter reduction, effective supply remains higher on a year-on-year basis, posting an increase of 458.93 MW or 2.77% relative to Q3 2024. This upward trend compared to last year indicates that, despite the impact of outages on supply, the overall system capacity and resource availability have improved over time.

The noticeable reductions in effective supply were observed around weekends when industrial and commercial demand typically declines. A similar decrease occurred on 21 August 2025 (Ninoy Aquino Day) and 25 August 2025 (National Heroes Day), both holidays when demand is typically lower than on regular weekdays. These reductions may likewise be attributed with the earlier discussion on dips in offered/nominated capacities due to outages, as several large coal and natural gas units were on forced or planned outages during these periods *(see Figure 5)*. However, it is important to note that effective supply was not only affected by outages but it was also constrained by ramp-rate limitations. Even when capacity is technically available, slower-ramping plants like coal cannot quickly adjust output (increase or decrease) in response to sudden demand changes. Thus, when demand falls quickly on weekends or holidays, or rises sharply after these periods, the system's effective supply is temporarily lower because only fast-ramping units are able to respond immediately. This dynamic illustrates why effective supply closely tracks not just total available capacity but also the system's ability to meet changes in demand



[1] Calculated for each 5-minute trading interval as the sum of the offered capacity of all scheduled generators considering their offered ramp rates, nominated loading level of nonscheduled generators and projected output of preferential dispatch generators, adjusted for any over-riding constraints imposed by the System Operator (SO), and reserve offers. Output of generators on testing and commissioning were considered based on the over-riding constraints imposed by the SO.

Figure 5 System: Effective Supply by Plant Type, Q3-2025

Coal power plants accounted for the largest share of the Real Time Dispatch (RTD) schedule at 54.78%, consistent with their substantial contribution to registered capacity. On a quarter-on-quarter basis, this share decreased by 4.81% compared to the preceding quarter, influenced by variations in demand and outage levels during the period. These demand variations, coupled with ramp-rate constraints, limited coal's ability to respond dynamically to shifting system requirements, reinforcing reliance on faster and more flexible resources for demand balancing. Despite this reduction, coal remained the primary source of dispatched energy. The decrease was further reinforced by lower demand and an increase in capacity on outage, which collectively reduced the relative share of coal-fired generation in the RTD schedule.

Natural gas power plants followed with a share of 19.34% in the RTD schedule, marking a 5.95% increase compared to the preceding quarter. This improvement was closely associated with the reduction in outage capacity, which enhanced the availability of natural gas units for dispatch.

Renewable Energy (RE) plants accounted for 25.52% of the total RTD schedule, reflecting their strong commitment based on forecasted availability.

The observed dips in RTD schedules during Q3 2025 corresponds to reduced system demand during weekends and non-working holidays that fell on weekdays. These demand reductions align with historical load patterns, where commercial and industrial consumptions decline while residential consumption does not fully offset the decrease. The alignment of these holidays with regular working days contributed to noticeable dips in RTD schedules compared to typical weekday demand levels.

Weather patterns also contributed to fluctuations in RTD schedules. Several weather disturbance alerts were issued by the System Operator (SO) affecting the Philippines during the quarter, including alerts for *Bising* (July 4–7), *Crising* (July 16–19), *Dante* (July 24), *Emong* (July 26), *Fabian* (August 8–9), *Gorio* (August 13), *Jacinto* (August 28), *Lannie* (September 6), *Mirasol* (September 18), and *Opong* (September 23–25)[2]. These disturbances likely impacted renewable generation, particularly solar and wind, due to reduced irradiance and adverse weather conditions.

In addition, cooler weather conditions associated with these disturbances may have contributed to lower system demand, as residential cooling requirements typically decline during stormy or cooler periods. The combined effects of reduced renewable output and lower demand contributed to RTD schedule variability during the quarter.

[2] PAGSA: Philippine Tropical Cyclone Name

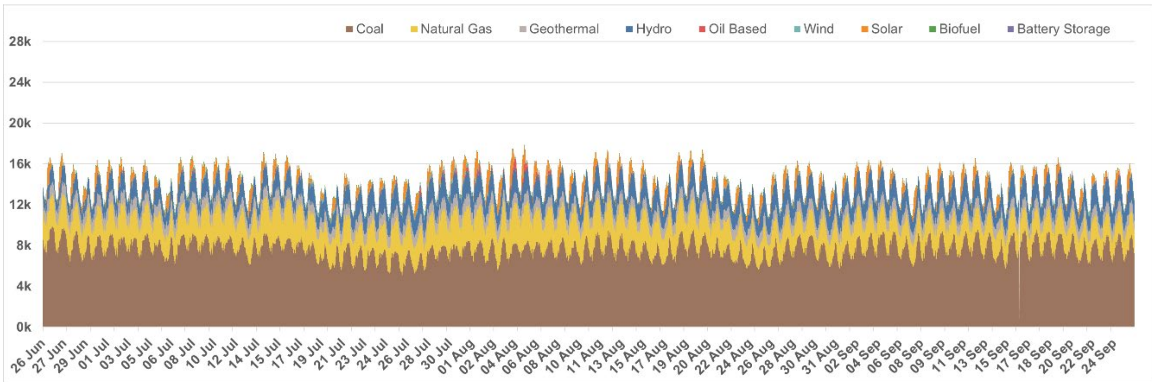


Figure 6 System: RTD Schedule by Plant Type, Q3-2025

ii. Capacity Not Offered/Nominated

The capacity not offered/nominated saw a minimal increase of 0.70% by the end of Q3-2025, which averaged at 5,471.33 MW when compared to Q2-2025 at 5,433.20 MW. This represents 18.30% of the total registered capacity.

Figure 7 provides the causes of capacities not offered/nominated, with outages[3] being the primary reason contributing to this occurrence. Aside from outages, resource constraints also affect the actual availability of power plants, providing valid reasons for not submitting offers/nominations. Furthermore, these are subject to the rigorous compliance monitoring procedures of PEMC's Enforcement and Compliance Office (ECO).

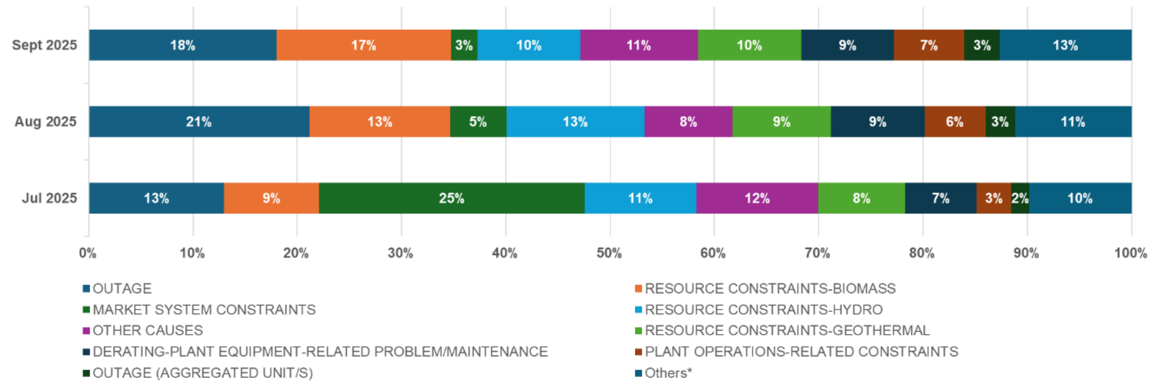


Figure 7. Reasons for Capacities not Offered/Nominated for Q3 2025[4]

The details and breakdown of Other*, which groups the remaining reasons for not submitting offers or nominations, are provided in *Annex C*.

iii. Capacity on Commissioning Test

Capacity of plants under Commissioning Test significantly decreased during the period, dropping by 443.77 MW or 69.02% compared to the preceding quarter. This reduction translates to a 0.67% share of the total registered capacity during the quarter.

[3] WESM Compliance Bulletin Issue No. 11.1

[4] Based on the information provided by PEMC-ECO

It was also observed that eight (8) plants had completed their testing and commissioning and commenced commercial operations *(see Table 3)*.

Table 3. Plants that stated commercial operations, Q3-2025

Plant Type	Facility Name	Registered Capacity (MW)	Remarks
Wind	Balaoi and Caunayan Wind Power Project Phase 1	22.4	Commercial operations started on 08 September 2025
Geothermal	Tiwi Geothermal Binary Power Plant	9.7	Commercial operations started on 26 June 2025
Battery	Lumban Battery Energy Storage System	50	Commercial operations started on 07 August 2025
Solar	Calatrava Solar Power Project	137.4	Commercial operations started on 08 August 2025
Solar	San Jose Solar Power Plant	15.3	Commercial operations started on 01 August 2025
Solar	Samal Solar Power Project Phase 1	35.8	Commercial operations started on 22 August 2025
Solar	Dagohoy Solar Power Project	20.2	Commercial operations started on 16 July 2025
Solar	Sto. Domingo Solar Power Plant	46.2	Commercial operations started on 15 August 2025

iv. Capacity on Outage

As of end of Q3-2025, the total capacities on outage reached 3,515.08 MW, representing 11.76% of the total registered capacities. This reflects an increase of 1,236.62 MW (54.27%) compared to the preceding quarter. However, on a year-on-year basis, this still represents a decrease of 468.40 MW or 11.76% compared to the capacities on outage in Q3-2024.

The changes in the capacities on outage are further discussed in the succeeding sub-sections.

1. Capacities on Outage by Plant Type

A breakdown of capacity on outage by plant type shows that coal power plants accounted for the largest share, comprising 56.82% of the total capacity on outage during the quarter. Notably, the average capacity on outage for the said resource type increased by 1,307.62 MW or 189.59% compared to the preceding quarter, primarily due to the prolonged outage of several coal plants *(see Figure 8)*. This surge in coal outages underscores the vulnerability of the system to unplanned and extended maintenance events, given the coal's critical role in the generation mix.

Natural gas power plants remained a significant factor in overall outages, accounting for 11.83% of the total capacity on outage, making it the second largest contributor among all plant types. However, on a quarter-on-quarter comparison, the average capacity on outage of natural gas plants decreased by 241.54 MW or 36.75% compared to the preceding quarter. This improvement is caused by the resumption of large natural gas plants at the start of the quarter in review. Most of the long-duration outages for these plants were attributed to temperature trouble and joint repair.

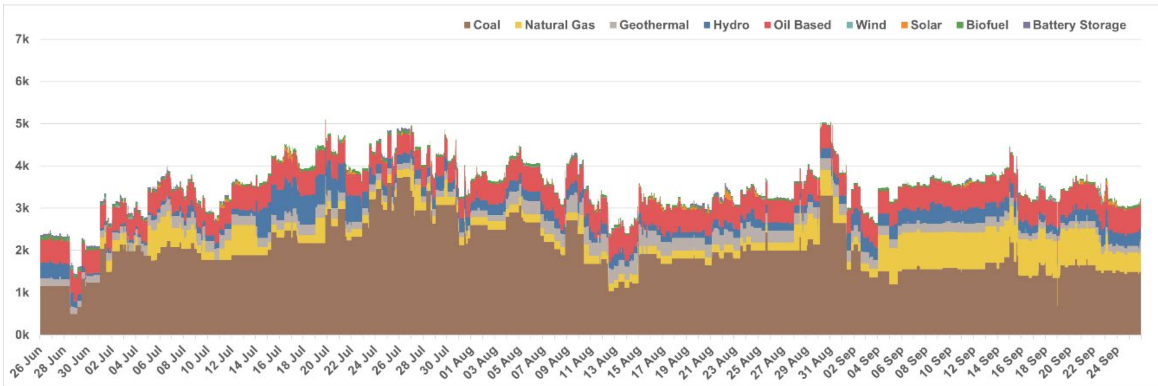


Figure 8. System: Capacity on Outage by Plant Type, Q3-2025

Furthermore, based on the month-on-month analysis, September 2025 billing month recorded the highest average monthly outage level at 3,674.19 MW. The peak outage of 5,129.28 MW occurred on 30 August 2025 during the 0705h to 0800h trading intervals. The spike in outage was triggered by a forced outage of a large coal plant due to air pressure in the control system of a power plant drops below the required operating level, in addition to the 3,835.28 MW of capacity already on outage that day. For natural gas plants, the September 2025 billing month recorded an average capacity on outage of 672.83 MW, a 99.5% increase compared to the July billing month average of 337.25 MW. This can be attributable to the planned outage of Sta. Rita Natural Gas Power Plant Unit 1 (263 MW) starting 03 September 2025 until 24 October 2025 and extended planned outage of Ilijan Natural Gas Combined-Cycle Power Plant (220 MW) starting 04 September 2025 to 22 September 2025.

2. Capacities on Outage by Category

This section reviews outages by category during the billing quarter. The overall increase in total outages was primarily driven by a surge in planned outages, which averaged 1,606.55 MW, marking a 379.06% increase compared to the preceding quarter *(see Figure 9)*. This sharp rise can be attributed to the Department of Energy (DOE) directive prohibiting power plants from commencing planned outages during the summer season, a measure designed to ensure grid reliability during peak demand months[5]..

[5] DOE Department Circular No. DC2020-02-0004

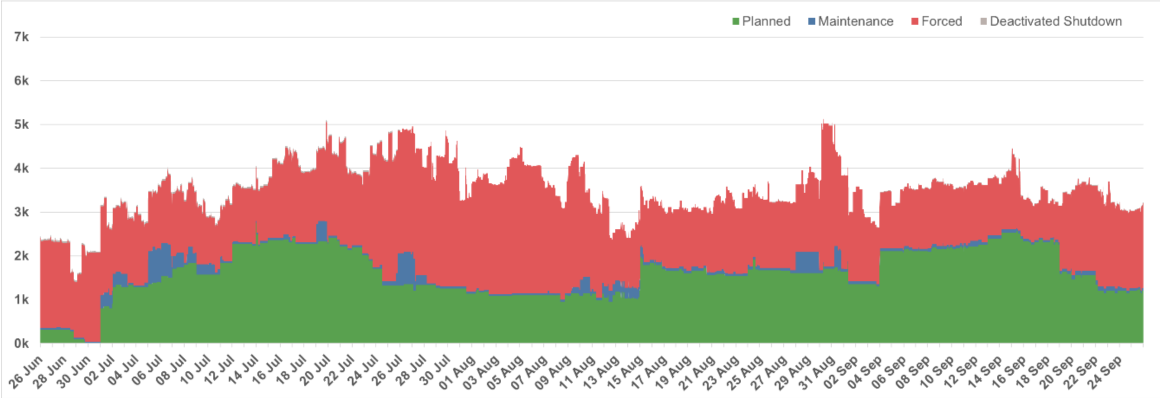


Figure 9. System: Capacity on Outage by Category, Q3-2025

C. Generation Mix

Coal power plants, which held the largest share of registered capacity, consistently generated the highest portion of electricity across all monthly billing periods. Despite a decline in coal's share from 59.33% in Q2 to 53.33% in Q3, it remained the dominant source of generation, reinforcing its role as the primary source of energy *(see Figure 10)*.

Natural gas generation exhibited a notable increase throughout the billing quarter, consistent with earlier discussion on the return of service of several large natural gas plants.

Moreover, RE plants collectively accounted for 26.02% share of the total generation mix for Q3-2025, an improvement from the 22.7% RE share in the preceding quarter. This growth was primarily driven by an increase in share of hydro plants, while geothermal plants maintained a steady contribution of around 8–9%. Although RE penetration is improving, it remains below the government's target. As outlined in the Philippine Development Plan (PDP) 2023–2050, the DOE aims to raise the RE share to 35% by 2030 (including off-grid). At present, the country is only 8.98% short of this goal, underscoring the need for accelerated investment and policy support to meet the target within the next five years.

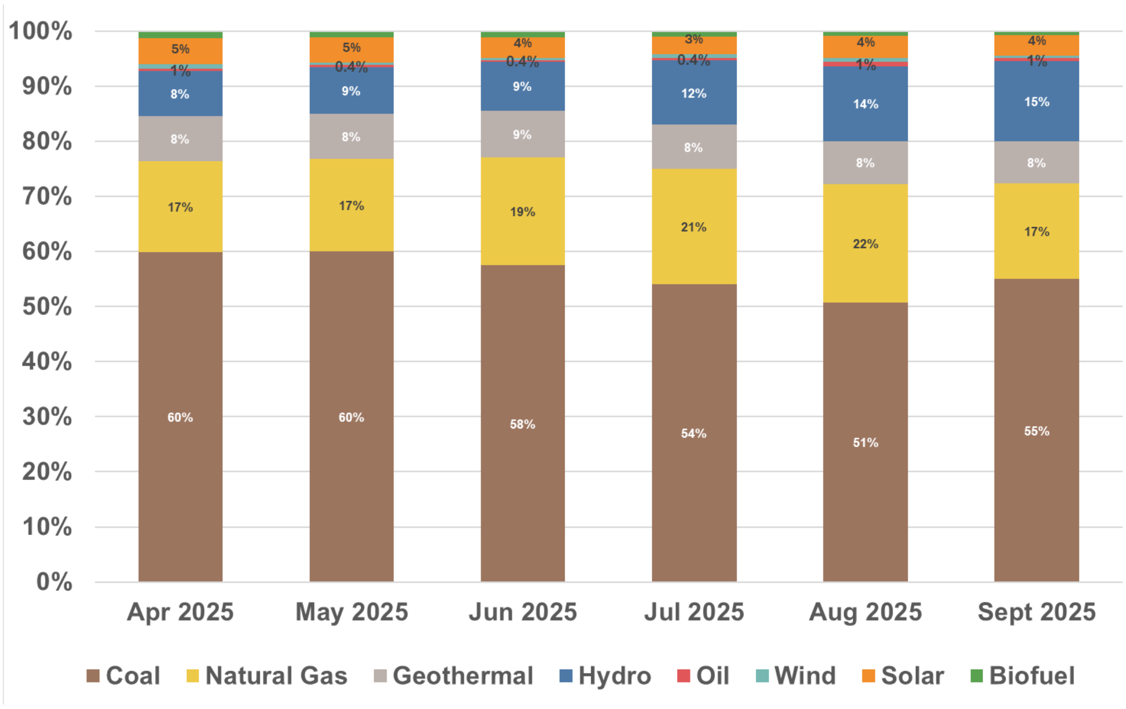


Figure 10. Generation Mix (Based on Metered Quantity) – Jun 2025 to Sept 2025

Hourly generation by plant type shows a consistent daily demand cycle, with peaks typically occurring during daytime hours and troughs at night. Coal remains the dominant contributor throughout the period, forming the base load and accounting for the largest share of generation. Natural gas provides significant mid-merit support, while renewable sources add variability and seasonal flexibility *(see Figure 11)*.

Consistent with the earlier discussion on RTD schedules, the observed dip in hourly generation corresponds to reduced system demand during weekends and non-working holidays that fell on weekdays, resulting in reduced metered quantity or energy output. These periods, combined with the cooler weather conditions, led to lower system demand and consequently reduced dispatched energy across all plant types.

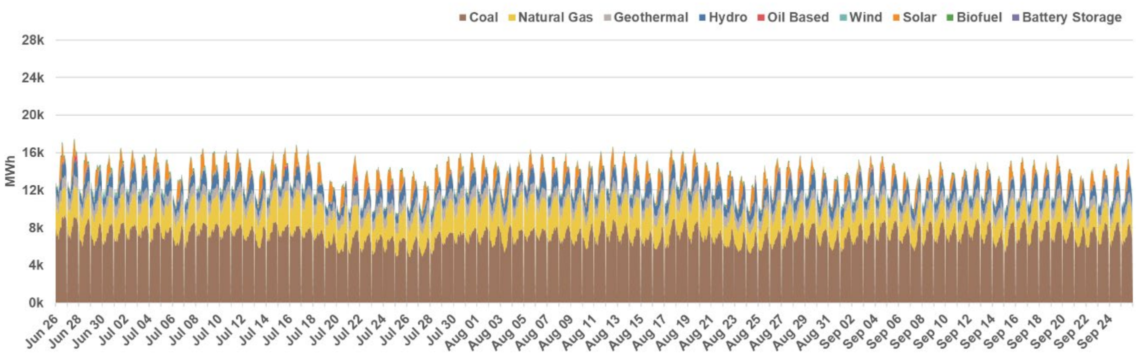


Figure 11. Hourly Generation Metered Quantity – Q3-2025

II. DEMAND

The overall system demand decreased by an average of 6.51% during the covered period, reaching 13,995.44 MW, a decline anticipated as Q3 2025 coincided with the typhoon season. The lowest demand was recorded at 10,615.33 MW on 20 July 2025 during the 0555h trading interval. On the same day, the heat index also reached its lowest at 31.2°C. Cooler weather conditions typically reduce the use of cooling appliances, contributing to lower consumption. Conversely, the highest demand reached 17,961.7 MW on 08 August 2025 at the 1425h trading interval due to the naturally high demand during weekday.

Figure 12 presents the temporal dynamics among effective supply, system demand, and demand inclusive of reserve requirements across all dispatch intervals for the quarter. Despite an increase in capacity on outage, amounting to 11.76% of the total registered capacity, the system's effective supply consistently met both energy and reserve requirements. However, localized grid alerts notices were issued by the SO during the quarter for the Visayas and Mindanao Grids, indicating potential concerns in resource availability *(see Figures 13,14, and Table 4)*.

Table 4 List of Grid Alerts as issued by the SO

Date	Region	Alert	Interval	Remarks
01 August 2025	Visayas	Yellow	1900h - 2000h	Total forced outage of around 204 MW and a total deration of around 219 MW
	Mindanao		1900h - 2000h	Total capacity on forced outage of around 579 MW and a total deration of around 59.3 MW
04 August 2025	Visayas	Yellow	1900h	Total forced outage of approximately 221.1 MW and a total deration of around 369.9 MW
05 August 2025	Visayas	Yellow	1400h to 2100h	Total forced outage of approximately 385.1 MW and a total deration of around 348.4 MW
06 August 2025	Visayas	Yellow	1600h, 1800h, and 1900h	Total forced outage of approximately 385 MW and a total deration of around 340.1 MW

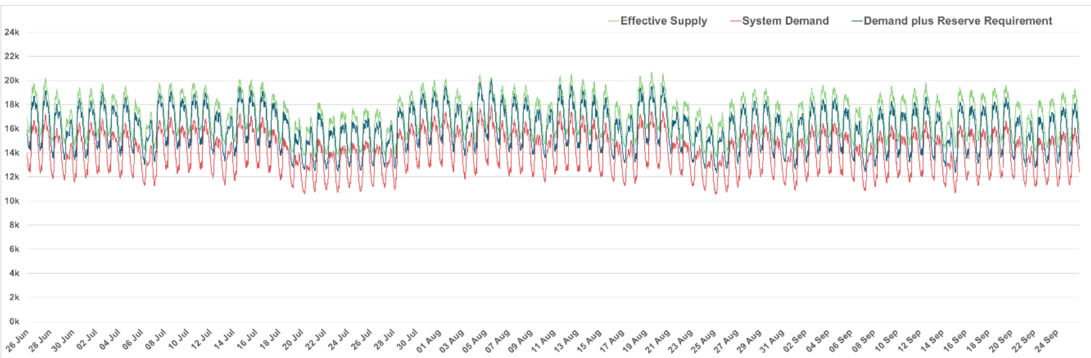


Figure 12. Demand, Supply and Demand plus Reserve Schedule, Q3-2025

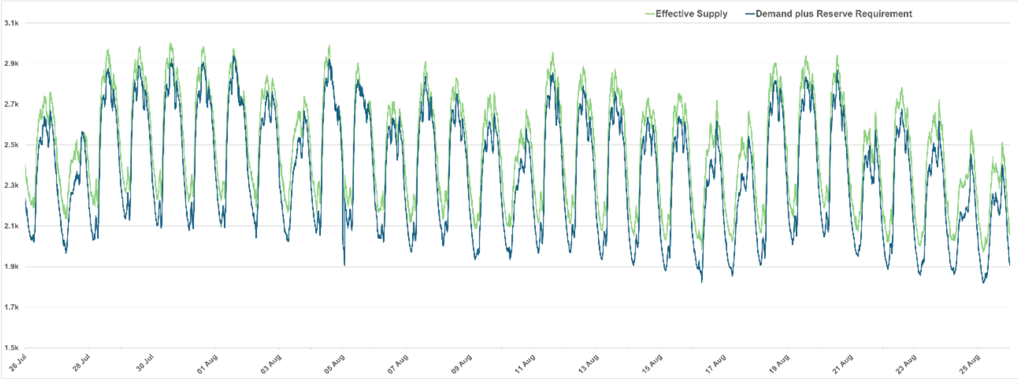


Figure 13. Supply and Demand plus Reserve Schedule - Visayas, August-2025

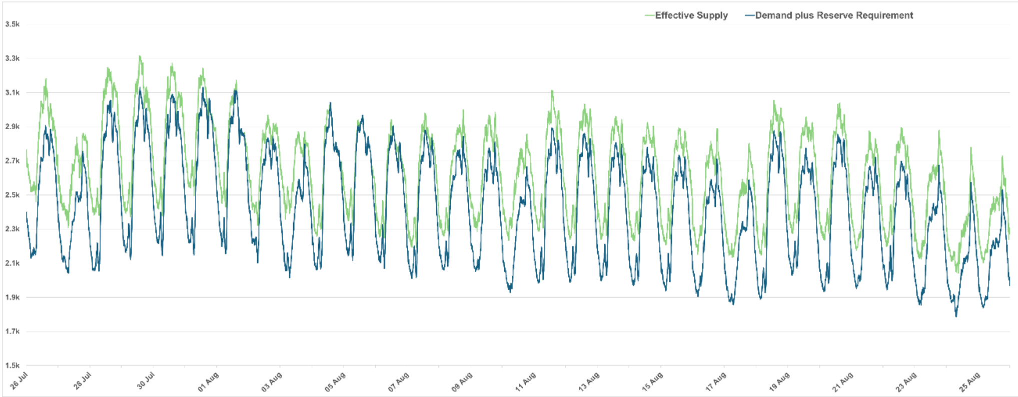


Figure 14. Supply and Demand plus Reserve Schedule - Mindanao, August-2025

Electricity demand can be attributable to variations in the heat index, indicating that demand generally follows changes in the heat index, with higher temperatures typically driving increased consumption due to cooling requirements. As noted earlier, the lowest demand coincided with the lowest recorded heat index of 31.2°C on the same day *(see Figure 15)*. However, variations in demand are not solely temperature-driven. The type of day, such as weekends or non-working holidays, also plays a significant role. During these periods, commercial and industrial activity declined, resulting in reduced electricity demand even when temperatures remain relatively high.

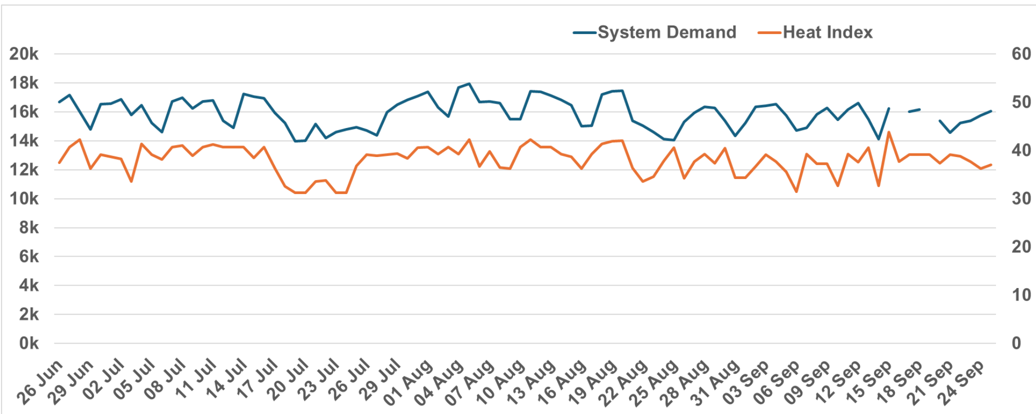


Figure 15. Daily Max Demand and Max Heat Index[6], Q3-2025

[6] Visual Crossing Corporation: https://www.visualcrossing.com/weather-history/Philippines/us/ - Maximum feels like temperature

III. MARKET PRICE OUTCOME

A. Market Prices

The average LWAP for Q3-2025 was recorded at PHP3,872.19/MWh, reflecting a 10.53% decrease compared to the preceding quarter. On a year-on-year basis, this represents a 29.21% decrease from Q3-2024 *(see Figure 16)*. However, the per interval LWAP exhibited fluctuating patterns, primarily influenced by tight supply conditions, regional outages, and demand fluctuations.

Significant price spikes occurred on 07 August 2025, with 47 price spikes recorded across Luzon, Visayas, and Mindanao. These were concentrated during the morning off-peak (0825h) and late afternoon to evening intervals (1425h to 2015h). The price spikes affecting Visayas and Mindanao were likewise driven by the tight supply conditions compounded by the normal reduction in nominated capacity from solar plants during late afternoon hours. Furthermore, this coincided with a gradual increase in demand, averaging 11 MW in Visayas between 1805h and 1845h and 8 MW in Mindanao between 1825h and 1835h.

Additionally, the morning off-peak spike was similarly demand-driven, triggered by a 42 MW increase across these regions. Overall, Visayas demand rose by an average of 140 MW from 1500h to 2030h compared to the previous day, intensifying pressure on available capacity. In Luzon, offered capacity of hydro plants declined by 181 MW at 1805h, 185 MW at 1905h, and 366 MW at 2005h due to Kalayaan Pump-Storage Power Plant pumped operations, which triggered the price spike.

During these events, HVDC links between the regions reached their maximum limits of 250 MW for Luzon-Visayas and 450 MW for Visayas-Mindanao, resulting in price separations across the regions.

Other notable price spike occurred on 05 August 2025, with 26 price spikes occurred from 0800h to 1005h primarily affecting the Visayas-Mindanao region. These spikes were driven by tight supply conditions coupled with rising demand, which increased by an average of 32 MW per interval during the morning. The offered capacity from hydro plants in Mindanao significantly dropped in the morning by 75 MW at 0620h, 90 MW at 0815h, and 131 MW at 0930h and in the evening, by 76.2 MW at 2005h. Due to sustained high-price conditions, the Secondary Price Cap was imposed on 158 intervals from 1010h to 2315h. Compounding the issue, the HVDC link between Luzon and Visayas operated at its maximum transfer limit of 250 MW, restricting inter-regional support and resulting in price separation between Visayas and Mindanao.

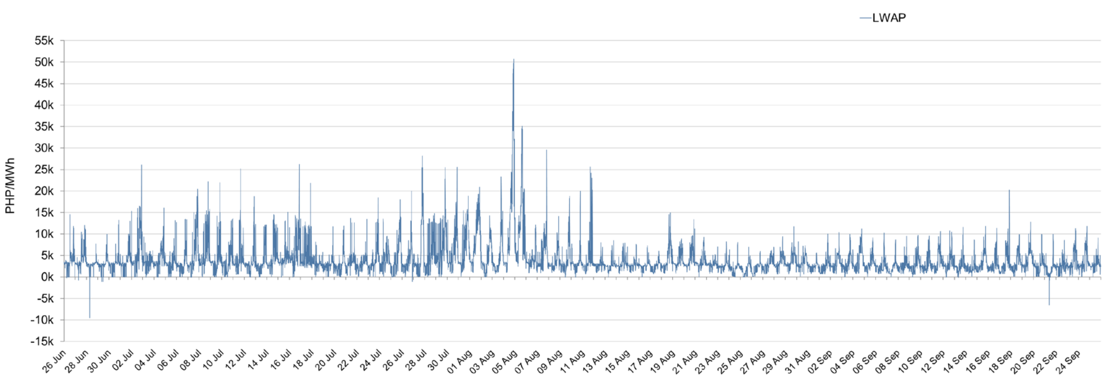


Figure 16. System: Market Price Trend, Q3-2025

In line with the earlier discussion on reduced load during weekends and holidays, Table 5 presents the corresponding average LWAP by day type. The data shows that LWAP levels during weekends and holidays were lower compared to weekdays.

Table 5 LWAP per Day Type, Q3-2025

Type of Day	LWAP Php/MWh
Weekday	4,168.64
Weekend	3,119.84
Holiday	2,629.84

B. Price Distribution

During Q3-2025, LWAP remained predominantly low, with 79.19% of trading intervals registering prices within the PHP 0/MWh to PHP 5,000/MWh range. This trend persisted despite periods of tight supply and elevated outage levels, particularly during the August billing month. The impact of these high-price intervals was offset by the prevalence of low prices in July and September, resulting in an overall subdued quarterly average *(see Figure 17).*

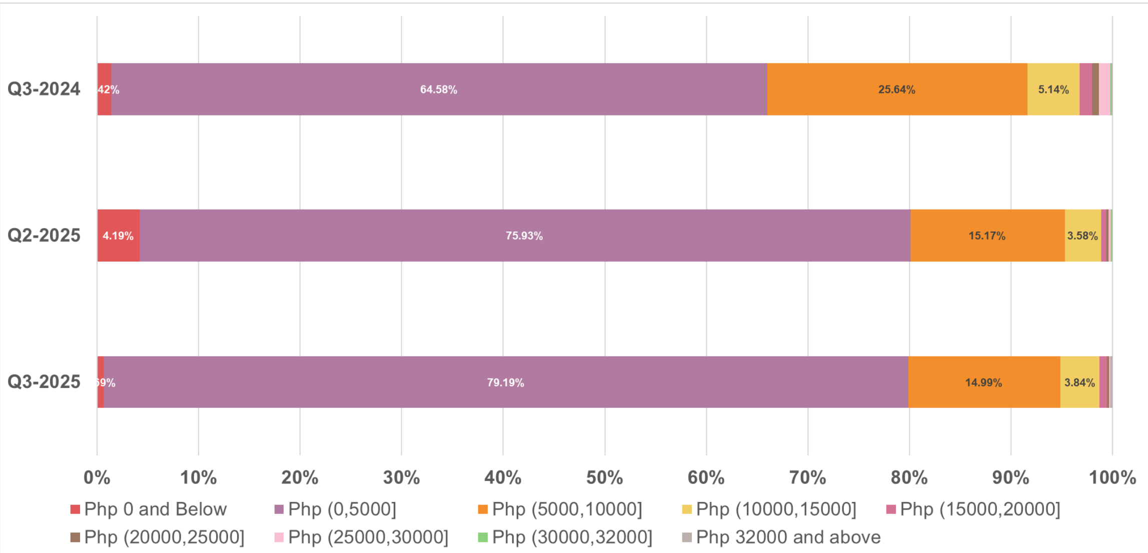


Figure 17. System: Market Price Band, Q3-2024, Q2-2025, and Q3-2025

Table 6 presents the tabular distribution of market prices across the billing months covered in Q3 2025, offering a detailed breakdown of price intervals and their corresponding frequency. This representation complements the visual trend shown in Figure 17 by quantifying the proportion of trading intervals within each price bracket.

Table 6. Details System: Market Price Band, Q3-2025

Price Range (Php/MWh)	%Distribution		
	July 2025	Aug 2025	Sept 2025
Php 0 and Below	0.83%	0.40%	0.39%
Php (0,5000]	73.19%	79.78%	84.42%
Php (5000,10000]	17.45%	13.73%	14.55%
Php (10000,15000]	7.39%	3.37%	0.62%
Php (15000,20000]	0.73%	1.47%	-
Php (20000,25000]	0.21%	0.39%	0.01%
Php (25000,30000]	0.20%	0.09%	-
Php (30000,32000]	-	0.09%	-
Php 32000 and above	-	0.67%	-

C. Market Pricing Conditions

During Q3-2025, the WESM was mostly under normal pricing conditions for 25,067 trading intervals or at 94.63% of the time. However, other intervals were placed under various market pricing adjustments / corrections as follows:

i. Pricing Error Notice (PEN) [7]

There were 542 total trading intervals observed with system-wide PEN issuances during Q3-2025 which were related to inappropriate input data that subsequently affected the market outcomes.

ii. Price Substitution Methodology (PSM)[8]

As a result of severe congestion events in the electricity transmission network, PSM was applied on a system-wide basis across 623 trading intervals—reflecting a 94.08% increase compared to Q2-2025. The increase indicates higher instances where market prices required adjustment to address extreme price separations caused by transmission network congestion. The average price during the instances of PSM imposition was noted at PHP 5,180.99/MWh *(see Table 5)*.

[7] Section 5 of the Price Determination Methodology provides that the Market Operator (MO) performed a pricing re-run upon issuance of pricing error notice, notwithstanding the application of an automatic pricing re-run.

[8] Section 6.2.5 of the Price Determination Methodology provides the price substitution methodology shall be implemented in all the regions where the WESM is in operation. In cases where a region/s has no interconnection with other regions, or has no exchange of power with other regions, this region/s shall be separately assessed for the application of the price substitution methodology.

Table 7. Congestion caused by PSM

Line ID	Line Name and Rating	Frequency of Congestion
DASMA_CORR	DASMARINAS CORRIDOR	336
3DASMA_TR3	03DASMAEHV	149
11MARA_13BUN2	MARAM-BUNAW 230 kV LINE 2	74
AG2_TO_BALO	AGUS 2-BALOI TRANSMISSION LINE	21
1MEXI_1HER2	MEXICO-HERMOSA 230 kV LINE 2	20
1MEXI_1HER1	MEXICO-HERMOSA 230 kV LINE 1	8
09AURO_09NAG2	AUROR-NAGA 138 kV LINE 2	7
3BINA_3DAS2	BINAN-DASMAEHV 230 kV LINE 2	1
12BISL_13NAB1	BISLI-NABUN 138 kV LINE 1	1
3STRO_3CLA1	STROSA-CLACA 230 kV LINE 1	1
3BINA_3DAS1	BINAN-DASMAEHV 230 kV LINE 1	1

iii. Administered Price (AP)

Market Interventions (MIs) remained a recurring factor in the pricing dynamics during the billing quarter. Recent MIs affecting 17 trading intervals were placed under system-wide Administered Prices (AP) following Market Operator's (MO) Business Continuity Plan (BCP) Simulation. The specific triggers were as follows:

- 16 and 19 September 2025 - the failure of the Market Management System (MMS) to generate RTD results following the switchover of the MMS from the main site (Eton Site) to the backup site (Cebu Site).

The APs during the MI events vary significantly as they are determined under market conditions different from normal operations. These APs may impact both generators and consumers, as additional compensation mechanisms are applied during these instances. These costs are subsequently recovered over extended periods, influencing overall market settlements and potentially affecting forward price expectations.

Currently, the MSC is looking into enhancing the methodology in determining APs to better reflect prevailing market conditions when applying substitute pricing.

Table 8. Generator Weighted Administered Prices on Market Intervention Events

Date	Affected Interval	Region	Price Before the MI (Php/MWh)	Administered Price during the MI (Php/MWh)			Price After the MI (Php/MWh)
16 September 2025	8 Intervals (0725h - 0800h)	Luzon, Visayas, and Mindanao	1,588.31	29.18%▲	2,051.75	31.77%▼	3,007.21
	1 Interval (0920h)		1,602.77	21.84%▲	1,952.77	29.23%▼	2,759.26
	1 Interval (0935h)		2,685.93	6.66%▼	2,480.02	11.06%▼	2,788.43
18 September 2025	4 Intervals		990.07	55.55%▲	1,540.10	58.56%▼	3,716.10
	3 Intervals (1115h - 1125h)		4,081.46	27.35%▼	2,965.30	9.22%▼	3,266.55

D. Secondary Price Cap (SPC)[9]

For Q3-2025, Secondary Price Cap (SPC) issuance was recorded to an average of 255 intervals across the entire system. This trend reflects prevailing tight supply-demand conditions during the period, primarily driven by elevated outage levels and transmission constraints associated with the Luzon-Visayas and Mindanao-Visayas HVDC interconnections. These factors collectively contributed to heightened market stress, necessitating the activation of SPC to mitigate extreme price volatility *(see Table 9)*.

Table 9. Monthly Pricing Condition for Q3-2025

		Normal		Pricing Error Notice		Price Substitution Methodology		Secondary Price Cap		Administered Price	
Region/Grid	Billing Month	Count/Total No. of Trading Interval/s	%	Count/Total No. of Trading Interval/s	%	Count/Total No. of Trading Interval/s	%	Count/Total No. of Trading Interval/s	%	Count/Total No. of Trading Interval/s	%
Luzon	July 2025	8,330	96.41%	157	1.82%	153	1.77%	0	0.00%	0	0.00%
	August 2025	7,897	88.45%	331	3.71%	453	5.07%	247	2.77%	0	0.00%
	September 2025	8,840	99.01%	54	0.60%	17	0.19%	0	0.00%	17	0.19%
Visayas	July 2025	8,332	96.44%	157	1.82%	151	1.75%	0	0.00%	0	0.00%
	August 2025	7,887	88.34%	331	3.71%	451	5.05%	259	2.90%	0	0.00%
	September 2025	8,840	99.01%	54	0.60%	17	0.19%	0	0.00%	17	0.19%
Mindanao	July 2025	8,332	96.44%	157	1.82%	151	1.75%	0	0.00%	0	0.00%
	August 2025	7,887	88.34%	331	3.71%	451	5.05%	259	2.90%	0	0.00%
	September 2025	8,840	99.01%	54	0.60%	17	0.19%	0	0.00%	17	0.19%

IV. GENERATOR OFFER PATTERN

This section examines generator-trading participants' offer patterns, as submitted to the WESM via the Market Participant Interface (MPI), in accordance with WESM Rules Clause 3.5.

Coal-fired power plants maintained offer price patterns consistent with the preceding quarter, with a substantial share of capacity submitted at or below PHP 0/MWh. This trend reflects the typical operational strategy of coal plants, which function as baseload generators committed to high dispatch levels to secure delivery of their contracted quantities. The prevalence of zero or negative offers may also be influenced by bilateral contract obligations or cost recovery mechanisms independent of spot market revenues *(see Figure 18)*.

On a quarter-on-quarter basis, a slight variation was observed: offers within the PHP 0 to 5,000/MWh range decreased by 2%, while offers at PHP 0 and below increased by 2%. Coal-based offers remained predominantly low, contributing to sustained competitive pricing in the market.

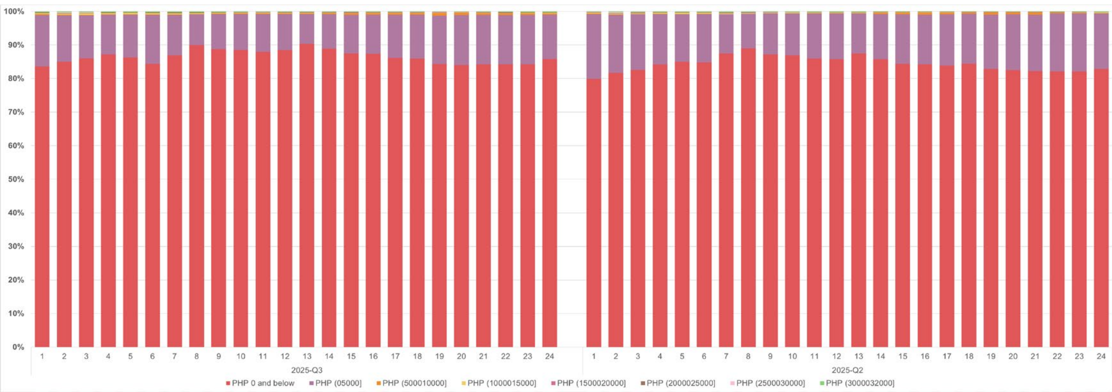


Figure 18. Coal Power Plants Offer Pattern – Q2-2025 and Q3-2025

[9] ERC Resolution No. 7 Series of 2021, if the Cumulative Price Threshold (CPT) was breach on the 72^{nd} hours regional/islanding, Secondary Price Cap (SPC) will be imposed

Natural gas-fired power plants exhibited similar offer behavior, with offers clustered at PHP 0/MWh and below, consistent with their operational role in baseload and mid-merit dispatch. This pricing strategy is largely shaped by long-term bilateral contracts and regulatory cost-recovery frameworks, which insulate these units from spot market price volatility. By submitting zero or negative offers, generators secure their position in the dispatch stack, ensuring reliability and compliance with contractual obligations *(see Figure 19)*.

In addition, this trend may possible be reinforced by fuel supply arrangements, including take-or-pay provisions, and the operational requirements of combined-cycle units, which necessitate stable load factors to sustain efficiency.

Figure 19. Natural Gas Power Plants Offer Pattern – Q2-2025 and Q3-2025

Hydropower plants recorded a notable increase in offers within the PHP 0 to PHP 5,000/MWh range during the review period, rising by 11.14% compared to the preceding quarter, as reflected in the market offer distribution. The data also highlights visible pumping nominations, particularly from the Kalayaan Pumped Storage Plant, which absorbed excess supply during low-price hours and repositioned energy for subsequent use *(see Figure 20)*.

The decrease in high-price offers can be attributed to the increase water availability during the typhoon season, which expanded the dispatchable capacity of hydro plants. At the same time, the pumping activity indicates optimization of reservoir operations to conserve water while maintaining flexibility for grid support.

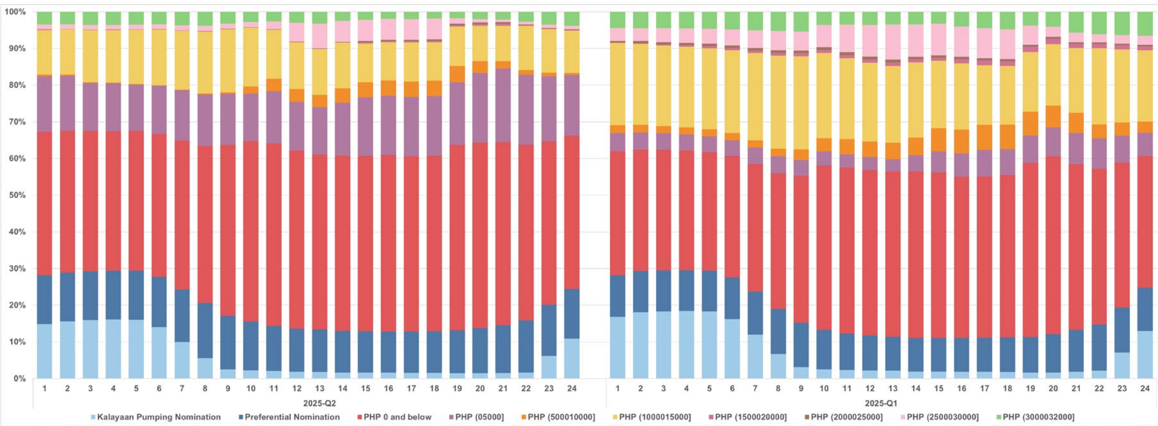


Figure 20. Hydro Power Plants Offer Pattern – Q2-2025 and Q3-2025

Oil-based power plants continued to concentrate offers in the higher price ranges, particularly between PHP 25,000 to PHP 32,000/MWh, across both Q2-2025 and Q3-2025. This persistent bidding patterns reflects their role as peaking units, typically dispatched only during periods of tight supply or high demand rather than for continuous operation *(see Figure 21).*

Offers above PHP 25,000/MWh showed a slight increase, while offers at PHP 5000 and below remained minimal compared to the preceding quarter. This strategy aligns with cost structures, as oil-fired generation is more expensive relative to coal, natural gas, or hydro resources. As a result, these plants contribute to price spikes in the market only when cheaper resources are insufficient to meet demand.

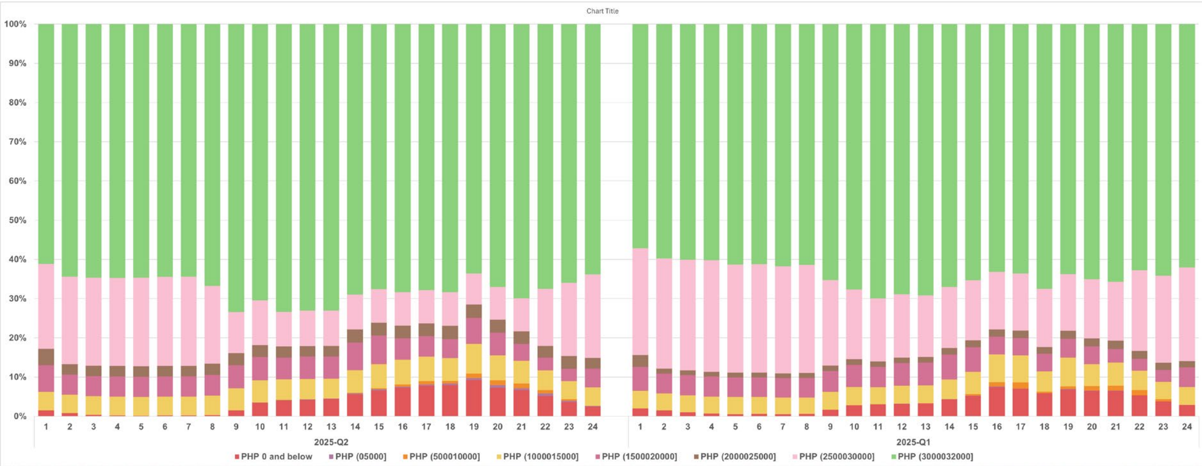


Figure 21. Oil-based Power Plants Offer Pattern – Q2-2025 and Q3-2025

V. STRUCTURAL COMPETITION INDICES

A. Residual Supply

The Market Residual Supply Index (RSI), plotted against the number of pivotal suppliers, averaging 100.48% in Q3-2025 *(see Figure 22)*, up from 99.16% in Q2-2025 and 97.65% in Q3-2024. RSI measures the extent to which the market can meet demand without relying on a single supplier. A higher RSI indicates that the system has enough residual capacity to maintain supply and satisfy demand even if the largest supplier is removed. While RSI remained above 100%, signaling adequate residual capacity, the underlying conditions were less favorable than the previous quarter. Specifically, Q3-2025 experienced lower offered capacity and higher outage levels, which constrained available supply and increased system vulnerability.

Despite RSI above 100%, higher outage rates and reduced offers increased the likelihood of pivotal suppliers during peak intervals, amplifying market power risk and potential price volatility. In contrast, periods with higher offered capacity and lower outages (e.g., Q2-2025) provide greater competitive pressure, reducing reliance on a few suppliers and stabilizing prices.

Notably, the average market prices for intervals where RSI below 100% was PHP 5,674.31/MWh, whereas intervals with RSIs above 100% recorded a lower average price of PHP 2,762.29/MWh. This demonstrates the typical inverse relationship between RSI and market prices.

It is also worth noting that when the RSI peaked at 109.48%, the corresponding market price was PHP 1,557.08/MWh. Conversely, when the RSI was at its minimum recorded at 92.98%, the price was at PHP 1,636.22/MWh, underscoring the relationship between the supply, demand, and prices. Table 8 presents the occurrences of both minimum and maximum RSI values along with their corresponding market prices, and vice versa.

Table 10. RSI vs LWAP, Q3-2025

	RSI		Date and Time Interval	Price		Date and Time Interval
Max	109.48	1,557.08	09/15/2025 3:55	50,708.91	93.26	08/04/2025 21:50
Min	92.98	1,636.22	09/19/2025 7:30	- 9,431.86	104.75	06/28/2025 7:05

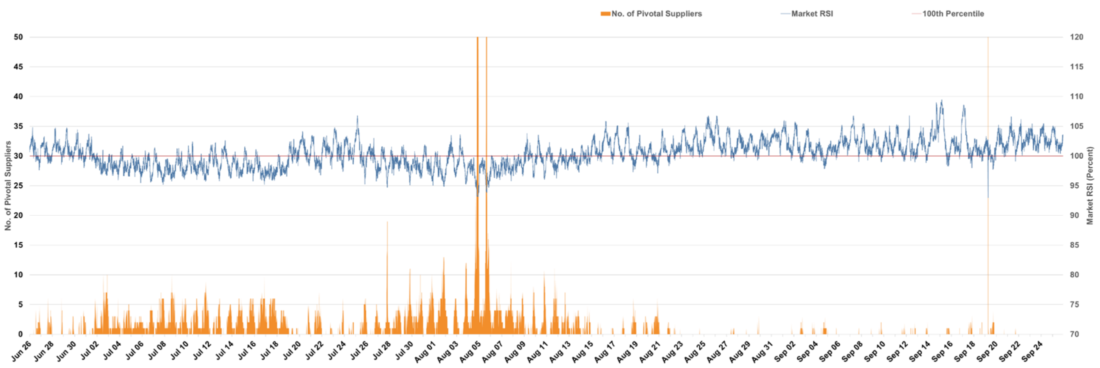


Figure 22. Market RSI vs. Pivotal Suppliers, Q3-2025

During Q3-2025, there were notable instances where the total number of pivotal suppliers exceeded 180 *(see Table 11)*. This reflects the impact of RSI values in the range of 92–94%, which are below the 100% threshold. An RSI below 100% indicates that, after removing the largest supplier, the remaining capacity is insufficient to meet demand. This condition forces the system to rely heavily on multiple suppliers to maintain stability, increasing the number of pivotal suppliers and reducing competitive pressure.

Table 11. Notable Number of Pivotal Suppliers, Q3-2025

Time interval	RSI	Number of Pivotal Suppliers
08/05/2025 16:20	93.8428	260
08/05/2025 15:15	94.0398	259
09/19/2025 7:30	92.9818	247
08/05/2025 15:05	94.0634	245
08/04/2025 19:10	93.3335	187
08/04/2025 19:05	93.3324	186
08/04/2025 21:05	93.2659	185

B. Pivotal Suppliers[10]

Figure 23 illustrates the top 10 system-wide pivotal suppliers in the market during Q3-2025. The GNPower Dinginin Coal-Fired Thermal Power Plant (CFTPP) remained the most pivotal plant, similar with Q2-2025, being identified as pivotal in 8,238 trading intervals, or 31% of the total trading intervals for the quarter. The Batangas Combined-

[10] The Pivotal Supply Index (PSI) measures how critical a particular generator is in meeting the total demand at a particular time. It is a binary variable (1 for pivotal and 0 for not pivotal) which measures the frequency that a generating is pivotal for a particular period.

Cycle Power Plant (CCPP) ranked second, pivotal in 8,053 intervals or approximately 30% of the time.

Despite an average RSI of 100.48% during Q3-2025, slightly above the 100th threshold, the market faced tighter operational conditions due to lower effective supply and elevated outage levels.

Additionally, it is worth noting that six (6) out of the ten (10) pivotal suppliers were coal-fired power plants, while three (3) were natural gas power plants and one (1) hydro power plants.

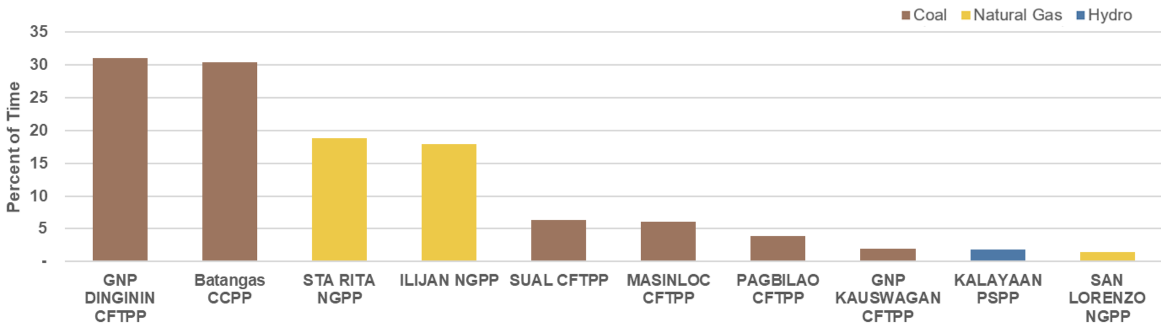


Figure 23. Top 10 System: Pivotal Suppliers, Q3-2025

VI. CAPACITY FACTOR

The Capacity Factor, which measures the efficiency of generating units based on actual metered output relative to their maximum potential generation, averaged 45% during the quarter under review. This represents a decrease compared to the 48% recorded in the preceding quarter.

The slight decline was primarily driven by lower system demand during the period. However, prevailing offer prices incentivized greater dispatch of available units, resulting in increased electricity generation from power plants. This dynamic suggests that while overall demand softened, the supply-side response was shaped by competitive bidding strategies, ensuring that lower-priced offers were prioritized in the dispatch stack.

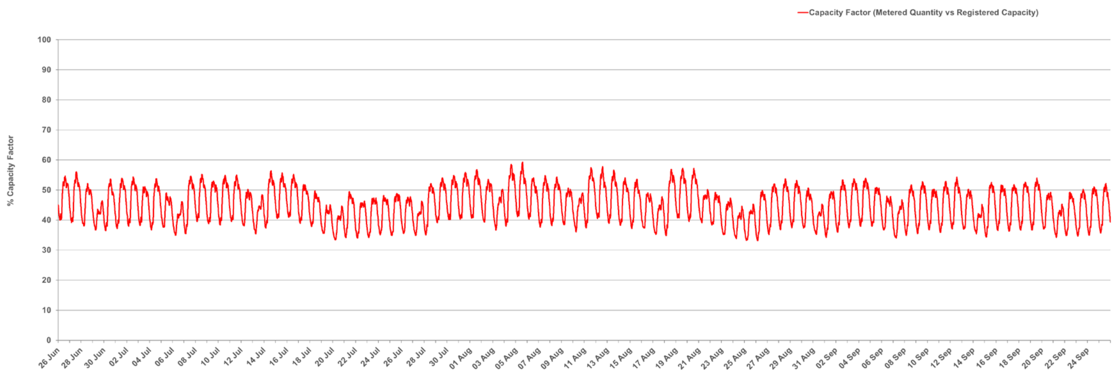


Figure 24. System: Capacity Factor (Metered Quantity vs Registered Capacity), Q3-2025

By resource type, baseload power plants accounted for the largest share of dispatch in the WESM, reflecting their dominant role in system utilization. Geothermal power plants recorded the highest capacity factor at 59.82%, followed closely by coal power plants at 59.14% *(see Figure 25).*

Geothermal power plants having the largest utilization can be attributable to its priority dispatch status and stable resource availability. In contrast, coal plants, despite competitive offers, were slightly constrained by increased outage levels, which limited overall utilization.

Natural gas plants ranked third, with capacity factors improving by 3.57% compared to the preceding quarter. Hydro plants also recorded a significant increase of 14.97%, supported by higher water availability during the rainy season[11]. Oil-fired and battery plants continued to record the lowest utilization levels, consistent with their function as peaking units. Their dispatch was limited to periods of system stress or high demand conditions.

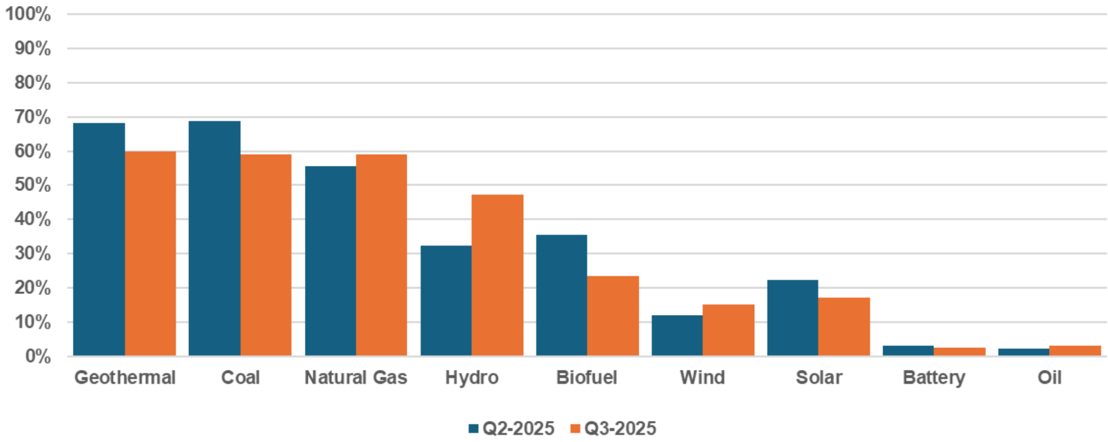


Figure 25. System Capacity Factor Per Resource Type (Registered Capacity vs Actual Generation) – Q2-2025 and Q3-2025

VII. SPOT EXPOSURE

The load-market participants' spot market transactions experienced a slight decrease during Q3-2025, averaging 14.90%, compared to 20.81% in Q2-2025. This indicates that majority of total energy purchases remained covered by bilateral contracts.

Daily analysis shows variations in spot exposure between Q3 for 2024 and 2025. In most instances, spot exposure during Q3-2024 was consistently higher than in Q3-2025, with the largest difference of 13.2% occurring on 31 August 2025. The reduction in spot exposure in 2025 can be attributed to generating units with bilateral contracts remaining available and delivering their committed energy to their respective loads, rather than relying on the spot market. This behavior was also linked to lower market prices, as generators offered at lower price levels to ensure dispatch and fulfill their bilateral obligations which resulted in a lower average price for Q3-2025 *(see Figure 26)*.

---

[11] PAGASA Press Release: *Onset of the Rainy Season*: DOST-PAGASA S&T Media: Link https://www.pagasa.dost.gov.ph/pressrelease/181#:~:text=02%20June%202025&text=This%20signifies%20the%20onset%20of,referred%20to%20as%20monsoon%20breaks.

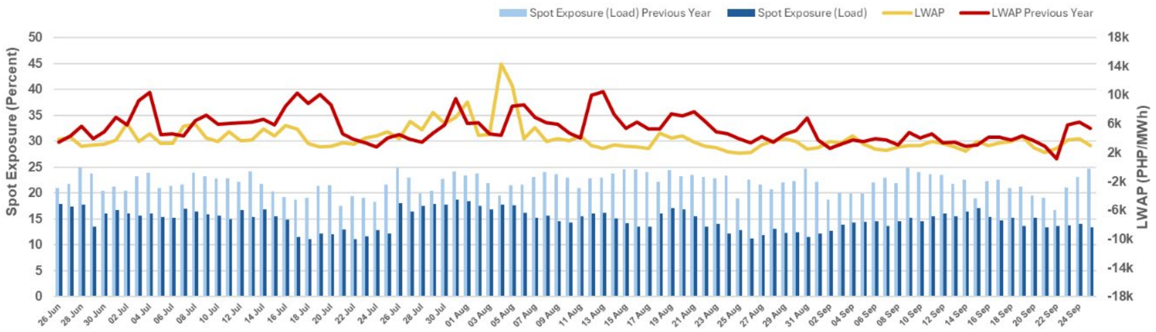


Figure 26. Daily Profile of Spot Market Exposure, Q3 2024 vs Q3-2025

Hourly analysis of spot exposure and corresponding average prices reveals distinct intraday patterns. Spot exposure peaked at 1200h, largely driven by the high solar generation during midday that displaced bilateral supply and increased transactions in the spot market. A secondary peak occurred at 2000h, coinciding with the evening demand ramp when solar output had fully declined and additional dispatchable capacity was required.

Despite these peaks in spot exposure, prices remained relatively stable during midday due to sufficient available capacity. In contrast, slight price increases were observed at 1700h and 1900h, aligning with transition periods when demand rose while variable renewable energy output declined. This tightening of the supply-demand balance during early evening hours exerted upward pressure on prices, even as spot exposure remained moderate.

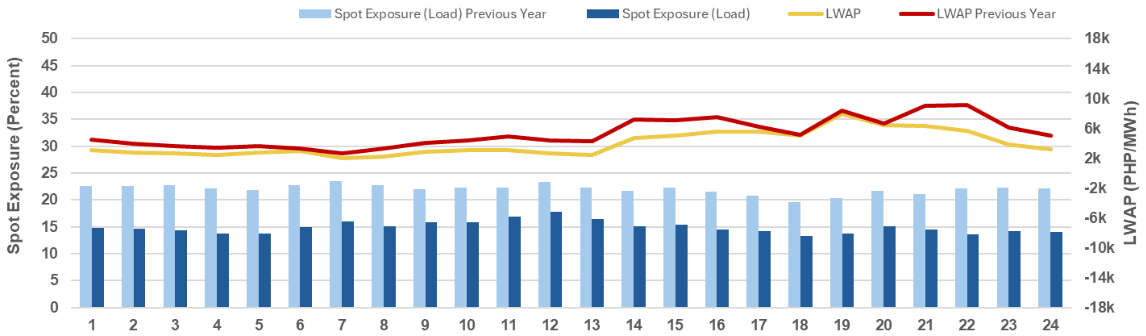


Figure 27. Hourly Profile of Spot Market Exposure, Q2 2024 vs Q2-2025

Annex A. Plants with Change in Capacity

Plant Type	Resource ID	Facility Name	Registered Capacity		Quarter-on-Quarter Change (MW)
			2025-Q2	2025-Q3	
Luzon					
WIND	01BALWIND_G01	Balaoi and Caunayan Wind Power Project Phase 1	80	22.4	-57.60
SOLR	01BONGSOL_G01	Bongabon Solar Power Project	18.8	19.8	1.00
HYD	01CASECN_U01	Casecnan Hydroelectric Power Plant Unit 1	79.1	82.5	3.40
HYD	01CASECN_U02	Casecnan Hydroelectric Power Plant Unit 2	78.9	82.5	3.60
SOLR	01CONSOL_G01	Concepcion 1 Solar Power Project	76	82.5	6.50
SOLR	01CORDONSOL_G	Cordon Solar Power Project	52.8	52.7	-0.10
OIL	01TPCBUNK_G01	Bunker C-Fired Diesel Power Plant	18.1	16.8	-1.30
BAT	03BACMAN_BAT	Bac-Man Energy Storage System	28.5	20	-8.50
COAL	03CALACA_G01	Batangas Coal-Fired Thermal Power Plant 1	240	250	10.00
COAL	03CALACA_G02	Batangas Coal Fired Thermal Power Plant 2	300	310	10.00
HYD	03CALIRY_G01	Caliraya Hydro Electric Power Plant	39.3	37	-2.30
NATG	03EERI_G03	Batangas Combined Cycle Power Plant Unit 3	440	419.6	-20.40
GEO	03ORMAT_G01	Makban-Binary 1 Geothermal Power Plant	6	3	-3.00
GEO	03TGPP_G01	Geothermal Binary Power Plant	16.7	9.7	-7.00
GEO	03MKBN_C	Makban-Calauan Geothermal Power Plant (Plant C)	30	0	-30.00
Visayas					
OIL	04CLBYBNK_G01	Calbayog Bunker C-Fired Diesel Power Plant	11	10.9	-0.10
HYD	04UTH_G01	Upper Taft Hydroelectric Power Plant	14.2	13.8	-0.40
OIL	05CPPC_U08	Bunker C-Fired Diesel Power Plant (BCFDPP) Unit 8	6.5	6.3	-0.20
OIL	05CPPC_U09	Bunker C-Fired Diesel Power Plant (BCFDPP) Unit 9	6.5	6.3	-0.20
OIL	05CPPC_U10	Bunker C-Fired Diesel Power Plant (BCFDPP) Unit 10	6.5	6.3	-0.20
OIL	06CENPRI_U01	Calumangan Bunker C-Fired Diesel Power Plant Unit 1	4.5	4.4	-0.10
OIL	06CENPRI_U02	Calumangan Bunker C-Fired Diesel Power Plant Unit 2	4.5	4.4	-0.10
OIL	06CENPRI_U03	Calumangan Bunker C-Fired Diesel Power Plant Unit 3	4.5	4.4	-0.10
BIOF	06STNEGB_G01	SNBP Biomass Power Plant (BPP)	25	21.9	-3.10
OIL	07BIDPP_G01	Bohol In-Island Diesel Power Plant	57	53.3	-3.70
Mindanao					
COAL	11MINBAL_G01	Balingasag Coal Fired Thermal Power Plant Units 1-3	165	150	-15.00
OIL	12NACSUR_G01	Diesel Power Plant	10.7	10.4	-0.30

Annex B-1. Capacity Profile by Category

Capacity Profile	3rd Quarter of 2024 (26 Jun to 25 Sept)		2nd Quarter of 2025 (26 Apr to 25 Jun)		3rd Quarter of 2025 (26 Jun to 25 Sept)	
	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap
Capacity Offered/Nominated	19,136.26	65.91%	21,422.38	72.07%	20,516.25	68.64%
Capacity on Commissioning	1,559.22	5.37%	642.98	2.16%	199.21	0.67%
Capacity not Offered/Nominated	4,620.03	15.91%	5,433.20	18.28%	5,471.33	18.30%
Capacity on Outage	3,983.49	13.72%	2,278.46	7.67%	3,515.08	11.76%

Capacity Profile	%Change 3rd Qtr 2025 to 3rd Qtr 2024 (in MW)	%Change 3rd Qtr 2025 to 2nd Qtr 2025 (in MW)
Capacity Offered/Nominated	7.21% ▲	4.23% ▼
Capacity on Commissioning	87.22% ▼	69.02% ▼
Capacity not Offered/Nominated	18.43% ▲	0.70% ▲
Capacity on Outage	11.76% ▼	54.27% ▲

Capacity Profile	July 2025		August 2025		September 2025	
	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap
Capacity Offered/Nominated	20,589.15	69.38%	20,447.82	68.93%	20,514.14	68.92%
Capacity on Commissioning	158.22	0.53%	162.94	0.55%	275.29	0.92%
Capacity not Offered/Nominated	5,491.48	18.50%	5,489.59	18.51%	5,433.51	18.26%
Capacity on Outage	3,437.76	11.58%	3,564.39	12.02%	3,540.65	11.90%

Annex B-2. Capacity Profile by Plant Type

Offered/Nominated Capacity by Plant Type

Plant Type	2nd Quarter of 2025 (26 Apr to 25 Jun)		3rd Quarter of 2025 (26 Jun to 25 Sept)		Quarter-on-Quarter % Change
	Average (in MW)	Percentage	Average (in MW)	% of Reg Cap	
Coal	10,966.64	51.19%	9,432.89	45.16%	13.99%▼
Natural Gas	3,300.01	15.41%	4,013.73	19.22%	21.63%▲
Geothermal	1,201.46	5.61%	1,086.88	5.20%	9.54%▼
Hydro	2,491.31	11.63%	2,624.70	12.57%	5.35%▲
Oil Based	2,167.91	10.12%	2,132.07	10.21%	1.65%▼
Wind	61.61	0.29%	81.62	0.39%	32.49%▲
Solar	605.38	2.83%	879.90	4.21%	45.35%▲
Biofuel	160.50	0.75%	100.90	0.48%	37.13%▼
Battery Storage	466.57	2.18%	533.23	2.55%	14.29%▲

Effective Supply by Plant Type

Plant Type	2nd Quarter 2025		3rd Quarter 2025		Quarter-on-Quarter % Change
	Average (in MW)	% of RegCap	Average (in MW)	% of RegCap	
Coal	8,519.96	51.54%	8,051.36	47.32%	5.50%▼
Natural Gas	2,822.37	17.07%	2,995.09	17.60%	6.12%▲
Geothermal	601.20	3.64%	1,092.07	6.42%	81.65%▲
Hydro	2,061.51	12.47%	2,387.31	14.03%	15.80%▲
Oil Based	1,478.16	8.94%	1,257.08	7.39%	14.96%▼
Wind	54.08	0.33%	85.98	0.51%	58.99%▲
Solar	535.35	3.24%	511.01	3.00%	4.55%▼
Biofuel	95.97	0.58%	100.85	0.59%	5.08%▲
Battery Storage	361.18	2.19%	535.03	3.14%	48.13%▲

RTD Capacity by Plant Type

Plant Type	2nd Quarter 2025 (26 Mar 2025 to 25 Jun 2025)		3rd Quarter 2025 (26 Jun to 25 Sept 2025)		Quarter-on-Quarter % Change
	Average(in MW)	% of RegCap	Average(in MW)	% of RegCap	
Coal	8,050.11	61.63%	7,662.64	54.78%	4.81%▼
Natural Gas	2,553.67	19.55%	2,705.71	19.34%	5.95%▲
Geothermal	599.90	4.59%	1,091.21	7.80%	81.90%▲
Hydro	1,154.60	8.84%	1,780.46	12.73%	54.21%▲
Oil Based	17.61	0.13%	46.46	0.33%	163.78%▲
Wind	54.06	0.41%	85.96	0.61%	58.99%▲
Solar	534.54	4.09%	510.61	3.65%	4.48%▼
Biofuel	95.92	0.73%	100.83	0.72%	5.11%▲
Battery Storage	1.43	0.01%	3.16	0.02%	121.02%▲

Annex C. Details and Breakdown for the Others*

July 2025

Event Category	Total Count per Hour Inteval
TESTING AND COMMISSIONING	1,323
OUTAGE (AGGREGATED UNIT/S) AND DERATING-PLANT PROBLEM	1,202
CO-GENERATION POWER PLANTS	1,108
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-GEOTHERMAL	1,016
DISTRIBUTION-LINE RELATED CONSTRAINTS	907
WITH PENDING/ONGOING REGISTRATION UPDATE	788
DERATING-PLANT DEGRADATION/CONDITION	719
TRANSMISSION-RELATED CONSTRAINTS	587
RESOURCE CONSTRAINTS-SOLAR	466
DERATING-AMBIENT CONDITIONS	390
OUTAGE (AGGREGATED UNIT/S) AND CO-GENERATION	353
START-UP PROCEDURES	324
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-HYDRO	202
FORCE MAJEURE	159
SHUTDOWN PROCEDURES	87
DERATING-PLANT EQUIPMENT-RELATED MAINTENANCE (PLANT TEST)	81
DERATING-AMBIENT CONDITION AND PLANT PROBLEM/MAINTENANCE	28
RESOURCE CONSTRAINTS-GEOTHERMAL & DERATING-PLANT PROBLEM/MAINTENANCE	17
RESOURCE CONSTRAINTS-HYDRO & TRANSMISSION-RELATED CONSTRAINTS	9
RESOURCE CONSTRAINTS-WIND	5

August 2025

Event Category	Total Count per Hour Inteval
OUTAGE (AGGREGATED UNIT/S) AND DERATING-PLANT PROBLEM	1,461
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-GEOTHERMAL	1,329
TESTING AND COMMISSIONING	972
DISTRIBUTION-LINE RELATED CONSTRAINTS	793
DERATING-PLANT DEGRADATION/CONDITION	717
START-UP PROCEDURES	632
OUTAGE (AGGREGATED UNIT/S) AND CO-GENERATION	567
WITH PENDING/ONGOING REGISTRATION UPDATE	518
CO-GENERATION POWER PLANTS	504
TRANSMISSION-RELATED CONSTRAINTS	409
RESOURCE CONSTRAINTS-SOLAR	325
RESOURCE CONSTRAINTS-GEOTHERMAL & DERATING-PLANT PROBLEM/MAINTENANCE	180
DERATING-PLANT EQUIPMENT-RELATED MAINTENANCE (PLANT TEST)	111
RESOURCE CONSTRAINTS-WIND	106
DERATING-AMBIENT CONDITIONS	90
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-HYDRO	52
SHUTDOWN PROCEDURES	38
Unknown	24
FORCE MAJEURE	20
ISLAND MODE OPERATION	15
RESOURCE CONSTRAINTS-GEOTHERMAL & AMBIENT CONDITION	11
DERATING-AMBIENT CONDITION AND PLANT PROBLEM/MAINTENANCE	11
LEGAL OR REGULATORY COMPLIANCES	6
PUMP STORAGE POWER PLANTS	2

September 2025

Event Category	Total Count per Hour Inteval
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-GEOTHERMAL	1,492
OUTAGE (AGGREGATED UNIT/S) AND DERATING-PLANT PROBLEM	1,477
DISTRIBUTION-LINE RELATED CONSTRAINTS	849
TESTING AND COMMISSIONING	813
OUTAGE (AGGREGATED UNIT/S) AND CO-GENERATION	743
DERATING-PLANT DEGRADATION/CONDITION	742
CO-GENERATION POWER PLANTS	742
FORCE MAJEURE	617
RESOURCE CONSTRAINTS-SOLAR	539
TRANSMISSION-RELATED CONSTRAINTS	357
START-UP PROCEDURES	261
RESOURCE CONSTRAINTS-GEOTHERMAL & DERATING-PLANT PROBLEM/MAINTENANCE	191
DERATING-PLANT EQUIPMENT-RELATED MAINTENANCE (PLANT TEST)	111
RESOURCE CONSTRAINTS-WIND	87
OUTAGE (AGGREGATED UNIT/S) AND RESOURCE CONSTRAINTS-HYDRO	78
SHUTDOWN PROCEDURES	44
RESOURCE CONSTRAINTS-HYDRO & TRANSMISSION-RELATED CONSTRAINTS	32
PUMP STORAGE POWER PLANTS	5

Annex D-1.1. Capacity on Outage by Plant Type

Plant Type	2nd Quarter 2025 (26 Mar 2025 to 25 Jun 2025)		3rd Quarter 2025 (26 Jun to 25 Sept 2025)		Quarter-on-Quarter % Change
	Average(in MW)	% of RegCap	Average(in MW)	% of RegCap	
Coal	689.72	26.37%	1,997.33	54.73%	189.59% ▲
Natural Gas	657.26	25.13%	415.72	11.39%	36.75% ▼
Geothermal	152.01	5.81%	241.92	6.63%	59.15% ▲
Hydro	359.17	13.73%	273.51	7.49%	23.85% ▼
Oil Based	526.05	20.11%	552.89	15.15%	5.10% ▲
Wind	41.96	1.60%	29.30	0.80%	30.18% ▼
Solar	47.51	1.82%	48.54	1.33%	2.17% ▲
Biofuel	64.24	2.46%	52.79	1.45%	17.83% ▼
Battery Storage	77.69	2.97%	37.41	1.03%	51.84% ▼

Plant Type	July 2025	August 2025	September 2025
	Average(in MW)	Average(in MW)	Average(in MW)
Coal	2,033.02	2,226.29	1,733.82
Natural Gas	337.25	213.67	672.83
Geothermal	221.77	285.58	217.74
Hydro	316.80	218.62	286.52
Oil Based	543.19	545.99	569.17
Wind	30.51	17.76	61.89
Solar	48.16	42.63	64.42
Biofuel	60.19	52.54	45.87
Battery Storage	39.40	44.39	21.92

Plant Type	July 2025	August 2025	September 2025
	Average(in MW)	Average(in MW)	Average(in MW)
Coal	2,033.0187	2,226.2916	1,733.8235
Natural Gas	337.2527	213.6726	672.8341
Geothermal	221.7654	285.5839	217.7445
Hydro	316.8012	218.6229	286.5202
Oil Based	543.1950	545.9870	569.1664
Wind	30.5140	17.7611	61.8899
Solar	48.1615	42.6277	64.4183
Biofuel	60.1899	52.5424	45.8651
Battery Storage	39.3967	44.3944	21.9242

Plant Type	July 2025 (26 June to 25 July)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Coal	489.70	06/28/2025 12:10	3,713.20	07/25/2025 20:05	2,033.02
Natural Gas	190.00	07/03/2025 19:35	720.00	07/12/2025 0:05	337.25
Geothermal	145.60	07/23/2025 6:25	364.40	07/10/2025 23:55	221.77
Hydro	40.10	07/01/2025 7:35	799.80	07/16/2025 10:20	316.80
Oil Based	495.10	07/22/2025 16:25	655.10	07/16/2025 15:00	543.19
Wind	13.20	07/07/2025 6:25	52.90	06/28/2025 6:30	30.51
Solar	4.80	07/12/2025 18:00	209.70	07/16/2025 18:50	48.16
Biofuel	43.40	07/04/2025 8:20	109.20	07/19/2025 11:40	60.19
Battery Storage	20.00	07/07/2025 16:10	70.00	07/11/2025 6:25	39.40

Plant Type	August 2025 (26 July to 25 August)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Coal	1,031.10	08/12/2025 11:45	3,738.20	07/26/2025 7:20	2,226.29
Natural Gas	190.00	07/26/2025 0:05	607.40	07/26/2025 22:50	213.67
Geothermal	46.70	08/04/2025 3:50	531.56	08/15/2025 0:25	285.58
Hydro	85.60	08/11/2025 20:10	506.20	07/31/2025 14:05	218.62
Oil Based	462.10	07/26/2025 0:05	661.60	08/01/2025 23:15	545.99
Wind	13.20	07/07/2025 6:25	80.00	07/30/2025 20:30	17.76
Solar	3.40	08/14/2025 10:55	221.90	08/22/2025 5:10	42.63
Biofuel	32.60	08/22/2025 11:05	93.50	08/24/2025 14:25	52.54
Battery Storage	20.00	07/07/2025 16:10	90.00	08/20/2025 20:20	44.39

Plant Type	September 2025 (26 August to 25 September)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Coal	679.80	09/19/2025 0:05	3,428.70	08/30/2025 4:10	1,733.82
Natural Gas	190.00	08/26/2025 0:05	863.00	09/04/2025 0:20	672.83
Geothermal	137.00	09/16/2025 19:45	401.48	08/31/2025 7:00	217.74
Hydro	137.10	08/13/2025 14:50	537.70	09/09/2025 7:05	286.52
Oil Based	522.10	08/24/2025 12:05	694.30	09/15/2025 0:05	569.17
Wind	36.70	07/19/2025 4:05	131.00	09/22/2025 11:30	61.89
Solar	14.50	07/27/2025 6:35	189.50	09/22/2025 22:15	64.42
Biofuel	37.70	08/23/2025 14:35	82.90	09/04/2025 17:15	45.87
Battery Storage	14.20	09/15/2025 0:05	40.00	06/26/2025 0:05	21.92

Annex D-2.1. Capacity on Outage by Category

Plant Category	2nd Quarter 2025 (26 Mar 2025 to 25 Jun 2025)		3rd Quarter 2025 (26 Jun to 25 Sept 2025)		Quarter-on-Quarter % Change
	Average(in MW)	% of RegCap	Average(in MW)	% of RegCap	
Planned	335.35	14.61%	1,606.55	45.17%	379.06% ▲
Maintenance	409.95	17.86%	127.29	3.58%	68.95% ▼
Forced	1,516.88	66.09%	1,799.59	50.59%	18.64% ▲
Deactivated Shutdown	33.00	1.44%	23.45	0.66%	28.95% ▼

Plant Category	July 2025	August 2025	September 2025
	Average(in MW)	Average(in MW)	Average(in MW)
Planned	1,638.09	1,332.65	1,851.20
Maintenance	158.48	121.38	103.02
Forced	1,709.03	2,110.33	1,576.49
Deactivated Shutdown	33.00		11.50

Plant Category	July 2025 (26 June to 25 July)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Planned	50.00	06/29/2025 16:00	2,755.80	07/14/2025 0:15	1,638.09
Maintenance	40.80	06/26/2025 0:05	815.30	07/05/2025 9:05	158.48
Forced	1,063.00	07/10/2025 0:35	3,501.50	07/25/2025 8:40	1,709.03
Deactivated Shutdown	33.00	06/26/2025 0:05	33.00	06/26/2025 0:05	33.00

Plant Category	August 2025 (26 July to 25 August)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Planned	953.00	08/08/2025 8:05	1,982.90	08/15/2025 0:25	1,332.65
Maintenance	16.80	08/04/2025 3:50	735.80	07/25/2025 20:05	121.38
Forced	1,132.26	08/13/2025 22:00	3,560.90	07/29/2025 19:55	2,110.33
Deactivated Shutdown		07/26/2025 0:05		07/26/2025 0:05	

Plant Category	September 2025 (26 August to 25 September)				
	Min		Max		Average
	In MW	Date and Time Interval	In MW	Date and Time Interval	In MW
Planned	1,149.80	09/25/2025 18:45	2,560.30	09/15/2025 9:05	1,851.20
Maintenance	52.20	08/22/2025 8:05	479.20	08/28/2025 0:05	103.02
Forced	821.90	09/18/2025 21:30	3,355.48	08/30/2025 4:10	1,576.49
Deactivated Shutdown	11.50	08/26/2025 0:15	11.50	08/26/2025 0:15	11.50

Annex E-1. Supply and Demand

Capacity Profile	3rd Quarter of 2024 (26 Jun to 25 Sept)		2nd Quarter of 2025 (26 Apr to 25 Jun)		3rd Quarter of 2025 (26 Jun to 25 Sept)	
	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap	Average (in MW)	% of Reg Cap
System Demand	14,108.50	48.60%	14,969.63	50.36%	13,995.44	46.82%
Effective Supply	16,566.68	57.06%	18,024.76	60.64%	17,025.61	56.96%
Demand Plus Reserve Schedule	15,750.61	54.25%	17,012.68	57.23%	15,946.25	53.35%

Capacity Profile	%Change 3rd Qtr 2025 to 3rd Qtr 2024 (in MW)	%Change 3rd Qtr 2025 to 2nd Qtr 2025 (in MW)
System Demand	0.80% ▼	6.51% ▼
Effective Supply	2.77% ▲	5.54% ▼
Demand Plus Reserve Schedule	1.24% ▲	6.27% ▼

Capacity Profile	July 2025	August 2025	September 2025
	Average(in MW)	Average(in MW)	Average(in MW)
System Demand	13,964.94	14,231.93	13,995.44
Effective Supply	16,952.49	17,200.45	17,025.61
Demand Plus Reserve Schedule	15,963.83	16,208.40	15,946.25

Philippine Electricity Market Corporation

QMAR-2025-01

Annex F. Load Weighted Average Prices

Load Weighted Average Prices (Quarterly)

	2nd Quarter of 2025 (26 Apr to 25 Jun)			3rd Quarter of 2025 (26 Jun to 25 Sept)			Quarter-on-Quarter % Change
	Min	Max	Average	Min	Max	Average	
System	-10,466.61	51,795.75	4,327.31	-9,431.86	50,708.91	3,872.19	10.52%▼

Load Weighted Average Prices (Monthly)

	July 2025 (26 June to 25 July)			August 2025 (26 July to 25 August)			September 2025 (26 August to 25 September)		
	Min	Max	Average	Min	Max	Average	Min	Max	Average
System	-9,431.86	26,258.17	3,985.11	-1,020.57	50,708.91	4,593.79	-6,452.92	20,230.84	3,041.31
Luzon	-9,356.00	30,020.75	3,923.17	-1,020.57	50,107.71	3,760.81	-9,980.65	20,236.12	2,568.28
Visayas	-9,393.48	34,689.45	4,388.94	-1,020.57	50,168.26	6,395.22	-0.03	29,016.30	4,022.76
Mindanao	-10,009.21	29,883.63	3,796.99	-1,020.57	54,168.58	6,658.77	-0.03	29,567.58	4,189.55

Zonal Prices (Monthly)

Zones	July 2025 (26 June to 25 July)	August 2025 (26 July to 25 August)	September 2025 (26 August to 25 September)
Luzon			
Northern Luzon	4,076.98	3,928.01	2,628.02
Metro Manila	4,094.67	3,924.00	2,662.45
Southern Luzon	3,993.00	3,903.71	2,607.11
Visayas			
Bohol	4,632.72	7,090.65	4,396.50
Cebu	4,548.70	6,978.53	4,295.82
Leyte	4,616.13	7,362.71	4,315.82
Negros	4,580.69	7,149.34	4,391.67
Panay	4,711.98	7,376.46	4,474.49
Mindanao			
Lanao	3,562.78	6,320.08	4,027.53
North Central Mindana	3,748.95	6,952.70	4,179.69
North-East Mindanao	4,215.39	7,894.90	4,747.85
North-West Mindanao	4,245.48	7,613.99	4,920.02
South-East Mindanao	3,989.70	7,499.20	4,515.10
South-West Mindanao	4,118.81	7,893.66	4,599.43